DCP Midstream Partners, LP
Form 10-K
March 01, 2006

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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, 2005

or

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

Commission file number: 001-32678

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

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

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

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

Title of Each Class:	**Name of Each Exchange on Which Registered:**
Common Units Representing Limited Partner Interests	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities and 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, or a non-accelerated filer (see definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Act) (Check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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 December 30, 2005, was approximately $251,044,000. The aggregate market value was computed by reference to the last sale price ($24.50 per common unit) of the registrant s common units on the New York Stock Exchange on December 30, 2005.

As of February 17, 2006, there were outstanding 10,357,143 common limited partner units and 7,142,857 subordinated units.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

DCP MIDSTREAM PARTNERS, LP
Form 10-K For the Year Ended December 31, 2005

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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:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- our use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- the amount of collateral required to be posted from time to time in our transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the increased regulation of the gathering and processing industry;
- the timing and extent of changes in commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain required approvals for construction or modernization of gathering and processing facilities, and the timing of production from such facilities, which are dependent on the issuance by federal, state and municipal governments, or agencies thereof, of building, environmental and other permits, the availability of specialized contractors and work force and prices of and demand for products;
- our ability to grow through acquisitions or internal growth projects;
- the extent of success in connecting natural gas supplies to gathering and processing systems; 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

We are a Delaware limited partnership recently formed by Duke Energy Field Services, LLC, which we refer to as DEFS, 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 and the business of transporting and selling natural gas liquids, or NGLs.

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Supported by our relationship with DEFS and its parents, Duke Energy Corporation, which we refer to as Duke Energy, and ConocoPhillips, we intend to acquire and construct additional assets and we have a management team dedicated to executing our growth strategy.

Our operations are organized into two business segments, Natural Gas Services and NGL Logistics.

Our Natural Gas Services segment is comprised of our North Louisiana system, which is an approximately 1,430-mile integrated pipeline system located in northern Louisiana and southern Arkansas that gathers, compresses, treats, processes, transports and sells natural gas received from approximately 1,100 receipt points, each of which represents production from one or more wells in the adjacent area, and that sells NGLs. This system consists of the following:

the Minden processing plant and gathering system, which includes a cryogenic natural gas processing plant supplied by approximately 700 miles of natural gas gathering pipelines, connected to approximately 460 receipt points, with throughput capacity of approximately 115 million cubic feet per day, or MMcf/d;

the Ada processing plant and gathering system, which includes a 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 PanEnergy Louisiana Intrastate pipeline 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 NGL Logistics segment consists of the following:

our Seabreeze pipeline, an approximately 68-mile intrastate NGL pipeline in Texas with throughput capacity of 33 thousand barrels per day, or 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.

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 adding new volumes of natural gas and NGLs and undertaking additional initiatives to enhance utilization and improve operating efficiencies. Our natural gas assets and NGL pipelines have excess capacity, which allows us to connect new supplies of natural gas and NGLs at minimal incremental cost.

Build: capitalize on organic expansion opportunities. We continually evaluate economically attractive organic expansion opportunities to construct new midstream systems in new operating areas. For example, we believe there are opportunities to expand our North Louisiana system to transport increased volumes of natural gas produced in east Texas to premium markets and interstate pipeline connections on the eastern end of our North Louisiana system.

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. In light of the recent industry trend of large energy companies divesting their midstream assets, we believe there will continue to be acquisition opportunities. We intend to pursue acquisition opportunities both independently and jointly with DEFS and its parents, Duke Energy and ConocoPhillips, and we may also acquire assets directly from them, which 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 primary business objective and business strategies successfully because of the following competitive strengths:

Affiliation with DEFS and its parents. Our relationship with DEFS and its parents, Duke Energy and ConocoPhillips, may provide us with significant business opportunities. DEFS is one of the largest gatherers of natural gas (based on wellhead volume), the largest producer of NGLs and one of the largest marketers of NGLs in North America. Our relationship with DEFS, Duke Energy and ConocoPhillips 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 implementation of our strategies. Additionally, we believe DEFS 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 and efficient operation of our facilities.

Strategically located assets. We own and operate one of the largest integrated natural gas gathering, compression, treating, processing and transportation systems in northern Louisiana, an active natural gas producing area. This system is also well positioned, and we believe there are opportunities to expand this system, to transport increased volumes of natural gas from east Texas and west Louisiana to premium markets on the eastern end of our North Louisiana system and to interconnections with major interstate natural gas pipelines that transport natural gas to consumer markets in the eastern and northeastern United States. Our NGL pipelines are also strategically located to transport NGLs from plants that process natural gas produced in Texas and northern Louisiana to large fractionation facilities and a petrochemical plant along the Gulf Coast.

Stable cash flows. Our operations consist of a favorable mix of fee-based and margin-based services, which together with our hedging activities, generate relatively stable cash flows. While our percentage-of-proceeds gathering and processing contracts subject us to commodity price risk, as of January 1, 2006 we have hedged approximately 80% of our natural gas and NGL commodity price risk related to these arrangements through 2010. As part of our gathering operations, we recover and sell condensate. As of January 1, 2006, we have hedged approximately 80% of our expected condensate commodity price risk relating to our natural gas gathering operations through 2010. For additional information regarding our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operation Quantitative and Qualitative Disclosures about Market Risk Hedging Strategies.

Integrated package of midstream services. We provide an integrated package of services to natural gas producers, including natural gas gathering, compression, treating, processing, transportation and sales, and NGL sales. 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 of the services producers, marketers and others require to move natural gas and NGLs from wellhead to market on a cost-effective basis.

Experienced management team. Our senior management team and board of directors includes some of the most senior officers of DEFS 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 DEFS and its Parents

One of our principal attributes is our relationship with DEFS and its parents, Duke Energy and ConocoPhillips. DEFS commenced operations in 2000 following the contribution to it of the combined North American midstream natural gas gathering, processing and marketing and NGL businesses of Duke Energy and Phillips Petroleum Company (prior to its merger with Conoco Inc.). Currently, DEFS is owned 50% by Duke Energy and 50% by ConocoPhillips.

DEFS intends to use us as an important growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets. We expect to have the opportunity to make acquisitions directly from DEFS in the future. 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 DEFS and its parents, we will have access to a significant pool of management talent, strong commercial relationships throughout the energy industry and access to DEFS broad operational, commercial, technical, risk management and administrative infrastructure.

DEFS has a significant interest in our partnership through its ownership of a 2% general partner interest in us, all of our incentive distribution rights and a 40.0% limited partner interest in us. We have entered into an Omnibus Agreement with DEFS and some of its affiliates that governs our relationship with them regarding certain reimbursement and indemnification matters.

While our relationship with DEFS and its parents is a significant attribute, it is also a source of potential conflicts. For example, DEFS, Duke Energy, ConocoPhillips or their affiliates are not restricted from competing with us. Each of them 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.

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 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 22.1 trillion cubic feet, or Tcf, in 2004 to approximately 25.4 Tcf in 2010, representing an average annual growth rate of over 2.3% per year. The industrial and electricity generation sectors are the largest users of natural gas in the United States. During the last three years, these sectors accounted for approximately 61% of the total natural gas consumed in the United States. In 2004, natural gas represented approximately 24% of all end-user domestic energy requirements. During the last five years, the United States has on average consumed approximately 22.5 Tcf per year, with average annual domestic production of approximately 19.1 Tcf during the same period. Driven by growth in natural gas demand and high natural gas prices, domestic natural gas production is projected to increase from 18.9 Tcf per year to 20.4 Tcf per year between 2004 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 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 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 150ºF. 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.

Natural Gas Services Segment

General

Our Natural Gas Services segment consists of the North Louisiana system, which is a large integrated midstream natural gas system that offers the following services:

- gathering;
- compression;
- treating;

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- processing;
- transportation; and
- sales of natural gas, NGLs and condensate.

The system covers ten parishes in northern Louisiana and two counties in southern Arkansas. Through our North Louisiana system, we offer producers and customers wellhead-to-market services. The North Louisiana system has numerous market outlets for the natural gas that we gather, including several intrastate and interstate pipelines, eight major industrial end-users and three major power plants. The system is strategically located to facilitate the transportation of natural gas from eastern Texas and northern Louisiana to pipeline connections linking to markets in the eastern and northeastern areas of the United States.

The North Louisiana system consists of:

- our Minden processing plant, which has a processing capacity of approximately 115 MMcf/d, and gathering system, which is an approximately 700-mile natural gas gathering system with throughput capacity of approximately 115 MMcf/d;
- our Ada processing plant, which has a processing capacity of approximately 45 MMcf/d, and gathering system, which is an approximately 130-mile natural gas gathering system with throughput capacity of approximately 80 MMcf/d; and
- our PELICO system, an approximately 600-mile intrastate natural gas pipeline with throughput capacity of approximately 250 MMcf/d.

A map representing the location of the assets that comprise the North Louisiana system is set forth below:

Gathering Systems

The North Louisiana natural gas gathering system, consisting of the Minden and Ada gathering systems, has approximately 830 miles of natural gas gathering pipelines, ranging in size from two inches to twelve inches in diameter. The system has aggregate throughput capacity of approximately 195 MMcf/d and average throughput on the system was approximately 134 MMcf/d in 2005. There are 26 compressor stations located within the system, comprised of 60 units with an aggregate of approximately 70,000 horsepower.

The Minden gathering system is an approximately 700-mile natural gas gathering system located in Bossier, Claiborne, Jackson, Lincoln, Ouachita and Webster parishes, Louisiana and two Arkansas counties. The system gathers natural gas from producers at approximately 460 receipt points and delivers it for processing to the Minden processing plant. The Minden gathering system also delivers NGLs produced at the Minden processing plant to the Black Lake pipeline. The Minden gathering system has throughput capacity of approximately 115 MMcf/d, and had aggregate throughput of approximately 66 MMcf/d in 2005.

The Ada gathering system is an approximately 130-mile natural gas gathering system located in Bienville and Webster parishes, Louisiana. The system gathers natural gas from producers at approximately 210 receipt points and delivers it for processing to the Ada processing plant. The Ada gathering system has throughput capacity of approximately 80 MMcf/d, and had throughput of approximately 68 MMcf/d in 2005.

Processing Plants

The Minden processing plant is a cryogenic natural gas processing and treating plant located in Webster parish, Louisiana. The Minden processing plant has a design capacity of 115 MMcf/d. In 2005, the Minden processing plant processed approximately 66 MMcf/d of natural gas and produced approximately 4,300 Bbls/d of NGLs. 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. This processing flexibility enables us to maximize the value of ethane for our customers. In 2002, we upgraded the Minden processing plant to enable greater ethane recovery and rejection capabilities. As part of that project, we reached an agreement with our customers to receive 100% of the realized margin attributable to the incremental value of ethane recovered as an NGL from the natural gas stream when appropriate market conditions exist and until a defined return on the initial investment is reached.

The Ada processing plant is a refrigeration natural gas processing plant located in Bienville parish, Louisiana. The Ada processing plant has a design capacity of 45 MMcf/d. In 2005, the facility processed approximately 53 MMcf/d of natural gas and produced approximately 200 Bbls/d of NGLs.

Transportation System

The PELICO system is an approximately 600-mile intrastate natural gas gathering and transportation pipeline with 250 MMcf/d of capacity and average throughput of approximately 223 MMcf/d in 2005. The PELICO system 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 eastern Texas through its interconnect with other pipelines that transport natural gas from eastern Texas into western Louisiana.

Natural Gas Markets

The North 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 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 North Louisiana system is also connected to eight major industrial end-users and makes deliveries to three power plants. Generally, the gas flows from our Minden and Ada gathering systems and PELICO system from west to east toward the industrial and interstate markets with the exception of some industrial end-users located near the central-southern section of the PELICO system. This flow pattern changes somewhat during the summer when utility loads increase deliveries off the same central-southern section of the PELICO system. Our access to numerous market outlets, including interstate pipelines in northeastern Louisiana that deliver natural gas to premium markets on the northeast and east coast, and to several end-users located on our system provides us with the flexibility to deliver our natural gas supply to markets with the most attractive pricing.

The NGLs extracted from the natural gas at the Minden processing plant are delivered to the Black Lake pipeline through our wholly-owned approximately 9-mile Minden NGL pipeline. The NGLs are sold at market index prices to an affiliate of DEFS and transported to the Mont Belvieu hub via the Black Lake pipeline of which we own a 45% interest. The NGLs extracted from natural gas at the Ada processing plant are sold at market index prices to third parties and are delivered to the third parties trucks at the tailgate of the plant.

Customers and Contracts

The primary suppliers of natural gas to our North Louisiana system are Anadarko Petroleum Corporation and ConocoPhillips (one of our affiliates), which collectively represented approximately 48% of the 355 MMcf/d of natural gas supplied to this system in 2005, 48% of the 328 MMcf/d natural gas supplied to this system in 2004 and 48% of the 322 MMcf/d natural gas supplied to this system in 2003. We actively seek new supplies of natural gas 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. (see Financial Statements and Supplementary Data for further discussion of our significant customers).

We currently have approximately 1,100 receipt points on the North Louisiana system receiving natural gas production from individual wells or groups of wells. Approximately 60% of these receipt points are located on our Minden gathering system and our Ada gathering system. The remaining 40% of these receipt points are located on the PELICO system. The natural gas supplied to the North Louisiana system is generally dedicated to us under individually negotiated long-term contracts that provide for the commitment by the producer of all natural gas produced from designated properties. Generally, the initial term of these purchase agreements is for three to five years or, in some cases, the life of the lease. Our PELICO system receives natural gas from our Minden and Ada gathering systems and processing plants as well as from interconnects with other intrastate pipelines that deliver gas from other producing areas in eastern Texas and northern Louisiana, and from other wellhead receipt points directly connected to the system.

For natural gas that is gathered and then processed at our Minden or Ada processing plants, we purchase the wellhead natural gas from the producers primarily under percentage-of-proceeds arrangements or fee-based arrangements. Our gross margin generated from percentage-of-proceeds gathering and processing contracts is directly correlated to the price of natural gas, NGLs and condensate. To minimize this potential future volatility, in September 2005 we entered into a series of derivative financial instrument agreements to hedge our natural gas, NGLs and condensate. As a result of these transactions, we have hedged effective January 1, 2006, approximately 80% of our share of anticipated natural gas, NGL and condensate attributable to these contracts through 2010. We gather and transport natural gas on the PELICO system under a combination of fee-based transportation agreements and merchant arrangements. Under our merchant arrangements, we, directly or through a subsidiary of DEFS as our agent, purchase natural gas at the wellhead and from third parties and related 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 and related parties. We have entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase natural gas and transport it into our PELICO system where we will buy the gas from DEFS at their weighted average cost plus a contractually agreed to marketing fee. In addition, for a significant portion of the gas that we sell out of our PELICO system, we have entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase that natural gas from us and transport it to a sales point at a price equal to their net weighted average sales price less a contractually agreed to marketing fee. These agreements have a two year term beginning in December 2005. In the case where we purchase and sell from related parties, we may buy and sell natural gas from a subsidiary of DEFS, which in turn would transport and buy and sell these volumes from third parties using their transportation or purchase and sales contracts. In the case of certain

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industrial end-user customers, from time to time we may sell aggregated natural gas to a subsidiary of DEFS which in turn would resell natural gas to these customers. Under these arrangements, we expect that this subsidiary of DEFS would make a profit on these transactions.

Competition

The North Louisiana system experiences competition in all of its local markets. The North Louisiana system s principal areas of competition include obtaining natural gas supplies for the Minden processing plant and Ada processing plant and natural gas transportation customers for the PELICO system. The North Louisiana system s competitors include major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport and/or market natural gas. The PELICO system competes with interstate and intrastate pipelines. These include pipelines owned by Regency Intrastate Gas, LLC, Gulf South Pipeline Company and Tennessee Natural Gas Company. The Minden and Ada processing plants compete with other natural gas gathering and processing systems owned by XTO Energy Inc., Regency Intrastate Gas, LLC, Optigas Inc. and Gulf South Pipeline Company, as well as producer-owned systems.

NGL Logistics Segment

NGL Pipelines

General. Our NGL transportation assets consist of our wholly-owned approximately 68-mile Seabreeze intrastate NGL pipeline 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 2005 average throughput was approximately 27 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, that higher natural gas prices reduce the volume of NGLs produced at plants connected to our NGL pipelines.

Seabreeze Pipeline. Our Seabreeze pipeline is an approximately 68-mile private NGL pipeline with current capacity configured at 33 MBbls/d. It is located along the Gulf Coast area of southeastern Texas. For 2005, average throughput on the pipeline was approximately 16 MBbls/d. Throughput on the pipeline during 2005 was negatively impacted by a shut down of a third party NGL pipeline from March 2004 until June 2005 due to pipeline integrity repairs. The Seabreeze pipeline was put into service in 2002 to deliver an NGL mix to the Formosa Point Comfort Chemical Complex from Williams Markham Gas Plant, a large processing plant with processing capacity of approximately 340 MMcf/d located in Matagorda County, Texas; Enterprise Products Matagorda Plant, a large processing plant with capacity of approximately 250 MMcf/d located in Matagorda County, Texas; and TEPPCO Partners, L.P. s South Dean NGL pipeline. The Seabreeze pipeline is the sole NGL pipeline for the two processing plants and is the only delivery point for the South Dean 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 DEFS. 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 (Boomvang and Nansen offshore production platforms and the Matagorda Island Production Facility). The

Seabreeze pipeline delivers the NGLs it receives from these sources to a fractionator at the Formosa Point Comfort Chemical Complex and the Texas Brine Salt Dome storage facility.

In February 2006, we announced our plans to construct a new 37-mile NGL pipeline to connect a DEFS gas processing plant to the Seabreeze pipeline. The project is estimated to be completed during the fourth quarter of 2006 and is supported by a 10-year NGL product dedication by DEFS. Volumes from DEFS are estimated to be approximately 5.3 MBbls/d.

A map illustrating the location of the Seabreeze pipeline is set forth below:

Effective December 1, 2005, we entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase the NGLs that were historically purchased by us, and DEFS 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 pipeline; rather, the shipper retains title and the associated commodity price risk. DEFS is the sole shipper on the Seabreeze pipeline under a 17-year transportation agreement expiring in 2022. The Seabreeze pipeline only collects fee-based transportation revenue under this agreement. DEFS receives its supply of NGLs that it then transports on the Seabreeze pipeline under a 20-year NGL purchase agreement with Williams expiring in 2022 and a 5-year NGL purchase agreement with Enterprise Products Partners expiring in 2007. Under these agreements, Williams and Enterprise Products Partners have each dedicated all of their respective NGL production from these processing plants to DEFS. The Seabreeze pipeline delivers all of DEFS volumes to a fractionator at the Formosa Point Comfort Chemical Complex and the Texas Brine Salt Dome storage facility operated by Underground Services Markam. DEFS has a 20-year long-term sales agreement with Formosa expiring in 2022. Additionally, DEFS has a 10-year transportation agreement with TEPPCO Partners, L.P. expiring in 2012 that covers all of the NGL volumes transported on TEPPCO Partners, L.P. s South Dean NGL pipeline for delivery to the Seabreeze pipeline.

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Black Lake Pipeline. We own a 45% interest in Black Lake, which owns an approximately 317-mile FERC-regulated interstate NGL pipeline with 40 MBbls/d of capacity. For 2005, average throughput on the pipeline was approximately 11 MBbls/d. A map representing the location of the Black Lake pipeline is set forth below:

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, which have aggregate natural gas processing capacity of approximately 345 MMcf/d. The Black Lake pipeline is the sole NGL pipeline for all of these natural gas processing plants in northern Louisiana. In addition, the Black Lake pipeline receives a NGL mix from DEFS Jasper pipeline, which has NGL throughput capacity of approximately 18 MBbls/d and is the sole NGL pipeline for the Brookeland gas plant. The Brookeland gas plant, which is located in southeastern Texas, is 80% owned by DEFS. In December 2005, DEFS entered into an agreement to sell its interest in the Brookeland gas plant and Jasper pipeline to an unaffiliated third party. The sale of Brookeland gas plant and Jasper pipeline is scheduled to close in the first half of 2006. In conjunction with the purchase and sale agreement, the parties entered into an NGL dedication agreement whereby the purchaser must dedicate all NGLs from the related assets to and for the benefit of a subsidiary of DEFS for transportation on the Black Lake pipeline. This dedication agreement will commence on the closing date of the Brookeland gas plant sale and will expire on the fifth anniversary of such date.

There are currently five active shippers on the pipeline, with DEFS historically being the largest, representing approximately 5.4 MBbls/d in 2005. The Black Lake pipeline generates revenues through a FERC-regulated tariff. The current average rate per barrel is $0.91 for 2005.

Black Lake is a partnership that is owned 45% by us, 5% by an affiliate of DEFS and 50% by BP. BP is the operator of the pipeline. 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 in 2007; however, we anticipate cash distributions will resume prior to the completion of this project.

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, referred to as DOT, under the Accountable Pipeline and Safety Partnership Act of 1996, 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 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, referred to as 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 $6.1 million between 2006 and 2010 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. DEFS 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 2005 through 2007 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 scheduled pipeline integrity testing occurring during 2006 and 2007.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations 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 continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, referred to as 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 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.

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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. 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 NGPA. Under Section 311, intrastate pipelines providing interstate service may avoid jurisdiction that would otherwise apply under the Natural Gas Act. 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. 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 Natural Gas Act jurisdiction by FERC and/or the imposition of administrative, civil and criminal penalties. The PELICO system is subject to FERC jurisdiction under Section 311 of the NGPA. The maximum rate that the PELICO system may currently charge is $0.1965 per MMBtu. Pursuant to a FERC order, the PELICO system is required to file a new Section 311 rate case with FERC in 2006 at which time the PELICO system s rates, terms and conditions of service may be subject to change, which we do not expect to have a material adverse effect on our business.

Gathering Pipeline Regulation

Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of FERC under the Natural Gas Act. We believe that the natural gas pipelines in our North Louisiana system 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.

Louisiana s Pipeline Operations Section of the Department of Natural Resources Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana, and has authority to review and authorize natural gas transportation transactions, and the construction, acquisition, abandonment and interconnection of physical facilities. Historically, apart from pipeline safety, it has not acted to exercise this jurisdiction respecting gathering facilities.

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

Interstate NGL Pipeline Regulation

The Black Lake pipeline is an interstate NGL pipeline subject to FERC regulation. The FERC regulates interstate NGL pipelines under its Oil Pipeline Regulations, the Interstate Commerce Act (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, usually meaning that the origin point and destination point are in different states, 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.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, transporting, processing or storing natural gas, 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:

- 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, and 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. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat, fractionate and process natural gas. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

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.

DEFS has agreed to indemnify us in an aggregate amount not to exceed $15.0 million for three years from the closing of our initial public offering for environmental noncompliance and remediation liabilities associated with the assets transferred to us and occurring or existing before the closing date of December 7, 2005.

Air Emissions

Our operations are subject to the federal Clean Air Act 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 believe that we are in substantial compliance with these requirements. 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. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

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, referred to as CERCLA or 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. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. 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, referred to as RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA s hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease, and our predecessor has in the past owned or leased, properties where 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, 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 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 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, 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.

Title to Properties and Rights-of-Way

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.

Employees

DCP Midstream GP, LLC or its affiliates employs nine people directly and approximately 55 people through DEFS who provide direct support for our operations. 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, available free of charge through our website, http://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 http://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 adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Related to Our Business

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

In order to make our cash distributions at our initial distribution rate of $0.35 per common unit per complete quarter, or $1.40 per unit per year, we require available cash of approximately $6.25 million per quarter, or $25.0 million per year, based on the common units and subordinated units currently outstanding. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at the initial distribution rate under our cash distribution policy. 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, NGLs, and condensate;
- the volume of natural gas we gather, treat, compress, process, transport and sell, and the volume of NGLs we transport and sell;
- the relationship between natural gas and NGL prices;
- the level of competition from other midstream energy companies;
- 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 of 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; and
- the amount of cash reserves established by our general partner.

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.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be 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, which are dependent on certain factors beyond our control. Any decrease in supplies of natural gas or NGLs could adversely affect our business and operating results.

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 attract new customers to our assets include: (1) the level of successful drilling activity near these systems and (2) 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 NYMEX daily settlement price of natural gas has increased from $4.10 per MMBtu as of June 30, 2000 to $8.59 per MMBtu as of December 31, 2005. If the high price for natural gas were to decline, the level of drilling activity could decrease. A sustained

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decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering and pipeline transportation systems and our natural gas treating and processing plants, which would lead to reduced utilization of these assets. Other factors that impact production decisions include producers capital budgets, the ability of producers to obtain necessary drilling and other governmental permits, and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to you.

The cash flow from our Natural Gas Services segment is affected by natural gas, NGL and condensate prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units.

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 demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather;
- 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 impact of energy conservation efforts; and
- 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. As of January 1, 2006, we have hedged approximately 80% of our share of anticipated natural gas and NGL commodity price risk associated with these arrangements through 2010. Additionally, as part of our gathering operations, we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices. As of January 1, 2006, we have hedged approximately 80% of our share of anticipated condensate commodity price risk through 2010. For additional information regarding our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operation Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

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

As of January 1, 2006, we have hedged approximately 80% of our expected natural gas and NGL commodity price risk relating to our percentage of proceeds gathering and processing contracts through 2010 by entering into derivative financial instruments relating to the future price of natural gas and crude oil. In addition, as of January 1, 2006 we have hedged approximately 80% of our expected condensate commodity price risk relating to condensate recovered from our gathering operations through 2010 by entering into derivative financial instruments relating to the future price of crude oil. The intent of these arrangements is to reduce the volatility in our cash flows resulting from fluctuations in commodity prices.

For periods after 2010, our management will evaluate whether to enter into any new hedging arrangements, but there can be no assurance that we will enter into any new hedging arrangement or that our future hedging arrangements will be on terms similar to our existing hedging arrangements. Also, we may seek in the future to further limit our exposure to changes in natural gas, NGL and condensate commodity prices and we may seek to limit our exposure to changes in interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent we hedge our commodity price and interest rate risk, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

Despite our hedging program, we remain 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 hedging 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. 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 unhedged 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, resulting in a reduction of our liquidity.

As a result of these factors, our hedging 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 cash flows. In addition, even though our management monitors our hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, or our hedging policies and procedures are not properly followed or do not work as planned. We cannot assure you that the steps we take to monitor our hedging activities will detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. For additional information regarding our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operation Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

We typically do not obtain independent evaluations of natural gas reserves dedicated to our gathering and pipeline systems; therefore, volumes of natural gas on our systems in the future could be less than we anticipate.

We typically do not obtain independent evaluations of natural gas reserves connected to our systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the total reserves or estimated life of 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. A decline in the volumes of natural gas on our systems could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to you.

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We depend on certain natural gas producer customers for a significant portion of our supply of natural gas and NGLs. The loss of any of these customers could result in a decline in our volumes, revenues and cash available for distribution.

We rely on certain natural gas producer customers for a significant portion of our natural gas and NGL supply. Our two largest suppliers for the year ended December 31, 2005, Anadarko Petroleum Corporation and ConocoPhillips, accounted for approximately 28% and 20%, respectively, of our 2005 natural gas supply in our Natural Gas segment. Our largest NGL supplier, an affiliate of The Williams Companies, Inc., accounted for approximately 77% of our NGL supply for the year ended December 31, 2005 in our NGL Logistics segment. 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, results of operations and financial condition, unless we were able to acquire comparable volumes from other sources.

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 or cause us to pay a higher price than we might otherwise pay. In addition, DEFS and its affiliates are not restricted from competing with us. DEFS 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.

We may not successfully balance our purchases and sales of natural gas, which would increase our exposure to commodity price risks.

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. 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.

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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 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 (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 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.

If third-party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities become unavailable to transport or produce natural gas and NGLs, our revenues and cash available for distribution could be adversely affected.

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. For example, the volumes of NGLs that are transported on our Seabreeze pipeline and the Black Lake pipeline are dependent upon a number of processing plants and NGL pipelines owned and operated by DEFS and other third parties, including Williams Markham Gas Plant, Enterprise Products Matagorda Plant, TEPPCO Partners, L.P. s South Dean NGL pipeline, Regency Intrastate Gas, LLC s Dubach processing plant and Chesapeake Energy Corporation s Black Lake processing plant. In addition, our PELICO pipeline system is interconnected to several third-party intrastate and interstate pipelines, including pipelines owned by Southern Natural Gas Company, Texas Gas Transmission, LLC, CenterPoint Energy Mississippi River Transmission Corporation, Texas Eastern Transmission LP, CenterPoint Energy Gas Transmission Company, Crosstex LIG, LLC, Gulf South Pipeline Company, Tennessee Natural Gas Company and Regency Intrastate Gas, LLC. Since we do not own or operate any of these pipelines or other facilities, their continuing operation is not within our control. If any of these third-party pipelines and other facilities become unavailable to transport or produce natural gas and NGLs, our revenues and cash available for distribution could be adversely affected. For example, throughput for our Seabreeze pipeline was negatively impacted by a shut down of a third party NGL pipeline from March 2004 until June 2005 due to pipeline integrity repairs, which have now been completed.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

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 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. In addition, our customers who are significant producers of natural gas may develop their own gathering, processing and transportation systems in lieu of using ours. Likewise, our customers who produce NGLs may develop their own systems to transport NGLs in lieu of using ours. 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. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to you.

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, which may cause our revenues to decline and operating expenses to increase.

Our natural gas gathering and intrastate transportation operations are generally exempt from Federal Energy Regulatory Commission, or FERC, regulation under the Natural Gas Act of 1938, or NGA, except for Section 311 as discussed below, 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 you 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, in such a circumstance, the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based 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 is subject to FERC regulation under Section 311 of the Natural Gas Policy Act, or 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 PELICO system is obligated to make a new rate filing in 2006, at which time the rates, terms and conditions of the PELICO system s Section 311 transportation services may be subject to change. 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. For more information regarding regulation of our operations, please read Business Regulation of Operations.

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. Please read Business Regulation of Operations.

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 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 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 these costs from insurance or from indemnification from DEFS. Please read Business Environmental Matters.

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

Pursuant to the Pipeline Safety Improvement Act of 2002, the United States Department of Transportation (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.

We currently estimate that we will incur costs of approximately $6.1 million between 2006 and 2010 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. While DEFS has agreed to indemnify us for certain repair costs relating to the Black Lake pipeline and our Seabreeze pipelines resulting from such testing program, the actual costs of making such repairs, including any lost cash flows resulting from shutting down our pipelines 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. According, 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 plan 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 on competitive terms, there can be no assurance that we will in fact be able to enter into such arrangements on favorable terms in the future.

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Our construction of new assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through the construction of new midstream assets. The construction of additions or modifications to our existing systems, and the construction of new midstream assets involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule or at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a new pipeline, the construction may occur over an extended period of time, and we will not receive any material increases in revenues until the project is completed. Moreover, 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. In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

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

Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are: (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms, or (3) outbid by competitors, then our future growth and ability to increase distributions will be limited. 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.

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

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to integrate successfully 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;
- 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 you 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.

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Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our operations and cash flows available for distribution to our unitholders.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are therefore subject to the possibility of 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 on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions to you.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

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

- damage to pipelines and plants, 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, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our 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. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition. In addition, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially, and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

Our costs may increase in the event that our credit obligations under hedging and other contractual arrangements are not guaranteed by DEFS.

DEFS has provided a guaranty to the third party counterparties for the financial hedging arrangements that we have entered into for the purpose of hedging our exposure to fluctuations in commodity prices through late 2010. DEFS is only required to maintain its credit support for our obligations related to derivative financial instruments, such as commodity price hedging contracts, that are in effect as of the closing of our initial public offering as of December 7, 2005 until the earlier to occur of the fifth anniversary of the closing of our initial public offering or such time as we obtain an investment grade credit rating from either Moody s Investor Services, Inc. or Standard & Poor s Ratings Group. As a result, we anticipate that DEFS will not provide a guaranty of any replacement hedging arrangements after the termination of the hedging arrangements that we have contracted to be in place through late 2010. In such event, we would expect that it could be more costly for us to manage our commodity price risk through certain types of financial hedging arrangements unless we are able to achieve creditworthiness at that time similar to the current creditworthiness of DEFS. As a result, we anticipate that as these commercial arrangements expire or are renewed or replaced by new commercial arrangements, DEFS would not continue to provide credit support. In such event, we may need to provide our own credit support arrangements, which may increase our costs. DEFS is under no obligation to provide any new or additional credit support to us.

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

As of December 7, 2005, we entered into a credit facility, consisting of a $100.1 million collateralized term loan facility and a $250 million revolving credit facility for working capital and other general partnership purposes. We had outstanding balances of $100.1 million under the term loan facility and $110.0 million under the revolving credit facility as of December 31, 2005. The term loan facility maximum borrowing is $100.1 million, and once repaid such amount may not be reborrowed. However, once a portion of the term loan is repaid, the revolving credit facility will increase ratably. We continue to have the ability to incur additional debt, subject to limitations in 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;

- we will need a portion of our cash flow to make interest payments on our debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders;

- 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 service our 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, some of which are beyond our control. In addition, our ability to service debt under our revolving credit facility will depend on market interest rates, since we anticipate that the interest rates applicable to our borrowings will fluctuate with movements in interest rate markets. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to 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. We may consider entering into interest rate hedging transactions, the affect of which would be to effectively lock the floating interest rate for the period of the hedge. In February 2006, the board of directors approved management to hedge up to 85% of outstanding floating rate debt. As of March 1, 2006, no interest rate swaps have been executed.

Restrictions in our credit facility will limit our ability to make distributions to you 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. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Requirements.

Increases in interest rates, which have recently experienced record lows, could adversely impact our unit price and our ability to issue additional equity to make acquisitions, incur debt or for other purposes.

The credit markets recently have experienced 50-year record lows in interest rates. As the overall economy strengthens, it is likely that monetary policy will continue to tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. 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 have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, incur debt or for other purposes.

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

We rely on the revenues generated from our midstream energy businesses, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas, NGLs and condensate. Furthermore, all of our assets are located in northern Louisiana, southern Arkansas and eastern Texas. Due to our lack of diversification in industry type and location, an adverse development in one of these businesses or operating areas would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets and operating areas.

We are exposed to the credit risks of our key producer customers, and any material nonpayment or nonperformance by our key producer customers 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. Any material nonpayment or nonperformance by our key producer customers could reduce our ability to make distributions to our unitholders. Furthermore, some of our producer customers 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, and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities in the Middle East or other 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 and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

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Risks Inherent in an Investment in Us

DEFS controls our general partner, which has sole responsibility for conducting our business and managing our operations. DEFS has conflicts of interest, which may permit it to favor its own interests to your detriment.

DEFS owns and controls our general partner. Some of our general partner s directors, and some of its executive officers, are directors or officers of DEFS or its parents. Therefore, conflicts of interest may arise between DEFS and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. 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 DEFS to pursue a business strategy that favors us. DEFS directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of DEFS, 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 DEFS and its affiliates, in resolving conflicts of interest;

- DEFS and its affiliates, including Duke Energy and ConocoPhillips, are not limited in their ability to compete with us. Please read DEFS and its affiliates are not limited in their ability to compete with us below;

- 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 DEFS who provide services to us also will devote significant time to the business of DEFS, and will be compensated by DEFS 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.

DEFS 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 between us, DEFS and others will prohibit DEFS and its affiliates, including Duke Energy and ConocoPhillips, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, DEFS and its affiliates, including Duke 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 substantial and will reduce our cash available for distribution to you.

Pursuant to the Omnibus Agreement we entered into with DEFS, our general partner and others upon the closing of our initial public offering, DEFS 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 substantial and will reduce the amount of cash available for distribution to unitholders. Please read Certain Relationships and Related Transactions Omnibus Agreement. 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. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

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

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, DEFS. 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.

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, 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 DCP Midstream GP, LLC will be chosen by the members of DCP Midstream GP, LLC. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove 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 cannot initially remove our general partner without its consent.

The unitholders will be unable initially to remove our general partner without its consent because our general partner and its affiliates owned sufficient units upon completion of our initial public offering 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. Following the closing of our initial public offering, our general partner and its affiliates owned an approximate 42% 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.

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 or DCP Midstream GP, LLC from transferring all or a portion of their respective ownership interest in our general partner or DCP Midstream GP, LLC to a third party. The new owners of our general partner or DCP Midstream GP, LLC would then be in a position to replace the board of directors and officers of DCP Midstream GP, LLC with its own choices and thereby influence the decisions taken by the board of directors and officers.

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

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

- our unitholders 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.

Affiliates of our general partner may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

DEFS and its affiliates hold an aggregate of 7,143 common units and 7,142,857 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period, as set forth in our partnership agreement, and some may convert earlier. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require you to sell your 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, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. Our general partner and its affiliates own less than 1% of our outstanding common units. At the expiration of the subordination period, assuming no additional issuances of common units, our general partner and its affiliates will own approximately 40% of our outstanding common 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.

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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 you 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.

We will incur increased costs as a result of being a publicly-traded company.

We have limited history operating as a publicly-traded company. As a publicly-traded company, we will incur significant legal, accounting and other expenses that we did not incur as a private company. In addition, the Sarbanes-Oxley Act of 2002, as well as new rules subsequently implemented by the SEC and the New York Stock Exchange, have required changes in corporate governance practices of publicly-traded companies. We expect these new rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly-traded company, we are required to have at least three independent directors, create additional board committees and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our publicly-traded company reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for our general partner to obtain director and officer liability insurance and it may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by individual states. If the Internal Revenue Service treats us as a corporation or we become subject to 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

Internal Revenue Service, which we refer to as the IRS, on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and would 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, our treatment 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 so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. If any of these states were to impose a tax on us, the cash available for distribution to the unitholder would be reduced. 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.

An IRS contest of the federal income tax positions we take may adversely affect the market for our common units, 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. 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 the 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 your share of our taxable income even if you 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. Prior distributions to the unitholders in excess of the total net taxable income allocated to them for a common unit, which decreased their tax basis in that common unit, 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. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, 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 foreign 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 and will be taxable to them. Distributions to non-U.S. persons will be reduced by 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

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taxable income. If the unitholder is a tax-exempt entity or a foreign 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 take 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 your tax returns.

Unitholders may be subject to state and local taxes and return filing requirements.

In addition to federal income taxes, the unitholder will likely 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 do business or own property, even if you do not live in any of those jurisdictions. The unitholder will likely 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 will initially own assets and do business in the States of Louisiana, Texas and Arkansas. Each of these states, other than Texas, currently imposes a personal income tax as well as an income tax on corporations and other entities. Texas imposes a franchise tax (which is based in part on net income) on corporations and limited liability companies. 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 your responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in the common units.

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

We will be considered to have terminated our partnership 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 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

As of February 17, 2006, we operated two processing plants and gathering systems and one pipeline system located in Louisiana and Arkansas within our Natural Gas Services segment, and one pipeline located in Texas within our NGL Logistics segment, all of which are owned by us. In addition, we owned a 45% interest in the Black Lake pipeline within our NGL Logistics segment, which is operated by a third party. For additional details on these plants and pipeline systems, please read Business Natural Gas Services Segment and Business NGL Logistics Segment . We believe that our properties are generally in good condition, well maintained and are generally suitable and adequate to carry on our business at capacity for the foreseeable future.

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

Item 3. ***Legal Proceedings***

We are not a party to any significant legal proceedings but are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Please read Business Regulation of Operations Intrastate Natural Gas Pipeline Regulation and Business Environmental Matters.

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 the fourth quarter of 2005.

Part II

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

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 to be paid for the period from December 7, 2005, the closing of our initial public offering, through December 31, 2005.

Period	High	Low	Distribution per Common Unit	Distribution per Subordinated Unit
December 7, 2005 December 31, 2005	$ 24.92	$ 23.08	$ 0.095	$ 0.095

As of February 17, 2006, there were approximately 30 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 have also issued 7,142,857 subordinated units, 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 units.

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending December 31, 2005, we distribute all of our available cash 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 on hand on the date of determination of available cash for the quarter.

Intent to Distribute the Minimum Quarterly Distribution. We intend to distribute to the holders of common units and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.35 per unit, or $1.40 per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will 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 is existing, 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. Our general partner is entitled to 2% of all quarterly distributions that we make prior to our liquidation. This general partner interest is represented by 357,143 general partner units. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner s initial 2% interest in these distributions will be 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 2% general partner interest.

Our general partner also currently holds rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute in excess of $0.4025 per unit per quarter. The maximum distribution of 50% includes distributions paid to our general partner on its 2% general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on limited partner units that it owns.

On January 25, 2006, we announced the declaration of a cash distribution of $0.095 per unit, payable on February 13, 2006 to unitholders of record on February 3, 2006. That distribution represents the pro rata portion of our minimum quarterly cash distribution of $0.35 per unit for the period December 7, 2005, the closing of our initial public offering, through December 31, 2005.

Sales of Unregistered Units

There were no unregistered units issued during the fourth quarter of 2005.

Purchase of Equity by DCP Midstream Partners, LP

None.

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 contained herein.

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

The following table shows selected financial data of DCP Midstream Partners, LP for the periods and as of the dates indicated. The selected financial data as of December 31, 2005, 2004 and 2003, as well as the selected financial data for the years ended December 31, 2005, 2004, 2003 and 2002, are derived from our audited consolidated financial statements, which include our accounts, and prior to December 7, 2005, the assets, liabilities and operations contributed to us by DEFS and its wholly-owned subsidiaries (DCP Midstream Partners Predecessor) upon the closing of the initial public offering. The selected financial data as

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of December 31, 2001 and for the year ended December 31, 2001 is derived from DCP Midstream Partners Predecessor s unaudited consolidated financial statements.

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.

We derived the information in the following table from DCP Midstream Partners Predecessor and our consolidated financial statements, and that information 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. The table should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations.

	DCP Midstream Partners, LP Year Ended December 31,				
	2005	2004	2003	2002	2001
	($ in millions except per unit data)				
Statements of Operations Data:					
Total operating revenues	$ 784.5	$ 509.5	$ 475.1	$ 297.2	$ 347.9
Operating costs and expenses:					
Purchases of natural gas and NGLs	709.3	452.6	430.6	256.8	304.1
Operating and maintenance expense	14.2	13.6	15.0	14.0	13.3
Depreciation and amortization expense	11.7	12.6	12.8	12.3	11.3
General and administrative expense	11.4	6.5	7.1	6.1	5.6
Total operating costs and expenses	746.6	485.3	465.5	289.2	334.3
Operating income	37.9	24.2	9.6	8.0	13.6
Earnings from equity method investment	0.4	0.6	0.4	0.5	1.4
Impairment of equity method investment		(4.4)			
Interest income	0.5				
Interest expense	(0.8)				
Net income	$ 38.0	$ 20.4	$ 10.0	$ 8.5	$ 15.0
Less:					
Net income attributable to DCP Midstream Partners Predecessor	(33.3)	(20.4)	(10.0)	(8.5)	(15.0)
General partner interest in net income	(0.1)				
Net income allocable to limited partners	$ 4.6	$	$	$	$
Net income per limited partner unit-basic and diluted	$ 0.20	$	$	$	$
Distributions paid	$	$	$	$	$
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 168.9	$ 172.0	$ 181.9	$ 193.5	$ 187.2

Total assets	$ 407.3	$ 241.1	$ 239.5	$ 249.3	$ 232.2
Accounts payable	$ 87.0	$ 39.8	$ 35.5	$ 26.0	$ 15.7
Long-term debt	$ 210.1	$	$	$	$
Partners equity	$ 100.9	$ 198.4	$ 201.1	$ 220.7	$ 211.1

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 Duke Energy Field Services, LLC and its wholly-owned subsidiaries upon the closing of our initial public offering as DCP Midstream Partners Predecessor.

Overview

We are a Delaware limited partnership recently formed by Duke Energy Field Services, LLC (DEFS) to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We operate two business segments:

- our Natural Gas Services segment, which consists of our North Louisiana natural gas gathering, processing and transportation system; and
- our NGL Logistics segment, which consists of our interests in two NGL pipelines.

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, DEFS retained a 5% interest and we own a 45% interest in Black Lake.

Factors That Significantly Affect Our Results

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 volume. Throughput volumes and capacity utilization rates generally are driven by wellhead production and our competitive position on a regional basis and more broadly by demand for natural gas, NGLs and condensate.

Our results of operations for our Natural Gas Services segment are also impacted by the fees we receive and the margins we generate. Our processing contract arrangements can have a significant impact on our profitability. Because of the volatility of the prices for natural gas, NGLs and condensate, as of January 1, 2006 we have hedged approximately 80% of our commodity price risk associated with our gathering and processing arrangements through 2010 with natural gas and crude oil swaps. With these swaps, we have substantially reduced our exposure to commodity price movements with respect to those volumes under these types of contractual arrangements for this period. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies. Actual contract terms will be based upon a variety of factors, including natural gas quality, geographic location, the competitive commodity and 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 some types of contracts are more common and other market factors.

In addition, during the fourth quarter of 2005, we were able to benefit 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.

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

Upon the closing of our initial public offering, DEFS contributed to us the assets, liabilities and operations reflected in the historical financial statements other than the accounts receivable of DCP Midstream Partners Predecessor and a 5% interest in Black Lake, which were not contributed to us. The historical financial statements of DCP Midstream Partners Predecessor do not give effect to various items that will affect our results of operations and liquidity following the closing of our initial public offering, including the items described below:

- the indebtedness we incurred at the closing of our initial public offering increased our interest expense from the interest expense reflected in our historical financial statements;

- we have entered into long-term hedging arrangements for approximately 80% of our expected natural gas, NGL and condensate commodity price risk relating to our gathering and processing arrangements through 2010; and

- we anticipate initially incurring approximately $8.4 million annually, some of which will be allocated to us by DEFS, of additional general and administrative expenses relating to operating as a separate publicly held limited partnership, including compensation and benefit expenses of our executive management personnel, costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation.

In addition, our results of operations for the year ended December 31, 2005 benefited from higher throughput volumes in our Seabreeze pipeline as a result of the completion of pipeline integrity repairs on a third party NGL pipeline in mid-2005. As a result of pipeline integrity testing that is scheduled for 2006, we anticipate experiencing lower volumes and increased repair costs on the Seabreeze pipeline. The Black Lake pipeline is currently experiencing increased operating costs due to pipeline integrity testing that commenced in 2005 and will continue into 2007. We expect that our results of operations related to our non-controlling interest in the Black Lake pipeline will benefit in 2007 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. DEFS 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 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.

Finally, we intend to make cash distributions to our unitholders and our general partner at an initial distribution rate of $0.35 per common unit per quarter ($1.40 per common unit on an annualized basis). 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 commercial borrowings and other debt and common unit issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs.

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 high 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 liquified 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 as a result of recent high natural gas prices, 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. Drilling activity generally decreases as natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations.

Processing Margins. During 2005, our overall processing margin benefited from rising natural gas, NGL and condensate prices, primarily as a result of our percentage-of-proceeds contracts which perform better in the current natural gas, NGL and condensate price environment. 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 exposure to commodity price movements for these commodities by entering into hedging arrangements in September 2005, which were effective as of January 1, 2006, for approximately 80% of our currently anticipated natural gas, NGL and condensate price risk associated with our percentage-of-proceeds arrangements and gathering operations through 2010. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

Hurricanes Katrina and Rita. Hurricanes Katrina and Rita caused extensive damage to the Texas, Louisiana and Mississippi Gulf Coast in late August and mid-September of 2005. These storms did not cause any significant damage to our properties; however, these storms have negatively affected the nation s short term energy supply, resulting in natural gas and NGL prices increasing significantly in the fourth quarter of 2005. We do not expect any supply or pricing changes that resulted from these hurricanes to have an adverse impact on our results of operations.

Impact of Inflation. Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the five-year period ended December 31, 2005. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. 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 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 margins for our Natural Gas Services segment principally under the following types of contractual 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. 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, which specified amount is generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. Revenues associated with these arrangements may be included as sales of natural gas, NGLs and condensate or transportation and processing services. The revenue we earn is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a

decline in volumes, however, our revenues from these arrangements would be reduced.

Percentage-of-proceeds arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, transport the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs at index prices based on published index market prices. 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. Under these types of arrangements, our revenues correlate directly with the price of natural gas and NGLs.

As of January 1, 2006, we have hedged approximately 80% of our currently anticipated natural gas and NGL commodity price risk associated with the percentage-of-proceeds arrangements through 2010 with natural gas and crude oil swaps. With these swaps, we expect our exposure to commodity price movements to be substantially reduced. Additionally, as part of our gathering operations, we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices. As of January 1, 2006, we have hedged approximately 80% of our currently anticipated condensate price risk through 2010 with crude oil swaps. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

We also purchase a small portion of our natural gas under percentage-of-index arrangements. Under percentage-of-index arrangements, we purchase natural gas from the producers at the wellhead at a price that is either at a fixed percentage of the index price for the natural gas that they produce or at an index based price less a fixed fee to gather, compress, treat and/or process their natural gas. We then gather, compress treat and/or process the natural gas and then sell the residue natural gas and NGLs at index related prices. Under these types of arrangements, our costs to purchase the natural gas from the producer is based on the price of natural gas. As a result, our gross margin under these arrangements increases as the price of NGLs increases relative to the price of natural gas, and our gross margin under these arrangements decreases as the price of natural gas increases relative to the price of NGLs.

The natural gas supply for the gathering pipelines and processing plants in our North Louisiana system is derived primarily from natural gas wells located in five parishes in northern Louisiana. The PELICO system also receives natural gas produced in east Texas through its interconnect with other pipelines that transport natural gas from east Texas into western Louisiana. This five parish area has experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. Our primary suppliers of natural gas to the North Louisiana system are Anadarko Petroleum Corporation and ConocoPhillips (one of our affiliates), which collectively represented approximately 48% of the 355 MMcf/d of natural gas supplied to this system in 2005. 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, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. In addition, under our merchant arrangements, we use a subsidiary of DEFS (Duke Energy Field Services Marketing, LP) as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties. We also have entered into a contractual arrangement with a subsidiary of DEFS (Duke Energy Field Services Marketing, LP) that provides that DEFS will purchase natural gas and transport it into our PELICO system where we will buy the gas from DEFS at their weighted average cost plus a contractually agreed to marketing fee. In addition, for a significant portion of the gas that we sell out of our PELICO system, we have entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase that natural gas from us and transport it to a sales point at a price equal to their net weighted average sales price less a contractually agreed to marketing fee. 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 account for such a physical fixed price transaction and the related financial derivative as a fair value hedge. 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.

The NGLs extracted from the natural gas at the Minden processing plant are sold at market index prices to an affiliate of DEFS and transported to the Mont Belvieu hub via the Black Lake pipeline. The NGLs extracted from the natural gas at the Ada processing plant are sold at market index prices to third parties and are delivered to the third parties trucks at the tailgate of the plant.

NGL Logistics Segment

Historically, we have gathered and transported NGLs either under fee-based transportation contracts or through purchasing the NGLs at the inlet of the pipeline and selling the NGLs at the outlet. In conjunction with our formation, we entered into a contractual arrangement with DEFS that requires DEFS to purchase the NGLs that were historically purchased by us, and to pay us to transport the NGLs pursuant to a fee-based rate that is applied to the volumes transported. We 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.

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. We will 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 pipeline, 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 natural gas processed 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 measurements are non-Generally Accepted Accounting Principles (non-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 may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

Volumes. We view throughput volumes on our North Louisiana system and the Seabreeze and Black Lake pipelines 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 the North Louisiana system s 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 Seabreeze pipeline and the Black Lake pipeline 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 the NGL pipelines. We regularly monitor producer activity in the areas served by the North Louisiana system and the Seabreeze and Black Lake 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 and natural gas liquids, and we define segment gross margin for each segment as total operating revenues for that segment less purchases of natural gas and natural gas liquids 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.

With respect to our Natural Gas Services segment, we calculate our gross margin as our total operating revenue for this segment less natural gas and NGL purchases. Operating revenue consists of sales of natural gas, NGLs and condensate resulting from our gathering, compression, treating, processing and transportation activities, fees associated with the gathering of natural gas, and any gains and losses realized from our non-trading derivative activity related to our natural gas asset-based marketing. Purchases include the cost of natural gas and NGLs purchased by us. Our gross margin is impacted by our contract portfolio. We purchase the wellhead natural gas from the producers under fee-based arrangements, percentage-of-proceeds arrangements or percentage-of-index arrangements. Our gross margin generated from percentage-of-proceeds gathering and processing contracts is directly correlated to the price of natural gas and NGLs. Under percentage-of-index arrangements, our gross margin is adversely affected when the price of NGLs falls in relation to the price of natural gas. Generally, our contract structure allows for us to allocate fuel costs and other measurement losses to the producer or shipper and, therefore, does not impact gross margin. Additionally, as part of our gathering operations, we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices.

	Year Ended December 31,		
Reconciliation of Non-GAAP Measures	**2005**	**2004**	**2003**
	($ in millions)		
Reconciliation of *gross margin* to net income:			
Net income	$ 38.0	$ 20.4	$ 10.0
Less:			
Interest income	0.5		
Earnings from equity method investment	0.4	0.6	0.4
Add:			
Interest expense	0.8		
Impairment of equity method investment		4.4	
Operating and maintenance expense	14.2	13.6	15.0
Depreciation and amortization expense	11.7	12.6	12.8
General and administrative expense	11.4	6.5	7.1

Gross margin	$ 75.2	$ 56.9	$ 44.5

Reconciliation of Non-GAAP Measures	2005	2004	2003
	Year Ended December 31, ($ in millions)		
Reconciliation of ***segment gross margin*** **to segment net income:**			
Natural Gas Services segment:			
Net income	$ 46.6	$ 28.5	$ 15.6
Add: Depreciation and amortization expense	10.8	11.7	11.9
Operating and maintenance expense	14.0	13.4	14.7
Segment gross margin	$ 71.4	$ 53.6	$ 42.2
NGL Logistics segment:			
Net income (loss)	$ 3.1	$ (1.6)	$ 1.5
Add:			
Depreciation and amortization expense	0.9	0.9	0.9
Operating and maintenance expense	0.2	0.2	0.3
Impairment of equity method investment		4.4	
Less: Earnings from equity method investment	(0.4)	(0.6)	(0.4)
Segment gross margin	$ 3.8	$ 3.3	$ 2.3

Operating and Maintenance Expense 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, 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 slightly depending on the activities performed during a specific period.

In addition, we also review our general and administrative expense, a substantial amount of which is incurred through DEFS and allocated to us. For the year ended December 31, 2005, our general and administrative expense was $11.4 million, which included directly incurred costs as a result of our initial public offering for audit, legal, printing and insurance fees. Under our Omnibus Agreement with DEFS, we will reimburse DEFS up to $4.8 million for 2006, for the provision by DEFS or its affiliates of various general and administrative services to us. This allocated general and administrative expense relates to the assets being contributed to us at the closing of our initial public offering. For the two years following the first year after our initial public offering, the fee shall be increased by the percentage increase 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 our special committee. We will also be obligated to reimburse DEFS for our allocable share of insurance expenses related to our businesses and properties as well as insurance expenses related to director and officer liability coverage. We expect that our allocable share of these insurance expenses will be approximately $1.2 million in 2006.

We anticipate initially incurring approximately $8.4 million annually of general and administrative expense, some of which will be allocated to us by DEFS, associated with being a separate publicly held limited partnership. These public limited partnership expenses are related to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included in the public limited partnership expenses are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and director compensation.

EBITDA. We define EBITDA as net income plus net interest 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 credit agreement) of not more than 4.75 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, not more than 5.25 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 credit agreement) of greater than or equal to 3.0 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination. Our EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA in the same manner.

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

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing methods or capital structure; and
- the 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.

Reconciliation of Non-GAAP Measures	Year Ended December 31, 2005	2004	2003
	($ in millions)		
Reconciliation of net income to *EBITDA*:			
Net income	$ 38.0	$ 20.4	$ 10.0
Add:			
Interest expense, net	0.3		
Depreciation and amortization expense	11.7	12.6	12.8
EBITDA	$ 50.0	$ 33.0	$ 22.8
Reconciliation of cash provided by operating activities to *EBITDA*:			
Cash provided by operating activities	$ 75.5	$ 25.6	$ 30.8
Net changes in working capital accounts, including net changes in price risk management assets and liabilities	(26.2)	11.2	(7.8)
Non-cash impairment of equity method investment		(4.4)	
Other, including changes in noncurrent assets and liabilities	0.4	0.6	(0.2)
Interest expense, net	0.3		
EBITDA	$ 50.0	$ 33.0	$ 22.8

Distributable Cash Flow. We define distributable cash flow as EBITDA, less maintenance capital expenditures and net interest expense (see Liquidity and Capital Resources for further definition of maintenance capital expenditures). Distributable cash flow is used as a supplemented financial measure by our

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management and by external users of our financial statements, such as investors, commercial banks, research analysts and other, to assess our ability to make cash distributions to our unitholders and our general partner.

Reconciliation of Non-GAAP Measures	**Year Ended December 31, 2005**	**2004**	**2003**
	($ in millions)		
Reconciliation of cash provided by operating activities to *distributable cash flow*:			
Cash provided by operating activities	$ 75.5	$ 25.6	$ 30.8
Adjustments to cash provided by operating activities to derive distributable cash flow:			
Maintenance capital expenditures	(3.3)	(1.9)	(1.3)
Earnings from equity method investment	(0.4)	(0.6)	(0.4)
Distributions from equity method investment			0.6
Net changes in working capital accounts, including net changes in price risk management assets and liabilities	(26.2)	11.2	(7.8)
Non-cash impairment of equity method investment		(4.4)	
Other, including changes in noncurrent assets and liabilities	0.4	0.6	(0.2)
Distributable cash flow	$ 46.0	$ 30.5	$ 21.7

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.

Revenue Recognition Our primary types of sales and service activities reported as operating revenue include:

- sales of natural gas, NGLs and condensate;
- natural gas gathering, processing and transportation, from which we generate revenues primarily through the compression, gathering, treating, processing and transportation of natural gas; and
- NGL transportation from which we generate revenues from transportation fees.

Revenues associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenues associated with transportation and processing are recognized when the service is provided.

For gathering services, we receive fees from natural gas producers to transport the natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, we are paid for our services by keeping a percentage of the NGLs produced and the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, we purchase wellhead natural gas and sell processed natural gas and NGLs to third parties.

We recognize revenues for non-trading derivative activity net in the consolidated statements of operations as (losses) gains from non-trading derivative activity, in accordance with EITF Issue No. 02-03, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.* These activities include mark-to-market gains and losses on energy derivative contracts and the financial or physical settlement of energy derivative contracts.

We generally report revenues gross in the consolidated statements of operations, in accordance with EITF Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent.* Except for fee-based arrangements, we act as the principal in these transactions, take title to the product, and incur the risks and rewards of ownership.

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

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

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

Impairment of Equity Method Investment We evaluate our equity method investment for impairment when events or changes in circumstances indicate, in management s judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. Management assesses the fair value of our equity method investment using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment.

Accounting for Risk Management and Hedging Activities and Financial Instruments Each derivative not qualifying for the normal purchases and normal sales exception under Statement of Financial Accounting Standards No. 133, or SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* as amended, is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on non-trading derivative and hedging transactions. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging transactions at fair value until the contractual settlement period occurs.

All derivative activity reflected in the combined financial statements was transacted by us and DEFS and its subsidiaries prior to our initial public offering and was transferred and/or allocated to us for periods prior to December 7, 2005. All derivative activity reflected in the consolidated financial statements from December 7, 2005 and going forward has been and will be transacted by us. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activity, are designated as non-trading derivative activity. For the periods presented, we did not have any trading activity, however, we do have cash flow and fair value hedge activity, normal purchases and normal sales activity, and non-trading derivative activity included in the consolidated financial statements. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

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

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

(b) Hedge method An accounting method whereby the effective portion of the change in the fair value of the asset or liability is recorded as a balance sheet adjustment and there is no recognition in the results of operations for the effective portion until the service is provided or the associated delivery period occurs.

(c) Accrual method An accounting method whereby there is no recognition in the results of operations for changes in fair value of a contract until the service is provided or the associated delivery period occurs.

Cash Flow and Fair Value Hedges For derivatives designated as a cash flow hedge or a fair value hedge, management prepares formal documentation of the hedge in accordance with SFAS 133. In addition, management formally assesses, both at the inception of the hedge and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on non-trading derivative and hedging transactions. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in partners equity as accumulated other comprehensive income, or AOCI, and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction occurs, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction occurs, unless it is no longer probable that the hedged transaction will occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

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

Valuation When available, quoted market prices or prices obtained through external sources are used to verify 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.

Natural Gas and NGL Imbalance Accounting Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system. These imbalances are settled with deliveries of natural gas or NGLs or with cash.

Accounting for Equity-Based Compensation We adopted a long-term incentive plan which permits for the grant of units as described further in Note 2 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. The expense related to this equity based compensation is accounted for using estimates of the percentage of equity that will vest at the end of the incentive period. These estimates are based on the projected performance of our equity during the incentive period. If actual results are not consistent with our assumptions and judgments, we may be exposed to changes in compensation expense that could be material.

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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, 2005. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year Ended December 31,		
	2005	2004	2003
	($ in millions except operating data)		
Operating revenues:			
Sales of natural gas, NGLs and condensate	$ 762.3	$ 489.7	$ 454.0
Transportation and processing services	22.9	19.9	18.6
(Losses) gains from non-trading derivative activity	(0.7)	(0.1)	2.5
Total operating revenues	784.5	509.5	475.1
Purchases of natural gas and NGLs	709.3	452.6	430.6
Gross margin(a)	75.2	56.9	44.5
Operating and maintenance expense	14.2	13.6	15.0
General and administrative expense	11.4	6.5	7.1
Earnings from equity method investment(c)	(0.4)	(0.6)	(0.4)
Impairment of equity method investment(c)		4.4	
EBITDA(b)	50.0	33.0	22.8
Depreciation and amortization expense	11.7	12.6	12.8
Interest income	(0.5)		
Interest expense	0.8		
Net income	$ 38.0	$ 20.4	$ 10.0
Segment financial and operating data:			
Natural Gas Services Segment			
Financial data:			
Gross margin(a)	$ 71.4	$ 53.6	$ 42.2
Operating data:			
Natural gas throughput (MMcf/d)	356	328	348
NGL gross production (Bbls/d)	4,543	4,690	4,381
NGL Logistics Segment			
Financial data:			
Gross margin(a)	$ 3.8	$ 3.3	$ 2.3
Operating data:			
Seabreeze throughput (Bbls/d)	15,797	14,966	14,685
Black Lake throughput (Bbls/d)(c)	4,768	5,256	5,547

(a) Gross margin consists of total operating revenues less purchases of natural gas and NGLs and segment gross margin for each segment consists of total operating revenues for that segment less purchases of natural gas and NGLs for that segment. Please read How We Evaluate Our Operations on page 44.

(b) EBITDA consists of net income plus depreciation and amortization expense. Please read How We Evaluate Our Operations on page 44.

(c) Represents 50% of the throughput volumes and earnings of Black Lake in 2003, 2004 and the period from January 1, 2005 through December 6, 2005. Upon closing of our initial public offering on December 7, 2005, DEFS retained a 5% interest in Black Lake. We own a 45% interest in Black Lake.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues Total operating revenues increased $275.0 million, or 54%, to $784.5 million in 2005 from $509.5 million in 2004. This increase was primarily due to the following factors:

$239.5 million increase attributable primarily to higher commodity prices and natural gas sales volumes for our Natural Gas Services segment;

$35.5 million increase primarily attributable to higher NGL prices and increased throughput for our Seabreeze pipeline.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased $256.7 million, or 57%, to $709.3 million in 2005 from $452.6 million in 2004. This increase was primarily due to the following factors:

$221.7 million increase attributable to higher costs of raw natural gas supply driven primarily by higher commodity prices for our Natural Gas Services segment; and

$35.0 million increase attributable to higher NGL prices and increased throughput for our Seabreeze pipeline.

Gross Margin Gross margin increased $18.3 million, or 32%, to $75.2 million in 2005 from $56.9 million in 2004, primarily as a result of the following factors:

$17.8 million increase attributable primarily to higher commodity prices and an increase in marketing activity and increased throughput across the PELICO system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system for our Natural Gas Services segment. The market conditions causing these significant differences in the natural gas prices at various receipt and delivery points across the PELICO system are unusual and may not continue in the future, and we may not be able to capture the upside related to the market condition in the future; and

$0.5 million increase due to increased throughput volumes for our Seabreeze pipeline.

Impact of Hurricane Katrina and Rita Hurricanes Katrina and Rita caused extensive damage to the Texas, Louisiana and Mississippi Gulf Coast in late August and mid-September of 2005. These storms did not cause any significant damage to our properties. However, in September 2005, we experienced operational disruptions for several days as a result of the impact of Hurricane Rita on the energy industry in our areas of operations. These disruptions reduced our total operating revenues by approximately $10.1 million, our purchases by approximately $9.5 million and our gross margin by approximately $0.6 million in September 2005.

Operating and Maintenance Expense Operating and maintenance expense increased $0.6 million, or 4%, to $14.2 million in 2005 from $13.6 million in 2004. This increase was primarily the result of higher maintenance and pipeline integrity costs for our Natural Gas Services segment.

General and Administrative Expense General and administrative expense increased $4.9 million, or 75%, to $11.4 million in 2005 from $6.5 million in 2004. This increase was primarily the result of public offering costs of approximately $4.0 million and higher allocated costs from DEFS of approximately $0.9 million due to higher overall

DEFS general and administrative costs primarily as a result of increased insurance premiums. Due to general trends in the insurance industry, our property and casualty insurance deductibles have significantly increased in 2006.

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Earnings from Equity Method Investment Earnings from equity method investment decreased $0.2 million, to $0.4 million in 2005 from $0.6 million in 2004. This decrease was primarily due to an increase in Black Lake operating costs as a result of pipeline integrity testing during the fourth quarter of 2005.

Impairment of Equity Method Investment In 2004, we recorded an impairment totaling $4.4 million as impairment of equity method investment, which is included in the NGL Logistics segment.

Depreciation and Amortization Expense Depreciation and amortization expense decreased $0.9 million, or 7%, to $11.7 million in 2005 from $12.6 million in 2004 as a result of an asset that became fully depreciated at the beginning of 2005.

Year Ended December 31, 2004 vs. Year Ended December 31, 2003

Total Operating Revenues Total operating revenues increased $34.4 million, or 7%, to $509.5 million in 2004 from $475.1 million in 2003. This increase was primarily due to the following factors:

- $24.8 million increase attributable primarily to higher commodity prices for our Seabreeze pipeline; and

- $9.6 million increase attributable primarily to higher commodity prices, partially offset by lower sales volumes for our Natural Gas Services segment.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased $22.0 million, or 5%, to $452.6 million in 2004 from $430.6 million in 2003. This increase was primarily due to the following factors:

- $23.8 million increase attributable to higher commodity prices in our Seabreeze pipeline; and

- $1.8 million decrease attributable to lower natural gas throughput in our Natural Gas Services segment, offset by higher raw natural gas supply prices.

Gross Margin Gross margin increased $12.4 million, or 28%, to $56.9 million in 2004 from $44.5 million in 2003, primarily as a result of the following factors:

- $11.4 million increase attributable to percentage-of-proceeds processing arrangements, mainly due to higher commodity prices and improved per unit margin from our PELICO system; and

- $1.0 million increase attributable to higher per unit margins for our Seabreeze pipeline.

Operating and Maintenance Expense Operating and maintenance expense decreased $1.4 million, or 9%, to $13.6 million in 2004 from $15.0 million in 2003. This decrease was primarily the result of lower repairs and maintenance for our Natural Gas Services segment.

General and Administrative Expense General and administrative expense decreased $0.6 million, or 8%, to $6.5 million in 2004 from $7.1 million in 2003. This decrease was primarily the result of lower allocated costs from DEFS due to lower overall DEFS general and administrative costs.

Earnings from Equity Method Investment Earnings from equity method investment increased $0.2 million, to $0.6 million in 2004 from $0.4 million in 2003. This increase was primarily the result of lower Black Lake operating and administrative costs.

Impairment of Equity Method Investment In 2004, we recorded an impairment totaling $4.4 million as impairment of equity method investment, which is included in the NGL Logistics segment.

Depreciation and Amortization Expense Depreciation and amortization expense decreased $0.2 million, or 2%, to $12.6 million in 2004 from $12.8 million in 2003, primarily as a result of certain assets that became fully depreciated at the beginning of 2004.

Results of Operations Natural Gas Services Segment

This segment consists of our North Louisiana system, which includes our PELICO system and our Minden and Ada processing plants and gathering systems.

	Year Ended December 31,		
	2005	2004	2003
	($ in millions except operating data)		
Operating revenues:			
Sales of natural gas, NGLs and condensate	$ 570.9	$ 333.5	$ 322.6
Transportation and processing services	22.6	19.9	18.6
(Losses) gains from non-trading derivative activity	(0.7)	(0.1)	2.5
Total operating revenues	592.8	353.3	343.7
Purchases of natural gas and NGLs	521.4	299.7	301.5
Gross margin(a)	71.4	53.6	42.2
Operating and maintenance expense	14.0	13.4	14.7
Depreciation and amortization expense	10.8	11.7	11.9
Natural Gas Services segment net income	$ 46.6	$ 28.5	$ 15.6
Operating data:			
Natural gas throughput (MMcf/d)	356	328	348
NGL gross production (Bbls/d)	4,543	4,690	4,381

(a) Segment gross margin for each segment consists of total operating revenues for that segment less purchases of natural gas and NGLs for that segment. Please read How We Evaluate Our Operations on page 44.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues Total operating revenues increased $239.5 million, or 68%, to $592.8 million in 2005 from $353.3 million in 2004. This increase was primarily due to the following factors:

$169.6 million increase attributable to an increase in natural gas prices;

$15.0 million increase attributable to an increase in NGL and condensate prices;

$52.8 million increase attributable to higher natural gas sales volumes driven primarily by incremental natural gas demand at our Minden and Ada processing plants related to our merchant arrangements, higher gas supply volumes for our Ada processing plant and gathering system and an increase in marketing activity and increased throughput across the PELICO system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing these significant differences in the natural gas prices at various receipt and delivery points across the PELICO system are unusual and may not continue in the future, and we may not be able to capture the upside related to the market condition in the future;

$2.7 million increase attributable to higher processing fees primarily driven by incremental fee based services of our Ada gathering system and higher transportation fees primarily driven by an increase in volumes on our PELICO system; and

$0.6 million decrease attributable to lower non-trading derivative activity primarily due to natural gas asset-based marketing.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased $221.7 million, or 74%, to $521.4 million in 2005 from $299.7 million in 2004. This increase was primarily due to higher costs of raw natural gas supply driven by higher commodity prices.

Gross Margin Gross margin increased $17.8 million, or 33%, to $71.4 million in 2005 from $53.6 million in 2004, primarily as a result of the following factors:

- $8.7 million increase attributable to higher commodity prices;
- $9.3 million increase attributable to an increase in marketing activity and increased throughput across the PELICO system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing these significant differences in the natural gas prices at various receipt and delivery points across the PELICO system are unusual and may not continue in the future, and we may not be able to capture the upside related to the market condition in the future;
- $2.7 million increase attributable to higher processing fees primarily driven by incremental fee based services of our Ada gathering system and higher transportation fees primarily driven by an increase in volumes on our PELICO system;
- $2.3 million decrease attributable to lower contractual fees charged to customers related to pipeline imbalances and a decrease in NGL recoveries at Minden as a result of unfavorable processing economics in the fourth quarter of 2005; and
- $0.6 million decrease attributable to lower non-trading derivative activity primarily due to natural gas asset-based marketing.

Operating and Maintenance Expense Operating and maintenance expense increased $0.6 million, or 4%, to $14.0 million in 2005 from $13.4 million in 2004. This increase was primarily the result of higher outside services, parts, supplies and labor for maintenance and pipeline integrity testing.

NGL production during 2005 decreased 147 Bbls/d, or 3%, to 4,543 Bbls/d from 4,690 Bbls/d in 2004 due primarily to unfavorable market economics for processing NGLs in the fourth quarter of 2005. Natural gas transported and/or processed during 2005 increased 28 MMcf/d, or 9%, to 356 MMcf/d from 328 MMcf/d in 2004 primarily as a result of higher natural gas volumes for our PELICO system.

Year Ended December 31, 2004 vs. Year Ended December 31, 2003

Total Operating Revenues Total operating revenues increased $9.6 million, or 3%, to $353.3 million in 2004 from $343.7 million in 2003. This increase was primarily due to the following factors:

- $17.0 million increase attributable to higher natural gas prices;
- $12.5 million increase attributable to higher NGL and condensate prices;
- $4.5 million increase attributable to higher NGL sales volume due to favorable market economics for processing NGLs;
- $1.2 million increase attributable to higher transportation and processing fees due primarily to the incremental fee based services of our Ada gathering system offset by gas supply declines;
- $23.1 million decrease attributable to lower natural gas sales volume driven by wellhead gas supply decline and higher NGL recoveries; and

$2.6 million decrease attributable to lower non-trading derivative activity primarily due to natural gas asset-based marketing.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased $1.8 million to $299.7 million in 2004 from $301.5 million in 2003. This decrease was primarily due to the following factors:

$23.3 million decrease attributable to lower raw natural gas supply volume due to declining wellhead production; and

$21.5 million increase attributable to higher costs of raw natural gas supply which is primarily due to higher commodity prices.

Gross Margin Gross margin increased $11.4 million, or 27%, to $53.6 million in 2004 from $42.2 million in 2003, primarily as a result of the following factors:

- $8.0 million increase attributable to percentage-of-proceeds processing arrangements, mainly due to higher commodity prices;
- $2.3 million increase attributable to higher per unit margins for our PELICO system primarily due to higher contractual premiums charged to customers related to pipeline imbalances; and
- $1.2 million increase attributable to higher transportation and processing fees as described above.

NGL production during 2004 increased 309 Bbls/d, or 7%, to 4,690 Bbls/d in 2004 from 4,381 Bbls/d during 2003 as a result of favorable market economics for processing NGLs. Natural gas transported and/or processed during 2004 decreased 20 MMcf/d, or 6%, to 328 MMcf/d from 348 MMcf/d during 2003 as a result of lower natural gas supply.

Operating and Maintenance Expense Operating and maintenance expense decreased $1.3 million, or 9%, to $13.4 million in 2004 from $14.7 million during 2003. This decrease was primarily the result of lower outside services for repairs and maintenance.

Results of Operations NGL Logistics Segment

This segment includes our NGL transportation pipelines, which includes our Seabreeze pipeline and our interest in Black Lake.

	Year Ended December 31,		
	2005	2004	2003
	($ in millions except operating data)		
Operating revenues:			
Sales of NGLs	$ 191.4	$ 156.2	$ 131.4
Transportation and processing services	0.3		
Total operating revenues	191.7	156.2	131.4
Purchases of NGLs	187.9	152.9	129.1
Gross margin(a)	3.8	3.3	2.3
Operating and maintenance expense	0.2	0.2	0.3
Earnings from equity method investment	(0.4)	(0.6)	(0.4)
Impairment of equity method investment		4.4	
Depreciation and amortization expense	0.9	0.9	0.9
NGL Logistics segment net income	$ 3.1	$ (1.6)	$ 1.5
Operating data:			
Seabreeze throughput (Bbls/d)	15,797	14,966	14,685
Black Lake throughput (Bbls/d)(b)	4,768	5,256	5,547

(a) Segment gross margin for each segment consists of total operating revenues for that segment less purchases of natural gas and NGLs for that segment. Please read How We Evaluate Our Operations on page 44.

(b) Represents 50% of the throughput volumes of the Black Lake pipeline in 2003, 2004 and the period from January 1, 2005 through December 6, 2005. Upon closing of our initial public offering on December 7, 2005, DEFS retained a 5% interest in Black Lake. We own a 45% interest in Black Lake.

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Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues Total operating revenues increased $35.5 million, or 23%, to $191.7 million in the 2005 from $156.2 million in 2004. This increase was primarily due to the following factors:

- $39.7 million increase attributable to higher NGL prices for our Seabreeze pipeline;

- $4.5 million decrease attributable to lower sales volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement; and

- $0.3 million increase in transportation revenue attributable to the change in contract terms in December 2005, between DEFS and Seabreeze, from a purchase and redeliver arrangement to a fee-based transport contractual arrangement.

Overall, our Seabreeze pipeline experienced an increase in throughput volumes during 2005 as a result of a temporary disruption in supply from a third-party pipeline in March 2004, which was restored in June 2005.

Purchases of NGLs Purchases of NGLs increased $35.0 million, or 23%, to $187.9 million in 2005 from $152.9 million 2004. The increase was due primarily to the following factors:

- $39.7 million increase attributable to higher NGL prices for our Seabreeze pipeline; and

- $4.7 million decrease attributable to the change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Gross Margin Gross margin increased $0.5 million, or 15%, to $3.8 million in 2005 from $3.3 million in 2004 mainly as a result of higher volumes on our Seabreeze pipeline.

Earnings from Equity Method Investment Earnings from equity method investment decreased $0.2 million, to $0.4 million in 2005 from $0.6 million in 2004. This decrease was primarily due to an increase in Black Lake operating costs as a result of pipeline integrity testing during the fourth quarter of 2005.

Impairment of Equity Method Investment In 2004, we recorded an impairment totaling $4.4 million as impairment of equity method investment. We did not record an impairment in 2005.

Year Ended December 31, 2004 vs. Year Ended December 31, 2003

Total Operating Revenues Total operating revenues increased $24.8 million, or 19%, to $156.2 million in 2004 from $131.4 million in 2003. This increase was primarily due to the following factors:

- $22.3 million increase attributable to higher commodity prices for our Seabreeze pipeline; and

- $2.5 million increase attributable to higher throughput volumes for our Seabreeze pipeline due to additional supply sources.

Purchases of NGLs Purchases of NGLs increased $23.8 million, or 18%, to $152.9 million in 2004 from $129.1 million in 2003. The increase was due primarily to the following factors:

$21.3 million increase attributable to higher NGL prices for our Seabreeze pipeline; and

$2.5 million increase attributable to higher throughput volumes for our Seabreeze pipeline as described above.

Gross Margin Gross margin increased $1.0 million, or 43%, to $3.3 million in 2004 from $2.3 million in 2003 mainly as a result of higher per unit margin for our Seabreeze pipeline driven primarily by our Seabreeze pipeline transporting a larger portion of our volumes under higher margin supply contracts.

Earnings from Equity Method Investment Earnings from equity method investment increased $0.2 million to $0.6 million in 2004 from $0.4 million in 2003. This increase was primarily the result of lower Black Lake operating and administrative costs.

Impairment of Equity Method Investment In 2004, we recorded an impairment totaling $4.4 million as impairment of equity method investment.

Liquidity and Capital Resources

Historically, our sources of liquidity included cash generated from operations and funding from DEFS. Our cash receipts were deposited in DEFS bank accounts and all cash disbursements were made from these accounts. Thus, historically our financial statements have reflected no cash balances. Cash transactions handled by DEFS for us were reflected in partners equity as intercompany advances between DEFS and us. Following our initial public offering, we maintain our own bank accounts, which are managed by DEFS.

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from Black Lake;
- 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 used a portion of our retained $206.4 million from our initial public offering to: 1) purchase $100.1 million of high-grade securities, which were used as collateral to secure the term loan portion of our credit facility, 2) pay approximately $4.0 million of expenses associated with our initial public offering and related formation transactions, 3) distribute approximately $8.6 million in cash to subsidiaries of DEFS as reimbursement for capital expenditures incurred by subsidiaries of DEFS prior to our initial public offering related to assets contributed to us upon the closing of our initial public offering, which distribution was made in partial consideration of the assets contributed to us upon the closing of our initial public offering, and 4) use the remaining amount of approximately $93.7 million to fund payables and future capital expenditures (including potential acquisitions), working capital and other general partnership purposes.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure requirements and quarterly cash distributions. Our hedging program may require us to post collateral depending on commodity price movements. DEFS has issued parental guarantees for transactions that have been executed under our hedging program, which may reduce our requirement to post collateral.

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. As of January 1, 2006, we have hedged approximately 80% of our share of anticipated natural gas and NGL price risk associated with our percentage-of-proceeds arrangements through 2010 with natural gas and crude oil swaps. Additionally, as part of our gathering operations, we recover and sell condensate. As of January 1, 2006, we have hedged approximately 80% of our share of anticipated condensate price risk associated with our gathering operations through 2010 with crude oil swaps. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

Working Capital Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decline in periods of falling commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We had working capital of $31.1 million as of December 31, 2005, compared to working capital of $18.5 million as of December 31, 2004. During these periods, the increasing working capital trend was primarily attributable to higher commodity prices and the timing of fluctuations in accounts receivable and accounts payable as described above. We expect that our future working capital requirements will be impacted by these same factors.

Cash flow Net cash provided by operating activities, net cash used in investing activities and net cash provided by (used in) financing activities for the years ended December 31, 2005, 2004 and 2003 were as follows:

	Year Ended December 31,		
	2005	2004	2003
	($ in millions)		
Net cash provided by operating activities	$ 75.5	$ 25.6	$ 30.8
Net cash used in investing activities	$ (107.0)	$ (2.5)	$ (1.2)
Net cash provided by (used in) financing activities	$ 73.7	$ (23.1)	$ (29.6)

Cash Flows 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.

Cash Flows Used in Investing Activities Net cash used in investing activities in 2005 primarily 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 used in investing activities from 2003 through 2005 was generally 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.

Cash Flows Provided By/Used in Financing Activities Net cash provided by/used in financing activities from 2003 through 2005 represents the pass through of our net cash flows to DEFS under its cash management program as discussed above. Net cash provided by financing activities in 2005 was also a result of proceeds from the issuance of common units, offset by related distributions to DEFS and borrowings under the term loan and credit facilities. We expect to incur future financing cash outflows as a result of distributions to our unitholders and general partners. See Item 5. Distributions of Available Cash.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. In our Natural Gas Services segment, a significant portion of the cost of constructing new gathering lines to connect to our gathering system is generally paid for by the natural gas producer. In this segment, our expansion capital expenditures may include the construction of new pipelines that would facilitate greater movement of natural gas from western Louisiana and eastern Texas to the market hub that the PELICO system is connected to near Perryville, Louisiana. This hub provides access to several intrastate and interstate pipelines, including pipelines that transport natural gas to the northeastern United States.

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 the operating capacity or revenues of us or our equity interests.

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 and acquire assets. We actively consider a variety of assets for potential acquisitions and expansion projects.

We have budgeted maintenance capital expenditures of $2.2 million and expansion capital expenditures of $13.0 million for the year ending December 31, 2006. During 2005, our capital expenditures totaled $7.9 million, including maintenance capital expenditures of $3.3 million and expansion capital expenditures of $4.6 million. Maintenance capital expenditures in 2006 are expected to be lower than 2005 as a result of the completion of a 2005 project to add and modify compression and flow lines to increase volumes at the Ada processing plant. Expansion capital expenditures in 2006 are expected to increase as a result of the new expansion NGL project, for which expansion capital expenditures are expected to be approximately $12 million. We expect to fund future capital expenditures with restricted investments, funds generated from our operations, borrowings under our credit facility, the issuance of additional partnership units as appropriate given market conditions and the liquidation of high-grade securities that have been pledged under our credit facility.

Description of Credit Agreement. On December 7, 2005, we entered into a 5-year credit agreement that consists of:

- a $250.0 million revolving credit facility; and
- a $100.1 million term loan facility.

The revolving credit facility is available for general partnership purposes, including working capital, letters of credit, capital expenditures, acquisitions and cash distributions. We had outstanding debt of $110.0 million under our revolving credit facility as of December 31, 2005. The undrawn portion of the revolving credit facility is available for letters of credit.

We had outstanding indebtedness of $100.1 million under the term loan facility as of December 31, 2005. Amounts repaid under the term loan facility may not be reborrowed. The full balance on the term loan was collateralized by investments in high-grade securities as of December 31, 2005 for future use in funding capital expenditures (including potential acquisitions) and in order to reduce our cost of borrowings under the term loan facility.

We have the option of increasing the size of the revolving credit facility to $550 million with the consent of the issuing lenders.

Our obligations under the revolving credit facility are unsecured and the term loan facility is secured at all times by high-grade securities in an amount equal to or greater than the outstanding principal amount of the term loan. We may sell any portion of the collateral for the term loan facility at any time as long as we use the proceeds from the sale to repay term loan borrowings. 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. Indebtedness under the credit agreement ranks equally with all of our outstanding unsecured and unsubordinated debt (except that the term loan facility has a priority claim to the high-grade securities pledged to secure it).

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 our option, 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 0.27% to 1.025% dependent upon the leverage level and/or credit rating. As of December 31, 2005, approximately $0.1 million of the term loan facility bears interest at the higher of Wachovia Bank s prime rate or the federal funds rate plus a 0.50%, and the remaining $100.0 million of the term loan facility bears interest at LIBOR plus a rate per annum of 0.15%. The revolving credit facility incurs an annual facility fee of 0.08% to 0.35%

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depending on the applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

The credit agreement prohibits us from making distributions of available cash to unitholders if any default or event of default (as defined in the credit agreement) exists. Commencing with the quarter ending March 31, 2006, the credit agreement will require us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the credit agreement) of not more than 4.75 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 of not more than 5.25 to 1.0. Commencing with the quarter ending March 31, 2006, the credit agreement also will require us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the credit agreement) of equal or greater than 3.0 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2005, is as follows:

	Payments Due by Period				
	Total	2006	2007-2008	2009-2010	2011 and Thereafter
	($ in millions)				
Long-term debt(a)	$ 210.1	$	$	$ 210.1	$
Operating lease obligations	0.1	0.1			
Purchase obligations(b)	2.7	2.7			
Other long-term liabilities(c)	0.4				0.4
Total	$ 213.3	$ 2.8	$	$ 210.1	$ 0.4

(a) Interest payments on long-term debt are not included as they are based on floating interest rates and we cannot determine with accuracy the repayment date or the amount of the interest payment.

(b) Purchase obligations total $2.7 million of various non-cancelable commitments for capital projects expected to be completed in 2006. Purchase obligations exclude $87.0 million of accounts payable, $0.8 million of accrued interest payable and $3.2 million of other current liabilities recognized on the December 31, 2005 consolidated balance sheet. Purchase obligations also exclude $2.4 million of current and $2.5 million of long-term unrealized losses on non-trading derivative and hedging transactions included on the December 31, 2005 consolidated balance sheet. These amounts 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. 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 $0.3 million of asset retirement obligations and $0.1 million of environmental reserves recognized on the December 31, 2005 consolidated balance sheet.

Recent Accounting Pronouncements

New Accounting Standards *SFAS 154, Accounting Changes and Error Corrections* In June 2005, the FASB issued SFAS 154, a replacement of APB Opinion No. 20, *Accounting Changes* and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements.* Among other changes, SFAS 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to do so. SFAS 154 also provides that (1) a change in method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) correction of errors in previously issued financial statements should be termed a restatement. The new standard is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. Early adoption of this standard is permitted for accounting changes and correction of errors made in fiscal years beginning after June 1, 2005. The impact of SFAS 154 will depend on the nature and extent of any changes in accounting principles after the effective date, but we do not currently expect SFAS 154 to have a material impact on our consolidated results of operations, cash flows or financial position.

Financial Accounting Standards Board Interpretation No. 47, or FIN 47, Accounting for Conditional Asset Retirement Obligations In March 2005, the FASB issued FIN 47, which clarifies the accounting for conditional asset retirement obligations as used in SFAS 143, *Accounting for Asset Retirement Obligations.* A conditional asset retirement obligation is an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Therefore, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation under SFAS 143 if the fair value of the liability can be reasonably estimated. FIN 47 permits, but does not require, restatement of interim financial information. The provisions of FIN 47 are effective for reporting periods ending after December 15, 2005. The adoption of FIN 47 did not have a material impact on our consolidated results of operations, cash flows or financial position.

SFAS 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29 In December of 2004, the FASB issued SFAS 153, which amends APB Opinion No. 29, or APB 29, by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB 29 based on the book value of the asset surrendered with no gain or loss recognition. SFAS 153 also eliminates APB 29 s concept of culmination of an earnings process. The amendment requires that an exchange of nonmonetary assets be accounted for at fair value if the exchange has commercial substance and fair value is determinable within reasonable limits. Commercial substance is assessed by comparing the entity s expected cash flows immediately before and after the exchange. If the difference is significant, the transaction is considered to have commercial substance and should be recognized at fair value. SFAS 153 is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The adoption of SFAS 153 did not have a material impact on our consolidated results of operations, cash flows or financial position.

SFAS 123 (Revised 2004), or SFAS 123R, Share-Based Payment In December of 2004, the FASB issued SFAS 123R, which replaces SFAS 123 and supersedes APB Opinion No. 25, or APB 25. SFAS 123R requires all share-based payments to employees, including grants of employee stock options, for public entities, to be recognized in the financial statements based on their fair values beginning with the first interim or annual period after June 15, 2005. The pro forma disclosures previously permitted under SFAS 123 no longer will be an alternative to financial statement recognition. We do not currently expect SFAS 123R to have a material impact on our consolidated results of operations, cash flows, or financial position.

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

Risk and Accounting Policies

Management has established comprehensive risk management policies and a risk management committee to monitor and manage market risks associated with commodity prices, counterparty credit and interest rates. 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 committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The Risk Management Policy was adopted and the committee was formed effective with our board of directors approval effective February 8, 2006. Prior to the formation of the committee, we were utilizing DEFS risk management policies and procedures and risk management committee.

See Critical Accounting Policies and Estimates Revenue Recognition for further discussion of the accounting for derivative contracts.

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Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketing services and industrial end-users. Substantially all of our natural gas and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We operate under DEFS credit policy. DEFS credit policy promotes the use of master collateral agreements to mitigate credit exposure. Collateral agreements provide for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with DEFS credit policy. The collateral agreements also provide that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our standard gas and NGL sales contracts contain adequate assurance provisions which allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment in a form satisfactory to us.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

Interest Rate Risk

The credit markets recently have experienced 50-year record lows in interest rates. As the overall economy strengthens, it is likely that monetary policy will continue to tighten further, resulting in higher interest rates to counter possible inflation. 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. Based on the borrowings under our revolving credit facility as of December 31, 2005 of $110 million, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.6 million annualized increase or decrease in interest expense. In February 2006, the board of directors approved management to hedge up to 85% of outstanding floating rate debt. As of March 1, 2006, no interest rate swaps have been executed.

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. 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. All derivative activity reflected in the combined financial statements for periods prior to December 7, 2005 was transacted by us and DEFS prior to our initial public offering and was transferred and/or allocated to us, as more fully discussed in the notes to our consolidated financial statements. All derivative activity reflected in the consolidated financial statements from December 7, 2005 and going forward has been and will be transacted by us.

For the year ending December 31, 2006, we expect that a $1.00 per MMBtu change in price of natural gas, a $0.10 per gallon change in NGL prices and a $5.00 per barrel change in condensate prices would change our gross margin by approximately $0.2 million, $0.3 million and $0.3 million, respectively. These sensitivities include the effect of our hedging strategies executed in September 2005. Please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies for more information about these hedging strategies. The magnitude of the impact on gross margin of changes in natural gas, NGL and condensate prices presented may not be representative of the magnitude of the impact on gross margin for different commodity prices or contract portfolios. Prices for these products can also affect our profitability indirectly by influencing the level of drilling activity and related opportunities for our services.

Valuation Valuation of a contract s fair value is validated by an internal group independent of the trading areas of DEFS. 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 verify 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.

Hedging Strategies We closely monitor the risks associated with these 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.

In September 2005, we executed a series of derivative financial instruments which have been designated as cash flow hedges of the price risk associated with our forecasted sales of natural gas, NGLs and condensate. Because of the strong correlation between NGL prices and crude oil prices and the lack of liquidity in the NGL financial market, we have used crude oil swaps to hedge NGL price risk. As a result of these transactions, effective January 1, 2006 we have hedged approximately 80% of our expected natural gas and NGL commodity price risk relating to our percentage of proceeds gathering and processing contracts and condensate commodity price risk relating to condensate recovered from our gathering operations through 2010.

The natural gas and NGL price risk is associated with our percentage-of-proceeds arrangements. The condensate price risk is associated with our gathering operations where we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices. We continually monitor our hedging program and expect to continue to adjust our hedge position as conditions warrant.

The derivative financial instruments we have entered into are typically referred to as swap contracts. These swap contracts entitle us to receive payment 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 to the counterparty to the extent that the reference price is higher than the swap price stated in the contract. The swap contracts we have entered into to hedge our exposure to price risk associated with natural gas relate to the price of natural gas, settle on a monthly basis and provide that the reference price for each settlement period are the monthly index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area as published by an independent industry publication. The swap price for each of these natural gas hedge contracts is $9.20 per MMBtu, and the notional volume for each period covered, and time periods covered, by these contracts is set forth in the table below. The swap contracts we have entered into to hedge our exposure to price risk associated with NGLs and condensate relate to the price of crude oil, settle on a monthly basis and provide that the reference price for each settlement period are the average price for the month in which the NYMEX futures contracts for light, sweet crude delivered at Cushing, Oklahoma. The weighted average swap price for these crude oil hedge contracts is $63.27 per barrel, and the notional volume for each period covered, and the time periods covered, by these contracts is set forth in the table below.

The counterparties to each of the swap contracts we have entered into 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. Based on the five-year forward price curve for NYMEX crude oil contracts, our exposure to a counterparty could exceed a predetermined collateral threshold if the forward curve price exceeds $83.50 per barrel of light, sweet crude oil and with the other counterparty if this forward curve price exceeds $96.31 per barrel of light, sweet crude oil. As the swap contracts settle and the notional volume outstanding decreases, the forward curve price at which point collateral is required would be higher. Predetermined collateral thresholds are generally dependent

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on DEFS credit rating and would be reduced to $0 in the event DEFS credit rating were to fall below investment grade. DEFS has provided guarantees to support the hedging contracts.

The following table sets forth additional information about our natural gas and crude oil swaps:

Period	Commodity	Notional Volume	Reference Price	Swap Price
January 2006 December 2006	Natural Gas	4,200 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2007 December 2007	Natural Gas	4,100 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2008 December 2008	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2009 December 2009	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2010 December 2010	Natural Gas	3,900 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2006 December 2006	Crude Oil	670 Bbls/d	NYMEX Index Price(2)	$63.27/Bbl
January 2007 December 2007	Crude Oil	660 Bbls/d	NYMEX Index Price(2)	$63.27/Bbl
January 2008 December 2008	Crude Oil	650 Bbls/d	NYMEX Index Price(2)	$63.27/Bbl
January 2009 December 2009	Crude Oil	650 Bbls/d	NYMEX Index Price(2)	$63.27/Bbl
January 2010 December 2010	Crude Oil	640 Bbls/d	NYMEX Index Price(2)	$63.27/Bbl

(1) NYMEX index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.

(2) NYMEX index price for light, sweet crude oil delivered at Cushing, Oklahoma.

At December 31, 2005, the fair value of the crude oil and natural gas swaps described above was a $1.4 million gain and a $0.7 million loss, respectively.

In addition, on an infrequent basis, we may allow customers to manage their commodity price risk by offering natural gas at a fixed price. When we enter into commercial arrangements with a fixed price, we also transact an offsetting financial hedge with another party. At December 31, 2005, there was one financial hedge of this nature that had a fair value loss of $0.1 million.

To the extent that a hedge is effective, there is no impact to the consolidated statements of operations until delivery or settlement occurs. Several factors influence the effectiveness of a hedge contract, including the use of contracts with different commodities or unmatched terms. Hedge effectiveness is monitored regularly and measured quarterly.

The fair value of our qualifying hedge positions at a point in time is not necessarily indicative of the results realized when such contracts mature.

For contracts that are designated and qualify as effective hedge positions of future cash flows, or fair values of assets, liabilities or firm commitments, to the extent that the hedge relationships are effective, their market value change impacts are not recognized in current earnings. The unrealized gains or losses on these contracts are deferred in AOCI for cash flow hedges or included in other current or noncurrent assets or liabilities on the consolidated balance sheets for fair value hedges of firm commitments. Amounts in AOCI are realized in earnings concurrently with the transaction being hedged. However, in instances where the hedging contract no longer qualifies for hedge accounting, amounts included in AOCI through the date of de-designation remain in AOCI until the underlying transaction actually occurs. The derivative contract (if continued as an open position) will be marked to market currently through earnings.

The fair value of our qualifying hedge positions 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 Hedge Contracts as of December 31, 2005				
Sources of Fair Value	**Maturity in 2006**	**Maturity in 2007**	**Maturity in 2008**	**Maturity in 2009 and Thereafter**	**Total Fair Value**
			($ in millions)		
Prices supported by quoted market prices and other external sources	$ (1.8)	$ (0.2)	$ 0.1	$	$ (1.9)
Prices based on models or other valuation techniques	(0.5)	(1.4)		4.4	2.5
Total	$ (2.3)	$ (1.6)	$ 0.1	$ 4.4	$ 0.6

The prices supported by quoted market prices and other external sources category includes our New York Mercantile Exchange swap positions in crude oil which have currently quoted monthly crude oil prices for the next 29 months. In addition, this category includes our forward positions in natural gas basis swaps at points for which over-the-counter, or OTC, broker quotes are available. On average, OTC quotes for natural gas swaps extend 10 months into the future. 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.

Normal Purchases and Normal Sales If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract s fair value in the consolidated financial statements is required until the associated delivery period occurs. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas or NGLs in future periods.

Natural Gas Asset-Based Marketing We manage our natural gas activities with both physical and financial transactions. To the extent possible, we match our natural gas supply portfolio to our sales portfolio. The majority of this financial activity is in the current or nearby month and is accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Our profitability is affected by changes in prevailing natural gas, NGL and condensate prices. Historically, changes in the prices of most NGL products and condensate have generally correlated with changes in the price of crude oil. Natural gas, NGL and condensate prices are volatile and are impacted by changes in the supply and demand for natural gas, NGLs and condensate as well as market uncertainty. For a discussion of the volatility of natural gas and NGL prices, please read Risk Factors Risks Related to Our Business The cash flow from our Natural Gas Services segment is affected by natural gas, NGL and condensate prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units.

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of DCP Midstream Partners, LP (the Company) as of December 31, 2005 and 2004, and the related consolidated statements of operations, comprehensive income, changes in partners equity, and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in Item 15. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2005 and 2004 and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

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

/s/ Deloitte & Touche LLP

Denver, Colorado
March 1, 2006

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	($ in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 42.2	$
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.1 million and $0.2 million, respectively	24.4	59.0
Affiliates	56.5	1.9
Imbalances	1.1	0.1
Inventories	0.1	
Unrealized gains on non-trading derivative and hedging transactions	0.1	
Other	0.1	0.1
Total current assets	124.5	61.1
Restricted investments	100.4	
Property, plant and equipment, net	168.9	172.0
Intangible asset, net	2.1	2.2
Equity method investment	5.3	5.8
Unrealized gains on non-trading derivative and hedging transactions	5.4	
Other non-current assets	0.7	
Total assets	$ 407.3	$ 241.1
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 42.5	$ 35.2
Affiliates	42.0	3.2
Imbalances	2.5	1.4
Unrealized losses on non-trading derivative and hedging transactions	2.4	0.1
Accrued interest payable	0.8	
Other	3.2	2.7
Total current liabilities	93.4	42.6
Long-term debt	210.1	
Unrealized losses on non-trading derivative and hedging transactions	2.5	
Other long-term liabilities	0.4	0.1
Total liabilities	306.4	42.7

Commitments and contingent liabilities		
Partners equity:		
DCP Midstream Partners Predecessor equity		198.4
Common unitholders (10,357,143 units issued and outstanding at December 31, 2005)	215.8	
Subordinated unitholders (7,142,857 convertible units issued and outstanding at December 31, 2005)	(109.7)	
General partner interest (2% interest with 357,143 equivalent units outstanding at December 31, 2005)	(5.6)	
Accumulated other comprehensive income	0.4	
Total partners equity	100.9	198.4
Total liabilities and partners equity	$ 407.3	$ 241.1

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2005	2004	2003
	($ in millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, NGLs and condensate	$ 647.8	$ 412.7	$ 319.3
Sales of natural gas, NGLs and condensate to affiliates	114.5	77.0	134.7
Transportation and processing services	12.3	9.5	9.5
Transportation and processing services to affiliates	10.6	10.4	9.1
(Losses) gains from non-trading derivative activity affiliate	(0.7)	(0.1)	2.5
Total operating revenues	784.5	509.5	475.1
Operating costs and expenses:			
Purchases of natural gas and NGLs	601.4	404.1	309.3
Purchases of natural gas and NGLs from affiliates	107.9	48.5	121.3
Operating and maintenance expense	14.2	13.6	15.0
Depreciation and amortization expense	11.7	12.6	12.8
General and administrative expense	4.0		
General and administrative expense affiliates	7.4	6.5	7.1
Total operating costs and expenses	746.6	485.3	465.5
Operating income	37.9	24.2	9.6
Interest income	0.5		
Interest expense	(0.8)		
Earnings from equity method investment	0.4	0.6	0.4
Impairment of equity method investment		(4.4)	
Net income	$ 38.0	$ 20.4	$ 10.0
Less:			
Net income attributable to DCP Midstream Partners Predecessor	(33.3)	(20.4)	(10.0)
General partner interest in net income	(0.1)		
Net income allocable to limited partners	$ 4.6	$	$
Net income per limited partners unit basic and diluted	$ 0.20	$	$
Weighted average limited partners units outstanding basic and diluted	17.5		

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2005	**2004**	**2003**
	($ in millions)		
Net income	$ 38.0	$ 20.4	$ 10.0
Other comprehensive income:			
Net unrealized gains on cash flow hedges	0.4		
Total other comprehensive income	0.4		
Total comprehensive income	$ 38.4	$ 20.4	$ 10.0

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS EQUITY

	DCP Midstream Partners Predecessor Equity	Common Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income	Total Partners Equity
			($ in millions)			
Balance, January 1, 2003	$ 220.7	$	$	$	$	$ 220.7
Net change in parent advances	(29.6)					(29.6)
Net income	10.0					10.0
Balance, December 31, 2003	201.1					201.1
Net change in parent advances	(23.1)					(23.1)
Net income	20.4					20.4
Balance, December 31, 2004	198.4					198.4
Net change in parent advances	(123.6)					(123.6)
Other comprehensive income					0.4	0.4
Net income through December 6, 2005	33.3					33.3
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 Duke Energy Field Services	(218.7)					(218.7)
Allocation of DCP Midstream Partners 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 from December 7, 2005 through December 31, 2005		2.7	1.9	0.1		4.7
Balance, December 31, 2005	$	$ 215.8	$ (109.7)	$ (5.6)	$ 0.4	$ 100.9

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2005	2004	2003
	($ in millions)		
OPERATING ACTIVITIES:			
Net income	$ 38.0	$ 20.4	$ 10.0
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense and impairment charge	11.7	17.0	12.8
Other, net	(0.3)	(0.6)	0.2
Change in operating assets and liabilities which provided (used) cash:			
Accounts receivable	(20.8)	(15.7)	(2.1)
Net unrealized (gains) losses on non-trading derivative and hedging transactions	(0.3)	0.6	(0.5)
Inventories	(0.1)		
Accounts payable	47.2	3.8	9.2
Accrued interest	0.8		
Other current assets and liabilities	(0.6)	0.1	1.2
Other noncurrent assets and liabilities	(0.1)		
Net cash provided by operating activities	75.5	25.6	30.8
INVESTING ACTIVITIES:			
Capital expenditures	(7.9)	(3.1)	(2.7)
Proceeds from sales of assets	1.2	0.6	1.5
Purchases of available-for-sale securities	(731.0)		
Proceeds from sales of available-for-sale securities	630.8		
Other investing activities	(0.1)		
Net cash used in investing activities	(107.0)	(2.5)	(1.2)
FINANCING ACTIVITIES:			
Proceeds from issuance of common units, net of offering costs	206.4		
Borrowings under credit facility	110.0		
Borrowings under term loan facility	100.1		
Distributions to Duke Energy Field Services	(218.7)		
Net change in advances from Duke Energy Field Services	(123.6)	(23.1)	(29.6)
Deferred financing costs	(0.5)		
Net cash provided by (used in) financing activities	73.7	(23.1)	(29.6)
Net change in cash and cash equivalents	42.2		
Cash and cash equivalents, beginning of period			

Cash and cash equivalents, end of period	$	42.2	$		$

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years Ended December 31, 2005, 2004 and 2003

1. Description of Business and Basis of Presentation

DCP Midstream Partners, LP (with its consolidated subsidiaries, the Partnership) is engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas and the business of transporting and selling natural gas liquids, or NGLs.

The Partnership includes the results of operations, financial position, cash flows and changes in partners equity in its North Louisiana system assets (Minden , Ada , and PELICO), its NGL transportation pipeline (Seabreeze) and its 45 equity method investment in Black Lake Pipe Line Company (Black Lake) that were contributed to the Partnership on December 7, 2005 by Duke Energy Field Services LLC (DEFS or the Parent). DEFS is owned 50% by Duke Energy Corporation (Duke Energy) and 50% by ConocoPhillips. The consolidated financial statements include a 50% equity interest in Black Lake in 2003, 2004 and the period beginning January 1, 2005 through December 6, 2005. Upon closing of the Partnership s initial public offering on December 7, 2005, DEFS retained a 5% interest of Black Lake. The Partnership owns a 45% equity interest in Black Lake.

The Partnership closed its initial public offering of 10,350,000 common units at a price of $21.50 per unit on December 7, 2005. Proceeds from the initial public offering were $206.4 million, net of offering costs. In addition, concurrent with the initial public offering, DEFS contributed to the Partnership the assets described above and retained (i) a 2% general partner interest in the Partnership; (ii) 7,142,857 subordinated units; and (iii) 7,143 common units, representing in aggregate an approximate 42% interest in the Partnership. The Partnership s general partner is DCP Midstream GP, LP, a wholly-owned subsidiary of DEFS. See Note 4 for information related to the distribution rights of the common and subordinated unitholders and the incentive distribution rights held by the general partner.

DEFS directs the business operations of the Partnership through its ownership and control of the Partnership s general partner. DEFS and its affiliates employees provide administrative support to the Partnership and operate its assets.

The consolidated financial statements include the accounts of the Partnership, and prior to December 7, 2005 the assets, liabilities and operations contributed to us by DEFS and its wholly-owned subsidiaries (DCP Midstream Partners Predecessor) upon the closing of the Partnership s initial public offering, and have been prepared in accordance with accounting principles generally accepted in the United States of America. The consolidated financial statements of DCP Midstream Partners Predecessor have been prepared from the separate records maintained by DEFS and may not necessarily be indicative of the conditions that would have existed or the results of operations if DCP Midstream Partners Predecessor had been operated as an unaffiliated entity. All significant intercompany balances and transactions have been eliminated. Transactions between the Partnership and other DEFS operations have been identified in the consolidated financial statements as transactions between affiliates (see Note 7).

2. Summary of Significant Accounting Policies

Use of Estimates Conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the financial statements and notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results could be different from those estimates.

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

Restricted Investments Restricted investments consist of $100.4 million in investments in commercial paper and various other high-grade debt securities. These investments are used as collateral to secure the term

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

loan portion of the credit facility and are to be used only for future capital expenditures. These investments are classified as available-for-sale securities under Statement of Financial Accounting Standards (SFAS) 115 as management does not intend to hold them to maturity nor are they bought or sold with the objective of generating profits on short-term differences in prices. These investments are recorded at fair value with changes in fair market value recorded as unrealized holding gains or losses in accumulated other comprehensive income (AOCI). At December 31, 2005, no amounts related to these investments were deferred in AOCI. Due to the short-term, highly liquid nature of the securities held by the Partnership and as interest rates are re-set on a daily, weekly or monthly basis, the cost, including accrued interest on investments, approximates fair value. During 2004, the Partnership did not invest in these instruments.

Accounting for Risk Management and Hedging Activities and Financial Instruments Each derivative not qualifying for the normal purchases and normal sales exception under SFAS No. 133 (SFAS 133), *Accounting for Derivative Instruments and Hedging Activities* as amended, is recorded on a gross basis in the consolidated balance sheets at its fair value as Unrealized gains or Unrealized losses on non-trading derivative and hedging transactions. Derivative assets and liabilities remain classified in the Partnership s consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging transactions at fair value until the contractual settlement period occurs.

All derivative activity reflected in the combined financial statements for periods prior to December 7, 2005 was transacted by the Partnership and DEFS and its subsidiaries prior to the initial public offering and was transferred and/or allocated to the Partnership. All derivative activity reflected in the consolidated financial statements from December 7, 2005 and going forward has been and will be transacted by the Partnership. Management designates each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activity, are designated as non-trading derivative activity. For the periods presented, the Partnership did not have any trading activity, however, the Partnership did have cash flow and fair value hedge activity, normal purchases and normal sales activity, and non-trading derivative activity included in these consolidated financial statements. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

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

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

(b) Hedge method An accounting method whereby the effective portion of the change in the fair value of the asset or liability is recorded as a balance sheet adjustment and there is no recognition in the results of operations for the effective portion until the service is provided or the associated delivery period occurs.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) Accrual method An accounting method whereby there is no recognition in the results of operations for changes in fair value of a contract until the service is provided or the associated delivery period occurs.

Cash Flow and Fair Value Hedges For derivatives designated as a cash flow hedge or a fair value hedge, management prepares formal documentation of the hedge in accordance with SFAS 133. In addition, management formally assesses, both at the inception of the hedge and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on non-trading derivative and hedging transactions. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in partners equity as accumulated other comprehensive income and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction occurs, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction occurs, unless it is no longer probable that the hedged transaction will occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

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

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

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

Property, Plant and Equipment Property, plant and equipment are recorded at historical cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets (see Note 8). The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

The Partnership has adopted SFAS No. 143 (SFAS 143), *Accounting for Asset Retirement Obligations,* and Financial Accounting Standards Board Interpretation No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations,* which address financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard and interpretation apply to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. FIN 47 requires the recognition of a liability of a conditional asset retirement obligation as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity.

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

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

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

Intangible Asset Intangible asset consists of a commodity contract. The commodity contract is amortized on a straight-line basis over the period of expected future benefit of approximately 25 years (see Note 9).

Equity Method Investment The Partnership accounts for investments in 20% to 50% owned affiliates, and investments in less than 20% owned affiliates where the Partnership has the ability to exercise significant influence, under the equity method.

Impairment of Equity Method Investment The Partnership evaluates its equity method investment for impairment when events or changes in circumstances indicate, in management s judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. Management assesses the fair value of its equity method investment using commonly accepted techniques, and may use more than one method,

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment.

Revenue Recognition The Partnership s primary types of sales and service activities reported as operating revenue include:

- sales of natural gas, NGLs and condensate;
- natural gas gathering, processing and transportation, from which the Partnership generates revenues primarily through the compression, gathering, treating, processing and transportation of natural gas; and
- NGL transportation from which the Partnership generates revenues from transportation fees.

Revenues associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenues associated with transportation and processing fees are recognized when the service is provided.

For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership purchases wellhead natural gas and sells processed natural gas and NGLs to third parties.

The Partnership recognizes revenues for non-trading derivative activity net in the consolidated statements of operations as (losses) gains from non-trading derivative activity, in accordance with EITF Issue No. 02-03, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.* These activities include mark-to-market gains and losses on energy derivative contracts and the financial or physical settlement of energy derivative contracts.

The Partnership generally reports revenues gross in the consolidated statements of operations, in accordance with EITF Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent.* Except for fee-based agreements, the Partnership acts as the principal in these transactions, takes title to the product, and incurs the risks and rewards of ownership.

Significant Customer The Partnership had one customer, a third party, that accounted for 24%, 31% and 26% of total operating revenues for the years ended December 31, 2005, 2004 and 2003, respectively. Revenues from this customer are reported in the NGL Logistics Segment. The Partnership also had significant transactions with affiliates (see Note 7).

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

Environmental Expenditures Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not generate current or future revenue are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

Gas and NGL Imbalance Accounting Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

other receivables or other payables using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs or with cash.

Equity-Based Compensation Under the Partnership s Long Term Incentive Plan, equity instruments may be granted to the Partnership s key employees. The Partnership accounts for equity-based compensation using the intrinsic value recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees,* and FASB Interpretation No. 44, *Accounting for Certain Transactions Involving Stock Compensation (an Interpretation of APB Opinion No. 25).* The Partnership had not granted any share-based instruments as of December 31, 2005.

DCP Midstream GP, LLC adopted a Long-Term Incentive Plan, or the Plan, for employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for the Partnership. The Plan provides for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of distribution equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 common units may be delivered pursuant to awards under the Plan. Units that are cancelled, forfeited or are withheld to satisfy DCP Midstream GP, LLC s tax withholding obligations are available for delivery pursuant to other awards. The Plan is administered by the compensation committee of DCP Midstream GP, LLC s board of directors.

Net Income per Limited Partner Unit Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income, less pro forma general partner incentive distributions under EITF Issue No. 03-6, by the weighted average number of outstanding limited partner units during the period (see Note 5).

3. New Accounting Standards

SFAS No. 154 (SFAS 154), Accounting Changes and Error Corrections. In June 2005, the FASB issued SFAS 154, a replacement of APB Opinion No. 20, *Accounting Changes* and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements* . Among other changes, SFAS 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to do so. SFAS 154 also provides that (1) a change in method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) correction of errors in previously issued financial statements should be termed a restatement. The new standard is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. Early adoption of this standard is permitted for accounting changes and correction of errors made in fiscal years beginning after June 1, 2005. The impact of SFAS 154 will depend on the nature and extent of any changes in accounting principles after the effective date, but the Partnership does not currently expect SFAS 154 to have a material impact on its consolidated results of operations, cash flows or financial position.

FIN No. 47 (FIN 47), Accounting for Conditional Asset Retirement Obligations . In March 2005, the FASB issued FIN 47, which clarifies the accounting for conditional asset retirement obligations as used in SFAS No. 143 (SFAS 143). *Accounting for Asset Retirement Obligations* . A conditional asset retirement obligation is an unconditional legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. Therefore, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation under SFAS 143 if the fair value of the liability can be reasonably estimated. FIN 47 permits, but does not require, restatement of interim financial information. The provisions of FIN 47 are effective for reporting periods ending after December 15, 2005. The adoption of FIN 47 did not have a material impact on the Partnership s consolidated results of operations, cash flows or financial position.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

SFAS No. 153 (SFAS 153), Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29. In December of 2004, the FASB issued SFAS 153, which amends APB Opinion No. 29 (APB 29) by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB 29 based on the book value of the asset surrendered with no gain or loss recognition. SFAS 153 also eliminates APB 29 s concept of culmination of an earnings process. The amendment requires that an exchange of nonmonetary assets be accounted for at fair value if the exchange has commercial substance and fair value is determinable within reasonable limits. Commercial substance is assessed by comparing the entity s expected cash flows immediately before and after the exchange. If the difference is significant, the transaction is considered to have commercial substance and should be recognized at fair value. SFAS 153 is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The adoption of SFAS 153 did not have a material impact on the Partnership s consolidated results of operations, cash flows or financial position.

SFAS No. 123 (Revised 2004) (SFAS 123R), Share-Based Payment . In December of 2004, the FASB issued SFAS 123R, which replaces SFAS 123 and supersedes APB Opinion No. 25 (APB 25). SFAS 123R requires all share-based payments to employees, including grants of employee stock options, for public entities, to be recognized in the financial statements based on their fair values beginning with the first interim or annual period after June 15, 2005. The pro forma disclosures previously permitted under SFAS 123 no longer will be an alternative to financial statement recognition. The Partnership does not currently expect SFAS 123R to have a material impact on its consolidated results of operations, cash flows or financial position.

4. Partnership Equity and Distributions

General. The partnership agreement requires that, within 45 days after the end of each quarter, the Partnership distribute all of its available cash to unitholders of record on the applicable record date, as determined by the general partner.

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

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

provide for the proper conduct of the Partnership s business;

comply with applicable law, any of the Partnership s debt instruments or other agreements; or

provide funds for distributions to the unitholders and to the general partner for any one or more of the next four quarters;

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

General Partner Interest and Incentive Distribution Rights. The general partner is entitled to 2% of all quarterly distributions that the Partnership makes prior to its liquidation. This general partner interest is represented by 357,143 general partner units. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The general partner s initial 2% interest in these distributions will be reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its 2% general partner interest.

The incentive distribution rights held by the general partner entitles it to receive an increasing share of available cash when pre-defined distribution targets are achieved. Please read the *Distributions of Available Cash during the Subordination Period and Distributions of Available Cash after the Subordination Period*

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

sections below for more details about the distribution targets and their impact on the general partner s incentive distribution rights.

Subordinated Units. All of the subordinated units are held by DEFS. The partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of available cash each quarter in an amount equal to $0.35 per common unit (the Minimum Quarterly Distribution), plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of available cash may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The earliest date at which the subordination period may end is December 31, 2008 and 50% of the subordinated units may convert to common units as early as December 31, 2007. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Distributions of Available Cash during the Subordination Period. The partnership agreement requires that the Partnership makes distributions of available cash for any quarter during the subordination period in the following manner:

first, 98% to the common unitholders, pro rata, and 2% to the general partner, until the Partnership distributes for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;

second, 98% to the common unitholders, pro rata, and 2% to the general partner, until the Partnership distributes for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;

third, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until the Partnership distributes for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter; and

fourth, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.4025 per unit for that quarter;

fifth, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter;

sixth, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter; and

thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

Distributions of Available Cash after the Subordination Period. The partnership agreement requires that the Partnership makes distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

first, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.4025 per unit for that quarter;

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

second, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter;

third, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter; and

thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

On January 25, 2006, the Partnership announced the declaration of a cash distribution of $0.095 per unit, payable on February 13, 2006 to unitholders of record on February 3, 2006. That distribution represents the pro rata portion of the Partnership s Minimum Quarterly Distribution of $0.35 per unit for the period December 7, 2005, the closing of the Partnership s initial public offering, through December 31, 2005.

5. Net Income per Limited Partner Unit

The Partnership s net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner.

EITF Issue No. 03-6, (EITF 03-6) *Participating Securities and the Two Class Method Under FASB Statement No. 128,* addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock.

EITF 03-6 requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

EITF 03-6 does not impact the Partnership s overall net income or other financial results; however, in periods in which aggregate net income exceeds the Partnership s aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of the Partnership s aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though the Partnership makes distributions on the basis of available cash and not earnings. In periods in which the Partnership s aggregate net income does not exceed its aggregate distributions for such period, EITF 03-6 does not have any impact on the Partnership s calculation of earnings per limited partner unit.

Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income, less pro forma general partner incentive distributions under EITF 03-6, by the weighted average number of outstanding limited partner units during the period.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table illustrates the Partnership s calculation of net income per limited partner unit for the year ended December 31, 2005:

Net income	$ 38.0
Less:	
Net income applicable to the period through December 6, 2005	(33.3)
Net income applicable to the period December 7, 2005 through December 31, 2005	4.7
Less: General partner interest in net income	(0.1)
Limited partners interest in net income (see Note 4)	4.6
Additional earnings allocation to general partner	(1.1)
Net income available to limited partners under EITF 03-6	$ 3.5
Net income per limited partner unit basic and diluted	$ 0.20

6. Impairment of Equity Method Investment

In the third quarter of 2004, the Partnership recognized an other-than-temporary impairment of its investment in Black Lake totaling $4.4 million as impairment of equity method investment, included in the consolidated statements of operations. This investment was written down to fair value which was determined based on management s best estimates of discounted future cash flow models. The charge associated with this impairment is recorded in the NGL Logistics segment.

7. Agreements and Transactions with Affiliates

DEFS

Omnibus Agreement

The employees supporting the Partnership s operations are employees of DEFS. The Partnership is required to reimburse DEFS for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs and taxes. DEFS also provides centralized corporate functions on behalf of the Partnership, 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. DEFS records the accrued liabilities and prepaid expenses for most general and administrative expenses in its financial statements, including liabilities related to payroll, short and long-term incentive plans, employee retirement and medical plans, paid time off, audit, tax, insurance and other service fees. The Partnership s share of those costs has been allocated based on the Partnership s proportionate net investment (consisting of property, plant and equipment, net, equity method investment, and intangible assets, net) compared to DEFS net investment. In management s estimation, the allocation methodologies used are reasonable and result in an allocation to the Partnership of its costs of doing business borne by DEFS.

Upon the closing of the initial public offering, the Partnership entered into an Omnibus Agreement with DEFS, its general partner and others that addresses the following matters:

- the Partnership s obligation to reimburse DEFS the payment of operating expenses, including salary and benefits of operating personnel, it incurs on the Partnership s behalf in connection with the Partnership s business and operations;

- the Partnership s obligation to reimburse DEFS for providing the Partnership with general and administrative services with respect to its business and operations, which is capped at a maximum of $4.8 million, subject to an increase for 2007 and 2008 based on increases in the Consumer Price Index

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and subject to further increases in connection with expansions of the Partnership s operations through the acquisition or construction of new assets or businesses with the concurrence of the Partnership s special committee;

the Partnership s obligation to reimburse DEFS for insurance coverage expenses it incurs with respect to the Partnership s business and operations and with respect to director and officer liability coverage;

DEFS obligation to indemnify the Partnership for certain liabilities and the Partnership s obligation to indemnify DEFS for certain liabilities;

DEFS obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for the Partnership s obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements are in effect as of the closing of the initial public offering until the earlier to occur of the fifth anniversary of the closing of the initial public offering or such time as the Partnership obtains an investment grade credit rating from either Moody s Investor Services, Inc. or Standard & Poor s Ratings Group with respect to any of its unsecured indebtedness; and

DEFS obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for the Partnership s obligations related to commercial contracts with respect to its business or operations that are in effect at the closing of the initial public offering until the expiration of such contracts.

Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions, will be terminable by DEFS at its option if the general partner is removed without cause and units held by the general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a change of control of the Partnership, the general partner or the general partner s general partner.

Reimbursement of Operating and General and Administrative Expense

Under the Omnibus Agreement the Partnership reimburses DEFS for the payment of certain operating expenses and for the provision of various general and administrative services for the Partnership s benefit with respect to the assets contributed to it at the closing of the initial public offering. The Omnibus Agreement provides that the Partnership will reimburse DEFS for its allocable portion of the premiums on insurance policies covering its assets.

Pursuant to these arrangements, DEFS performs centralized corporate functions for the Partnership, such as legal, accounting, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The Partnership will reimburse DEFS for the direct expenses to provide these services as well as other direct expenses it incurs on the Partnership s behalf, such as salaries of operational personnel performing services for the Partnership s benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits.

Competition

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Indemnification

Under the Omnibus Agreement, DEFS will indemnify the Partnership for three years after the closing of the initial public offering against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing date of the initial public offering. DEFS maximum liability for this indemnification obligation does not exceed $15 million and DEFS does not have any obligation under this indemnification until the Partnership s aggregate losses exceed $250,000. DEFS has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of the initial public offering. The Partnership has agreed to indemnify DEFS against environmental liabilities related to the Partnership s assets to the extent DEFS is not required to indemnify the Partnership.

Additionally, DEFS will indemnify the Partnership for losses attributable to title defects, retained assets and liabilities (including preclosing litigation relating to contributed assets) and income taxes attributable to pre-closing operations. The Partnership will indemnify DEFS for all losses attributable to the postclosing operations of the assets contributed to the Partnership, to the extent not subject to DEFS indemnification obligations. In addition, DEFS has agreed to indemnify the Partnership for up to $5.3 million of its pro rata share of any capital contributions required to be made by the Partnership 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 2005 through 2007. DEFS has also agreed to indemnify the Partnership for 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 scheduled pipeline integrity testing occurring in 2006 and 2007.

Other Agreements and Transactions with DEFS

Prior to the initial public offering on December 7, 2005, the Partnership participated in DEFS cash management program. As a result, the Partnership had no cash balances on the consolidated balance sheets and all cash management activity was performed by DEFS on behalf of the Partnership, including collection of receivables, payment of payables, and the settlement of sales and purchases transactions between the Partnership and DEFS, which were recorded as parent advances and included in accounts receivable affiliates or accounts payable affiliates. Subsequent to the initial public offering, the Partnership maintains separate cash accounts, which are managed by DEFS.

The Partnership has entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase natural gas and transport it to the PELICO system where the Partnership will buy the gas from DEFS at its weighted average cost plus a contractually agreed to marketing fee. In addition, for a significant portion of the gas that the Partnership sells out of its PELICO system, the Partnership has entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase that natural gas from the Partnership and transport it to a sales point at a price equal to its net weighted average sales price less a contractually agreed to marketing fee. These agreements have a two year term beginning in December 2005.

In addition, for certain industrial end-user customers of the PELICO system, from time to time the Partnership may sell aggregated natural gas to a subsidiary of DEFS which in turn would resell natural gas to these customers. The sales price to the subsidiary of DEFS is equal to that subsidiary of DEFS net weighted average sales price less a contractually agreed to marketing fee.

Effective December 1, 2005, the Partnership entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase the NGLs that were historically purchased by the Seabreeze pipeline, and DEFS will pay the Partnership to transport the NGLs pursuant to a fee-based rate that will be applied to the volumes transported. The Partnership has entered into this fee-based contractual arrangement with the objective of generating approximately the same operating income per barrel transported that it

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

realized when it was the purchaser and seller of NGLs. The Partnership does not take title to the products transported on the NGL pipeline; rather, the shipper retains title and the associated commodity price risk. DEFS is the sole shipper on the Seabreeze pipeline under a 17-year transportation agreement expiring in 2022. The Seabreeze pipeline collects only fee-based transportation revenue under this agreement.

The Partnership sells NGLs and condensate from its Minden and Ada processing plants and the PELICO system to a subsidiary of DEFS equal to that subsidiary of DEFS net weighted average sales price.

Management anticipates continuing to purchase and sell these commodities to DEFS in the ordinary course of business. DEFS was a significant customer during the years ended December 31, 2005, 2004 and 2003.

Duke Energy

The Partnership charges transportation fees, sells a portion of its residue gas to, and purchases raw natural gas from, Duke Energy and its affiliates. Management anticipates continuing to purchase and sell these commodities to Duke Energy and its affiliates in the ordinary course of business. Duke Energy was a significant customer during the year ended December 31, 2003.

ConocoPhillips

The Partnership charges transportation fees and sells a portion of its residue gas and NGLs to and purchases raw natural gas from ConocoPhillips and its affiliates. The Partnership has a fee-based contractual relationship with ConocoPhillips pursuant to which ConocoPhillips has dedicated all of its natural gas production within an area of mutual interest to the assets in the Partnership s Natural Gas Services segment. Management anticipates continuing to purchase and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, the Partnership may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by the Partnership. The Partnership received $0.2 million, $0.3 million and $0.5 million of capital reimbursements during the years ended December 31, 2005, 2004 and 2003, respectively.

The following table summarizes the transactions with DEFS, Duke Energy and ConocoPhillips as described above ($ in millions):

	For the Years Ended December 31,		
	2005	**2004**	**2003**
Duke Energy Field Services:			
Sales of natural gas, NGLs and condensate	$ 105.8	$ 63.0	$ 50.0
Transportation and processing services	$ 0.3	$	$
Purchases of natural gas and NGLs	$ 86.1	$ 26.7	$ 87.8
(Losses) gains from non-trading derivative activity	$ (0.7)	$ (0.1)	$ 2.5
General and administrative expense	$ 7.4	$ 6.5	$ 7.1
Duke Energy:			

Sales of natural gas, NGLs and condensate	$ 1.4	$ 10.3	$ 81.1
Transportation and processing services	$ 0.3	$ 0.5	$ 0.7
Purchases of natural gas and NGLs	$ 3.1	$ 3.4	$ 1.6
ConocoPhillips:			
Sales of natural gas, NGLs and condensate	$ 7.3	$ 3.7	$ 3.6
Transportation and processing services	$ 10.0	$ 9.9	$ 8.4
Purchases of natural gas and NGLs	$ 18.7	$ 18.4	$ 31.9

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Partnership had accounts receivable and accounts payable with affiliates as follows ($ in millions):

	December 31, 2005	December 31, 2004
Duke Energy Field Services:		
Accounts receivable	$ 53.5	$ 0.7
Accounts payable	$ 15.9	$
Duke Energy:		
Accounts receivable	$ 0.4	$
Accounts payable	$ 23.6	$
ConocoPhillips:		
Accounts receivable	$ 2.6	$ 1.2
Accounts payable	$ 2.5	$ 3.2

8. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows ($ in millions):

	Depreciable Life	December 31, 2005	December 31, 2004
Gathering systems	15 30 Years	$ 95.9	$ 92.9
Processing plants	25 30 Years	53.4	53.7
Transportation	25 30 Years	127.4	127.2
General plant	3 5 Years	2.7	2.7
Construction work in progress		8.5	3.1
Property, plant and equipment		287.9	279.6
Accumulated depreciation		(119.0)	(107.6)
Property, plant and equipment, net		$ 168.9	$ 172.0

Depreciation expense was $11.6 million, $12.5 million, $12.7 million for the years ended December 31, 2005, 2004 and 2003, respectively.

At December 31, 2005, the Partnership had non-cancelable purchase obligations of $2.7 million for capital projects expected to be completed in 2006. In addition, property, plant and equipment includes $1.1 million and $0.1 million of non-cash additions for the years ended December 31, 2005 and 2004, respectively. There were no non-cash additions to property, plant and equipment in 2003.

Asset Retirement Obligations The Partnership s asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements and contractual leases for land use. SFAS 143 was effective for fiscal years beginning after June 15, 2002, and was adopted by the Partnership on January 1, 2003. At January 1, 2003, the implementation of SFAS 143 resulted in a net increase in total assets of $0.1 million, consisting of an increase in net property, plant and equipment. Long-term liabilities increased by $0.1 million, which represents the establishment of an asset retirement obligation liability. A cumulative-effect of a change in accounting principle adjustment, which was not significant, was recorded on January 1, 2003 as a reduction in earnings. Accretion expense for the years ended December 31, 2005, 2004 and 2003 was not significant.

The asset retirement obligation is adjusted each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The asset retirement obligation,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

included in other long-term liabilities in the consolidated balance sheets, as of December 31, 2005 and 2004 was $0.3 million and $0.1 million, respectively.

One of the Partnership s owned gas processing plants contains asbestos. If the portion of the plant containing asbestos were to be dismantled, the Partnership would be legally required to remove the asbestos. The Partnership currently has no plans to take actions that would require the removal of the asbestos in this plant. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

9. Intangible Asset

Intangible asset consists of a commodity contract. The gross carrying amount and accumulated amortization for the commodity contract is as follows ($ in millions):

	December 31,	
	2005	2004
Intangible asset	$ 2.5	$ 2.5
Accumulated amortization	(0.4)	(0.3)
Intangible asset, net	$ 2.1	$ 2.2

For each of the years ended December 31, 2005, 2004 and 2003, the Partnership recorded amortization expense associated with the commodity contract of $0.1 million. As of December 31, 2005, the remaining amortization period for this contract was 21.3 years.

Estimated future amortization for this contract is as follows ($ in millions):

	December 31, 2005
2006	$ 0.1
2007	0.1
2008	0.1
2009	0.1
2010	0.1
Thereafter	1.6
Total	$ 2.1

10. Equity Method Investment

The Partnership has an investment in the following business accounted for using the equity method, included in the NGL Logistics segment ($ in millions):

	December 31, 2005	December 31, 2004
Black Lake Pipe Line Company	$ 5.3	$ 5.8

Prior to December 7, 2005, DCP Midstream Partners Predecessor held a 50% interest in Black Lake. Upon completion of the Partnership s initial public offering, DEFS retained a 5% interest in Black Lake. The investment above accounts for a 45% and 50% ownership interest as of December 31, 2005 and 2004, respectively.

Black Lake owns a 317 mile NGL pipeline, with a throughput capacity of approximately 40 MBbls/d. The pipeline receives NGLs from a number of gas plants in Louisiana and Texas. There was a deficit between

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the carrying amount of the investment and the underlying equity of Black Lake of $7.0 million, $8.1 million and $3.9 million at December 31, 2005, 2004 and 2003, respectively, which is associated with, and is being accreted over the life of, the underlying long-lived assets of Black Lake.

Earnings from equity method investment amounted to the following ($ in millions):

	December 31,		
	2005	**2004**	**2003**
Black Lake Pipe Line Company	$ 0.4	$ 0.6	$ 0.4

Distributions received were $0.6 million during the year ended December 31, 2003. The Partnership did not receive any distributions during the years ended December 31, 2005 and 2004.

The following summarizes financial information of Black Lake ($ in millions):

	December 31,		
	2005	**2004**	**2003**
Statements of operations:			
Operating revenues	$ 3.3	$ 3.2	$ 3.2
Operating expenses	3.9	2.4	2.9
Net (loss) income	$ (0.6)	$ 0.8	$ 0.3
Balance sheet:			
Current assets	$ 4.8	$ 4.3	
Noncurrent assets	17.4	18.0	
Current liabilities	0.7	0.2	
Net assets	$ 21.5	$ 22.1	

11. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

Commodity price risk The Partnership s principal operations of gathering, processing, and transportation of natural gas, and the accompanying operations of transportation and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, the Partnership has an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts entered into to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs and related products produced, processed, transported or stored.

Credit risk The Partnership sells natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DEFS, national wholesale marketers, industrial end-users and gas-fired power plants. In the NGL Logistics segment, the Partnership s principal customers include an affiliate of DEFS, producers and marketing companies. Substantially all of the Partnership s natural gas and NGL sales are made at market-based prices. This concentration of credit risk may affect the Partnership s overall credit risk in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, management analyzes the counterparties financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of these limits on an ongoing basis. The Partnership operates under DEFS corporate credit policy. DEFS corporate credit policy prescribes the use of master collateral agreements to mitigate credit exposure. Collateral agreements provide for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with DEFS credit

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

policy. The collateral agreements also provide that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, the Partnership s standard natural gas and NGL sales contracts contain adequate assurance provisions which allow the Partnership to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment in a form satisfactory to the Partnership.

Commodity cash flow hedges In September 2005, the Partnership executed a series of derivative financial transactions which have been designated as cash flow hedges of the price risk associated with its forecasted sales of natural gas, NGLs and condensate. As a result of those transactions, the Partnership hedged approximately 80% of its expected natural gas and NGL commodity price risk effective January 1, 2006 relating to its percentage of proceeds gathering and processing contracts and condensate commodity price risk relating to condensate recovered from gathering operations through 2010.

The Partnership may, from time to time, use cash flow hedges, as specifically defined by SFAS 133, to reduce the potential negative impact that commodity price changes could have on its earnings, and its ability to adequately plan for cash needed for debt service, distributions and capital expenditures.

The Partnership used natural gas and crude oil swaps to hedge the impact of market fluctuations in the price of NGLs, natural gas and condensate. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is accumulated in AOCI, and the ineffective portion is recorded in the consolidated statements of operations. For the year ended December 31, 2005, the amount of the ineffectiveness was a gain of approximately $0.3 million. For the year ended December 31, 2005, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring or due to a derivative no longer qualifying as an effective hedge. All components of each derivative s gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

During the period in which the hedged transaction occurs, amounts in AOCI associated with the hedged transaction will be reclassified to the consolidated statements of operations in the same accounts as the item being hedged. As of December 31, 2005, there were $0.4 million of net deferred gains related to commodity cash flow derivative contracts in AOCI. As of December 31, 2004 and 2003, no amounts related to cash flow hedges were deferred in AOCI. As of December 31, 2005, $2.4 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions occur; however, due to the volatility of the commodities markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings.

Commodity fair value hedges The Partnership uses fair value hedges to hedge exposure to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. The Partnership may hedge producer price locks (fixed price gas purchases) to reduce its exposure to fixed price risk via swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index-based).

For the years ended December 31, 2005, 2004 and 2003, the gains or losses representing the ineffective portion of the Partnership s fair value hedges were not material. All components of each derivative s gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted. At December 31, 2005 and 2004, there were no firm commitments that no longer qualified as fair value hedge items and therefore, the Partnership did not recognize an associated gain or loss.

Commodity Non-Trading Derivative Activity The marketing of energy related products and services exposes the Partnership to the fluctuations in the market values of exchanged instruments. The Partnership s marketing program is designed to realize margins related to fluctuations in commodity prices and differences in natural gas prices at various receipt and delivery points across the system for the Partnership s Natural Gas

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Services segment. DEFS manages the Partnership s marketing portfolios with strict policies which limit exposure to market risk.

12. Debt

Credit Facility with Financial Institutions On December 7, 2005, the Partnership entered into a 5-year credit agreement (the Credit Agreement), providing a $250 million revolving and a $100.1 million term loan facility. The Credit Agreement matures on December 7, 2010. The Credit Agreement prohibits the Partnership from making distributions of available cash to unitholders if any default or event of default (as defined in the Credit Agreement) exists. The Credit Agreement requires the Partnership to maintain at all times (commencing with the quarter ending March 31, 2006) a leverage ratio (the ratio of its consolidated indebtedness to its consolidated EBITDA, in each case as is defined by the credit agreement) of less than or equal to 4.75 to 1.0 (and on a temporary basis for not more than three consecutive quarters following the acquisition of assets in the midstream energy business of not more than 5.25 to 1.0); and maintain at the end of each fiscal quarter an interest coverage ratio (defined to be the ratio of adjusted EBITDA, as defined by the Credit Agreement to be earnings before interest, taxes and depreciation and amortization and other non-cash adjustments, for the four most recent quarters to interest expense for the same period) of greater than or equal to 3.0 to 1.0. The term loan bears interest at a rate equal to either LIBOR plus 0.15%, the Federal Funds rate plus 0.5%, or the Wachovia Bank prime rate. The revolving credit facility bears interest at a rate equal to LIBOR plus an applicable margin, which ranges from 0.27% to 1.025% based on leverage level and/or debt rating, or at the Wachovia Bank prime rate plus an applicable percentage based on leverage level and/or debt rating. At December 31, 2005, there was $110.0 million outstanding on the revolving credit facility and $100.1 million outstanding on the term loan facility, which is fully collateralized by high-grade securities. As of December 31, 2005, $0.8 million was recorded as accrued interest. No interest was paid during 2005. There were no letters of credit outstanding as of December 31, 2005. In December 2005, the Partnership incurred $0.7 million of debt issuance costs associated with the Credit Agreement. These expenses are deferred as other non-current assets in the accompanying consolidated balance sheet and will be amortized over the term of the Credit Agreement.

Long-term debt at December 31, 2005 and 2004 was as follows ($ in millions):

	Principal Amount 2005	Principal Amount 2004	Due Date	Interest Rate
Revolving credit facility	$ 110.0	$	December 7, 2010	Varies
Term loan facility	100.1		December 7, 2010	Varies
Long-term debt	$ 210.1	$		

Future maturities of long-term debt in the year indicated are as follows at December 31, 2005:

	Debt Maturities ($ in millions)	
2006	$	
2007		
2008		
2009		
2010		210.1
Thereafter		
Total long-term debt	$	210.1

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Estimated Fair Value of Financial Instruments

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

	December 31, 2005		December 31, 2004	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Restricted investments	$ 100.4	$ 100.4	$	$
Accounts receivable	$ 82.0	$ 82.0	$ 61.0	$ 61.0
Accounts payable	$ 87.0	$ 87.0	$ 39.8	$ 39.8
Unrealized gains (losses) on mark-to-market and hedging transactions	$ 0.6	$ 0.6	$ (0.1)	$ (0.1)
Long-term debt	$ 210.1	$ 210.1	$	$

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

The fair value of the non-trading derivative and hedging transactions is recorded on the consolidated balance sheets. The fair value is determined by multiplying the difference between the quoted termination prices for commodity contract prices by the quantities under contract.

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

14. Commitments and Contingent Liabilities

Litigation The Partnership is not a party to any significant legal proceedings but is a party to various administrative and regulatory proceedings that have arisen in the ordinary course of the Partnership s business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon the Partnership s future financial position, operations and cash flows.

Insurance DEFS carries insurance coverage which includes the assets and operations of the Partnership, with an affiliate of Duke Energy, that management believes is consistent with companies engaged in similar commercial operations with similar type properties. DEFS insurance coverage includes (1) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from operations; (2) workers compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) property insurance covering the replacement value of all real and personal property damage, including damages arising from boiler and machinery breakdowns, earthquake, flood damage and business interruption/extra expense; and (5) directors and officers insurance covering the performance of the Partnership s directors and officers duties as they relate to the Partnership. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations. DEFS also maintains excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are comparable to those carried by other energy companies of similar size. The cost of general insurance

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

coverages continued to fluctuate over the past year reflecting the changing conditions of the insurance markets.

A portion of the insurance costs described above are allocated by DEFS to the Partnership through the allocation methodology described in Note 7.

Environmental The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, the Partnership must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on the Partnership s consolidated results of operations, financial position or cash flows.

Indemnification DEFS will indemnify the Partnership for three years after the closing of the Partnership s initial public offering against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing date of the Partnership s initial public offering, on December 7, 2005. DEFS maximum liability for this indemnification obligation does not exceed $15.0 million and DEFS does not have any obligation under this indemnification until the Partnership s aggregate losses exceed $250,000. DEFS has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of the Partnership s initial public offering. The Partnership has agreed to indemnify DEFS against environmental liabilities related to the Partnership s assets to the extent DEFS is not required to indemnify the Partnership.

Other Commitments and Contingencies The Partnership utilizes assets under operating leases in several areas of operation. Consolidated rental expense, including leases with no continuing commitment, amounted to $1.3 million, $1.4 million and $1.0 million for the years ended December 31, 2005, 2004 and 2003, respectively. At December 31, 2005, minimum rental payments totaling $0.1 million under the Partnership s operating leases are scheduled to occur in 2006.

15. Business Segments

The Partnership s operations are located in the United States and are organized into two reporting segments: (1) Natural Gas Services; and (2) NGL Logistics.

Natural Gas Services The Natural Gas Services segment consists of the North Louisiana system assets, an integrated gas gathering, compression, treating, processing, and transportation system located in northern Louisiana and southern Arkansas that includes the Minden and Ada natural gas processing plants and gathering systems and the PELICO intrastate natural gas gathering and transportation pipeline.

NGL Logistics The NGL Logistics segment consists of the Seabreeze NGL transportation pipeline located along the Gulf Coast area of southeastern Texas and an interest in Black Lake FERC-regulated interstate NGL pipeline located in northern Louisiana and southeastern Texas of 50% in 2003, 2004 and the period from January 1, 2005 through December 6, 2005 and of 45% from December 7, 2005 through December 31, 2005, in line with the closing of the Partnership s initial public offering on December 7, 2005, whereby DEFS retained a 5% interest of Black Lake and an affiliate of BP owns the remaining interest and is the operator of Black Lake.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

These segments are monitored separately by management for performance against its internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment. The accounting policies for the segments are the same as those described in Note 2.

The following tables set forth the Partnership s segment information.

Year ended December 31, 2005 ($ in millions):

	Natural Gas Services	NGL Logistics	Other(b)	Total
Total operating revenues	$ 592.8	$ 191.7	$	$ 784.5
Gross margin(a)	$ 71.4	$ 3.8	$	$ 75.2
Operating and maintenance expense	(14.0)	(0.2)		(14.2)
Depreciation and amortization expense	(10.8)	(0.9)		(11.7)
General and administrative expense			(4.0)	(4.0)
General and administrative expense affiliate			(7.4)	(7.4)
Earnings from equity method investment		0.4		0.4
Interest income			0.5	0.5
Interest expense			(0.8)	(0.8)
Net income (loss)	$ 46.6	$ 3.1	$ (11.7)	$ 38.0
Capital expenditures	$ 7.9	$	$	$ 7.9

Year ended December 31, 2004 ($ in millions):

	Natural Gas Services	NGL Logistics	Other(b)	Total
Total operating revenues	$ 353.3	$ 156.2	$	$ 509.5
Gross margin(a)	$ 53.6	$ 3.3	$	$ 56.9
Operating and maintenance expense	(13.4)	(0.2)		(13.6)
Depreciation and amortization expense	(11.7)	(0.9)		(12.6)
General and administrative expense affiliate			(6.5)	(6.5)
Earnings from equity method investment		0.6		0.6

Impairment of equity method investment		(4.4)		(4.4)
Net income (loss)	$ 28.5	$ (1.6)	$ (6.5)	$ 20.4
Capital expenditures	$ 2.8	$ 0.3	$	$ 3.1

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Year ended December 31, 2003 ($ in millions):

	Natural Gas Services	NGL Logistics	Other(b)	Total
Total operating revenues	$ 343.7	$ 131.4	$	$ 475.1
Gross margin(a)	$ 42.2	$ 2.3	$	$ 44.5
Operating and maintenance expense	(14.7)	(0.3)		(15.0)
Depreciation and amortization expense	(11.9)	(0.9)		(12.8)
General and administrative expense affiliate			(7.1)	(7.1)
Earnings from equity method investment		0.4		0.4
Net income (loss)	$ 15.6	$ 1.5	$ (7.1)	$ 10.0
Capital expenditures	$ 2.4	$ 0.3	$	$ 2.7

The following table sets forth the Partnership s total assets segment information ($ in millions):

	December 31, 2005	December 31, 2004
Segment long-term assets:		
Natural Gas Services	$ 152.8	$ 154.9
NGL Logistics	23.5	25.1
Other(c)	106.5	
Total long-term assets	282.8	180.0
Current assets	124.5	61.1
Total assets	$ 407.3	$ 241.1

(a) Gross margin consists of total operating revenues less purchases of natural gas and NGLs. Gross margin is viewed as a non-Generally Accepted Accounting Principles (GAAP) measure under the rules of the Securities and Exchange Commission (SEC), but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of the Partnership s operating performance, Gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. The Partnership s

Gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Other consists of general and administrative expense.

(c) Other long-term assets not allocable to segments consist of restricted investments of $100.4 million, $5.4 million unrealized gain on non-trading derivative and hedging transactions and deferred offering costs of $0.7 million.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Quarterly Financial Data (Unaudited)

The Partnership s results of operations by quarter for the years ended December 31, 2005 and 2004 were as follows ($ in millions, except unit amounts):

2005	First	Second	Third	Fourth	Total
Total operating revenues	$ 127.4	$ 150.4	$ 233.1	$ 273.6	$ 784.5
Operating income	$ 6.9	$ 7.7	$ 3.4	$ 19.9	$ 37.9
Net income	$ 7.1	$ 7.8	$ 3.5	$ 19.6	$ 38.0
Basic net income per limited partner unit(a)	$	$	$	$ 0.20	$ 0.20

2004	First	Second	Third(b)	Fourth	Total
Total operating revenues	$ 116.3	$ 126.2	$ 126.8	$ 140.2	$ 509.5
Operating income	$ 6.9	$ 4.8	$ 6.2	$ 6.3	$ 24.2
Net income	$ 7.0	$ 5.0	$ 1.9	$ 6.5	$ 20.4
Basic net income per limited partner unit	$	$	$	$	$

(a) Total basic net income per limited partner unit calculated using net income of $3.5 million earned by the Partnership from December 7, 2005 through December 31, 2005. See Note 5.

(b) A $4.4 million impairment of equity method investment was recorded in the third quarter of 2004.

17. Subsequent Events

On January 25, 2006, the board of directors of DCP Midstream Partners general partner declared a prorated quarterly distribution of $0.095 per unit, payable on February 13, 2006 to unitholders of record on February 3, 2006, for the period from the close of the initial public offering of December 7, 2005 through December 31, 2005.

In February 2006, the Partnership announced plans to construct a new 37-mile NGL pipeline to connect a DEFS gas processing plant to the Seabreeze pipeline for a cost of approximately $12 million. The project is estimated to be completed during the fourth quarter of 2006 and is supported by a 10-year NGL product dedication by DEFS. Volumes from DEFS are estimated to be approximately 5.3 MBbls/d.

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

There were no changes in or disagreements with accountants on accounting and financial disclosures during the year ended December 31, 2005.

Item 9a. ***Controls and Procedures.***

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission s rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of December 31, 2005, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of December 31, 2005, our disclosure controls and procedures were effective. There were no significant changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9b. ***Other Information.***

No information was required to be disclosed in a report on Form 8-K, but not so reported, for the quarter ended December 31, 2005.

Part III

Item 10. ***Directors and Executive Officers of our General Partner.***

Management of DCP Midstream Partners, LP

We do not have directors or officers, which is commonly the case with publicly traded partnerships. Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is wholly-owned by DEFS. The officers and directors of our General Partner are responsible for managing us. All of the directors of our General Partner are elected annually by DEFS and all of the officers of our General Partner serve at the discretion of the directors. Unitholders are not entitled to participate, directly or indirectly, in our management or operations.

Board of Directors and Officers

The board of directors of our General Partner that oversees our operations has ten members, five of whom are independent as defined under the independence standards established by the New York Stock Exchange. The New York Stock Exchange does not require a listed limited partnership like us to have a majority of independent directors on its general partner s board of directors or to establish a compensation committee or a nominating committee. However, the board of our General Partner has established an audit committee consisting of three independent members of the board, a compensation committee and a special committee to address conflict situations.

The Named Executive officers of our General Partner manage the day-to-day affairs of our business and devote all of their time to our business and affairs. We also utilize a significant number of employees of DEFS to operate our business and provide us with general and administrative services.

Directors and Executive Officers

The following table shows information regarding the current directors and the Named Executive Officers of DCP Midstream GP, LLC. Directors are elected for one-year terms.

Name	Age	Position with DCP Midstream GP, LLC
Jim W. Mogg	57	Chairman of the Board
Michael J. Bradley	51	President, Chief Executive Officer and Director
Thomas E. Long	49	Vice President and Chief Financial Officer
Michael S. Richards	46	Vice President, General Counsel and Secretary
Greg K. Smith	39	Vice President, Business Development
William H. Easter III	56	Director
Paul F. Ferguson, Jr.	56	Director
John E. Lowe	47	Director
Milton Carroll	55	Director
Derrill Cody	67	Director
Frank A. McPherson	72	Director
Thomas C. Morris	65	Director
Michael J. Panatier	57	Director

Our directors hold office for one year or until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers.

Jim W. Mogg was elected Chairman of the Board of DCP Midstream GP, LLC in August 2005. Mr. Mogg is Group Vice President and Chief Development Officer of Duke Energy. Mr. Mogg assumed his current position in January 2004. He previously served as President and Chief Executive Officer of DEFS from December 1994 and Chairman, President and Chief Executive Officer of DEFS from 1999 through December 2003. In these capacities, Mr. Mogg was significantly involved in the development and growth of DEFS. From October 1997 until March 2005, Mr. Mogg also served as a director of the general partner of TEPPCO Partners, L.P. Mr. Mogg was appointed Chairman of the compensation committee of the general partner of TEPPCO Partners, L.P. in April 2000 and Chairman of the Board in May 2002.

Michael J. Bradley was elected President and Chief Executive Officer of DCP Midstream GP, LLC in August 2005 and director in November 2005. Mr. Bradley has been Group Vice President, Gathering and Processing of DEFS since July 2004. From April 2002 until July 2004, Mr. Bradley was Executive Vice President, Gathering and Processing of DEFS. From 1999 until April 2002, Mr. Bradley was Senior Vice President, Northern Division of DEFS. Mr. Bradley joined DEFS in 1994 and served as Senior Vice President. In these capacities, Mr. Bradley was significantly involved in the development and growth of DEFS. From February 2003 until March 2005, Mr. Bradley also served as a director of the general partner of TEPPCO Partners, L.P.

Thomas E. Long was elected Vice President and Chief Financial Officer of DCP Midstream GP, LLC in September 2005. Mr. Long has been Vice President of National Methanol Company, Duke Energy s international chemical joint venture, since December 2004. From April 2002 until December 2004, Mr. Long served as Vice President and Treasurer of DEFS. From April 1, 2000 until April 2002, Mr. Long served as Vice President, Investor Relations of DEFS. Mr. Long joined Duke Energy in 1979 and served in a variety of positions in accounting, finance, tax, investor relations and business development.

Michael S. Richards was elected Vice President, General Counsel and Secretary of DCP Midstream GP, LLC in September 2005. Mr. Richards was previously Assistant General Counsel and Assistant Secretary of DEFS since February 2000. He was previously Assistant General Counsel and Assistant Secretary at KN Energy, Inc. from December 1997 until he joined DEFS. Prior to that, he was Senior Counsel and Risk

Manager at Total Petroleum (North America) Ltd. from 1994 through 1997. Mr. Richards was previously in private practice where he focused on securities and corporate finance.

Greg K. Smith was elected Vice President, Business Development of DCP Midstream GP, LLC in September 2005. Mr. Smith was previously Vice President, Corporate Development of DEFS since June 2002. From July 1996 until June 2002, Mr. Smith held several positions at DEFS, including Commercial Director and Senior Attorney. Mr. Smith was previously an attorney with El Paso Natural Gas from 1992 until July 1996.

William H. Easter III was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Easter is Chairman of the Board, President and Chief Executive Officer of DEFS. Prior to joining DEFS in January 2004, Mr. Easter served as Vice President of State Government Affairs for ConocoPhillips from 2002 through 2003. From 1998 to 2002, Mr. Easter served as General Manager of the Gulf Coast business unit for Conoco Inc. and from 1992 to 1998 he served as Managing Director and Chief Executive Officer of Conoco Jet Nordic in Stockholm, Sweden. From March 2004 until March 2005, Mr. Easter served as a director of the general partner of TEPPCO Partners, L.P.

Paul F. Ferguson, Jr. was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Ferguson was a director of the general partner of TEPPCO Partners, L.P. from October 2004 until his resignation in 2005. Mr. Ferguson was a member of the Compensation, Audit and special committees of the general partner of TEPPCO Partners, L.P. He was elected Chairman of the audit committee in October 2004. He served as Senior Vice President and Treasurer of Duke Energy from June 1997 to June 1998, when he retired. Mr. Ferguson served as Senior Vice President and Chief Financial Officer of PanEnergy Corp. from September 1995 to June 1997. He held various other financial positions with PanEnergy Corp. from 1989 to 1995 and served as Treasurer of Texas Eastern Corporation from 1988 to 1989.

John E. Lowe was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Lowe is Executive Vice President, Planning, Strategy and Corporate Affairs of ConocoPhillips. He has responsibility for planning and strategic transactions, emerging businesses, government affairs and communications. Mr. Lowe previously served as Senior Vice President, Corporate Strategy and Development and was responsible for the forward strategy, development opportunities and public relations functions of Phillips Petroleum Company. He was named to this position in 2001 after serving as Senior Vice President of Planning and Strategic transactions in 2000 and Vice President of Planning and Strategic Transactions in 1999. Lowe currently serves on the board of directors for Chevron Phillips Chemical Company, DEFS, the Houston Museum of Natural Science and the National Association of Manufacturers. He is a certified public accountant.

Milton Carroll was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. Carroll is chairman of CenterPoint Energy, Inc., a Houston-based gas and electric utility where he has served as a director since 1992. Mr. Carroll is founder and chairman of Instrument Products, Inc., an oil-tool manufacturing company in Houston, Texas. He also serves as chairman of Healthcare Service Corporation and a director of Eagle Global Logistics, Inc. At various times from 1985 to 2005, he served on the boards of PanEnergy Corp., the Federal Reserve Bank of Houston and Dallas, Devon Energy Corporation, the general partner of TEPPCO Partners, L.P., and as chairman of both the Houston Endowment Foundation and the Texas Southern University Board of Regents. He is also a former Port Commissioner of the Port of Houston Authority.

Derrill Cody was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. Cody is presently of counsel to the law firm of Tomlinson & O Connell in Oklahoma City, Oklahoma since December 1, 2005. Prior to that he was of counsel to the law firm of McKinney & Stringer, P.C., in Oklahoma City from 1990. Mr. Cody served as executive vice president of Texas Eastern Corporation and chairman and chief executive officer of Texas Eastern Gas Pipeline Company in Houston, Texas. Prior to joining Texas Eastern in 1986, Mr. Cody held executive roles with both Kerr McGee Corporation and Texas Gas Resources Corporation prior to its merger with CSX Corporation. Mr. Cody currently serves on the board of CenterPoint Energy, Inc. and the board of regents of Seminole State College. He also previously served on the boards of the general partner of TEPPCO Partners, L.P.; Plains Petroleum Company from 1990 until its merger with Barrett Resources Corporation in 1995; and Barrett Resources Corporation from 1995 to 2001.

Frank A. McPherson was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. McPherson retired as chairman and chief executive officer from Kerr McGee Corporation in 1997 after a 40-year career with the company. Mr. McPherson was chairman and chief executive officer of Kerr McGee from 1983 to 1997. Prior to that he served in various capacities in management of Kerr McGee. Mr. McPherson joined Kerr McGee in 1957. Mr. McPherson serves on the boards of Integris Health, Tri Continental Corporation, Seligman Group of Mutual Funds, and several non-profit organizations in Oklahoma. He previously served on the boards of ConocoPhillips, Kimberly Clark Corporation, MAPCO Inc., Bank of Oklahoma, the Federal Reserve Bank of Kansas City, the Oklahoma State University Foundation Board of Trustees and the American Petroleum Institute.

Thomas C. Morris was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. Morris is currently retired, having served 34 years with Phillips Petroleum Company. Mr. Morris served in various capacities with Phillips, including vice president and treasurer and subsequently senior vice president and chief financial officer from 1994 until his retirement in 2001. Mr. Morris served as vice chairman of the board of OK Mozart, is a former member of the executive board of the American Petroleum Institute finance committee and a former member of the Business Development Council of Texas A&M University.

Michael J. Panatier was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. Panatier served as a director of DEFS from March 2000 until his resignation in August 2002 and was vice chairman of the board of DEFS through 2001. Mr. Panatier held several executive roles at Phillips Petroleum Company and its subsidiaries, including executive vice president of refining, marketing and transportation through 2002, senior vice president of gas processing and marketing from 1998 until 2000, and president and chief executive officer of GPM Gas Corporation from 1994 until 2000.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires DCP Midstream GP, LLC s directors and executive officers, and persons who own more than 10% of any class of our equity securities to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of our common units and our other equity securities. Specific due dates for those reports have been established, and we are required to report herein any failure to file reports by those due dates. Directors, executive officers and greater than 10% unitholders are also required by SEC regulations to furnish us with copies of all Section 16(a) reports they file.

To our knowledge, based solely on a review of the copies of reports furnished to us and written representations that no other reports were required during the fiscal year ended December 31, 2005, all Section 16(a) filing requirements applicable to such reporting persons were complied with except that Mr. Bradley filed a late Form 4 reporting the disposition of 19 common units to our employees, officers and/or board members for the issuance of commemorative common unit certificates associated with our initial public offering and each of Messrs. Mogg, Long, Richards, Smith, Easter, Ferguson, and Lowe filed a late Form 4 and each of Messrs. Carroll, Cody, McPherson, Morris and Panatier filed an amended Form 3, all reporting the acquisition of one commemorative common unit issued as part of our initial public offering. In addition Messrs. Bradley, Long, Richards, Smith, Ferguson, Carroll, Cody, McPherson, Morris and Panatier filed a late Form 4 reporting the acquisition of phantom units in January 2006 under our Long-Term Incentive Plan.

Audit Committee

The board of directors of DCP Midstream GP, LLC has a standing audit committee. The audit committee is composed of three directors, Paul Ferguson, Frank McPherson and Thomas Morris, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. The board has determined that each member of the audit committee is independent under

Section 303A.02 of the New York Stock Exchange listing standards and Section 10A(m)(3) of the Securities Exchange Act of 1934, as amended. In making the independence determination, the board considered the requirements of the New York Stock Exchange and our Code of Business Ethics. Among other factors, the board considered current or previous employment with the Partnership, its auditors or their affiliates by the director or his immediate family members, ownership of our voting securities, and other material relationships with the Partnership. The audit committee has adopted a charter, which has been ratified and approved by the board of directors.

With respect to material relationships, the following relationships are not considered to be material for purposes of assessing independence: service as an officer, director, employee or trustee of, or greater than five percent beneficial ownership in (a) a supplier to the partnership if the annual sales to the partnership are less than one percent of the sales of the supplier; (b) a lender to the partnership if the total amount of the partnership s indebtedness is less than one percent of the total consolidated assets of the lender; or (c) a charitable organization if the total amount of the partnership s annual charitable contributions to the organization are less than three percent of that organization s annual charitable receipts.

Mr. Ferguson has been designated by the board as the audit committee s financial expert meeting the requirements promulgated by the SEC and set forth in Item 401(h) of Regulation S-K of the Securities Exchange Act of 1934 based upon his education and employment experience as more fully detailed in Mr. Ferguson s biography set forth above.

Special Committee

The board of directors of our General Partner has a standing special committee, which is comprised of four directors, Frank McPherson, Milton Carroll, Paul Ferguson and Thomas Morris. The special committee will review specific matters that the board believes may involve conflicts of interest. The special committee will determine if the resolution of the conflict of interest is fair and reasonable to us. The members of the special committee may not be officers or employees of our General Partner or directors, officers or employees of its affiliates. Each of the members of the special committee meet the independence and experience standards established by the New York Stock Exchange and the Securities Exchange Act of 1934, as amended. Any matters approved by the special committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our General Partner of any duties it may owe us or our unitholders.

Compensation Committee

The board of directors of our General Partner has a standing compensation committee, which is composed of six directors, Jim Mogg, Milton Carroll, Derrill Cody, William Easter, Frank McPherson and Michael Panatier. The compensation committee oversees compensation decisions for the officers of our general partner and administers the long-term incentive plan, selecting individuals to be granted equity-based awards from among those eligible to participate. The compensation committee has adopted a charter, which has been ratified and approved by the board of directors.

Code of Business Ethics

We have adopted a Code of Business Ethics applicable to the persons serving as our directors, officers (including without limitation, the chief executive officer, chief financial officer and principal accounting officer) and employees, which includes the prompt disclosure to the SEC of a current report on Form 8-K of any waiver of the code for executive officers or directors approved by the board of directors. A copy of our Code of Business Ethics is available free of charge in print to any unitholder who sends a request to the office of the Secretary of DCP Midstream Partners, LP at 370 17th Street, Suite 2775, Denver, Colorado 80202. The Code of Business Ethics is also posted on our website at *www.dcppartners.com.*

Communications by Unitholders

Unitholders may communicate with any and all members of our board by transmitting correspondence by mail or facsimile addressed to one or more directors by name or to the chairman of the board at the following address and fax number; Name of the Director(s), c/o Secretary, DCP Midstream Partners, LP, 370 17th Street, Suite 2775, Denver, Colorado 80202.

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Item 11. ***Executive Compensation.***

Executive Compensation

The aggregate amount of base compensation paid to the Named Executive Officers for services rendered to us for the period from December 7, 2005, the date of our initial public offering, through December 31, 2005 was approximately $55,000.

Our General Partner and DCP Midstream GP, LLC were formed in August 2005. Accordingly, DCP Midstream GP, LLC has not accrued any obligations with respect to management incentive or retirement benefits for its directors and officers for the 2004 or 2005 fiscal years. Our General Partner currently has nine employees including the Chief Executive Officer, the Chief Financial Officer, the general counsel, a senior business development executive and support staff. The officers and employees of our General Partner may participate in employee benefit plans and arrangements sponsored by DEFS. Our General Partner has not entered into any employment agreements with any of its officers. The board of directors granted awards to our key employees and our outside directors pursuant to the Long-Term Incentive Plan in January 2006.

Compensation of Directors

On February 8, 2006, the board of directors of our General Partner approved a compensation package for directors who are not officers or employees of affiliates of the General Partner (Non-Employee Directors). Members of the board who are also officers or employees of affiliates of our General Partner do not receive additional compensation for serving on the board. The board approved the payment to each Non-Employee Director of an annual compensation package containing the following: (i) a $35,000 retainer; (ii) a board meeting fee of $1,000 for each board meeting attended; (iii) a telephonic board meeting fee of $500 for each telephonic meeting attended; (iv) an initial grant of 2,000 phantom units, under the Partnership s Long-Term Incentive Plan, that represent an approximate equivalent value of common units representing limited partnership interests in the Partnership; and (v) following the first year, an annual grant of 1,000 phantom units, under the Partnership s Long-Term Incentive Plan, that represent an approximate equivalent value of common units representing limited partnership interests in the Partnership. The grant of phantom units will vest ratably over three years. In addition, the Chair of the audit committee of the board will receive an annual retainer of $20,000 and the members of the audit committee will receive $1,500 for each audit committee meeting attended. The Chair of the special committee of the Board will likewise receive an annual retainer of $20,000 and the members of the special committee will receive $1,000 for each special committee meeting attended. Finally, the members of the compensation committee will receive $1,000 for each compensation committee meeting attended. Such directors will also be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors and committees. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Long-Term Incentive Plan

A complete description of our long-term incentive plan is incorporated herein by reference to Note 2 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.***

The following table sets forth the beneficial ownership of our units and the related transactions held by:

each person who beneficially owns 5% or more of our outstanding units as of February 17, 2006;

all of the directors of DCP Midstream GP, LLC;

each Named Executive Officer of DCP Midstream GP, LLC; and

all directors and Named Executive Officers of DCP Midstream GP, LLC as a group.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common and Subordinated Units Beneficially Owned
Duke Energy Field Services, LLC(2)	7,143	*	7,142,857	100%	40.0%
DCP LP Holdings, LP(3)	7,143	*	7,142,857	100%	40.0%
Williams, Jones & Associates, Inc.(4)	911,500	8.8%			8.8%
Jim W. Mogg	13,001	*			*
Michael J. Bradley	15,081	*			*
Thomas E. Long	22,501	*			*
Michael S. Richards	1,501	*			*
Greg K. Smith	5,001	*			*
William H. Easter III	3,501	*			*
Paul F. Ferguson, Jr.	1,001	*			*
John E. Lowe	10,001	*			*
Milton Carroll	3,001	*			*
Derrill Cody	15,001	*			*
Frank A. McPherson	5,001	*			*
Thomas C. Morris	5,001	*			*
Michael J. Panatier	5,001	*			*
All directors and executive officers as a group (13 persons)	104,593	*			*

* Less than 1%.

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 370 17th Street, Suite 2775, Denver, Colorado 80202.

(2) Duke Energy Field Services is the ultimate parent company of DCP LP Holdings, LP and may, therefore, be deemed to beneficially own the units held by DCP LP Holdings, LP. Duke Energy Field Services disclaims beneficial ownership of all of the units owned by DCP LP Holdings, LP. The address of Duke Energy Field Services is 370 17th Street, Suite 2500, Denver, Colorado 80202.

(3) The address of DCP LP Holdings, LP is 370 17th Street, Suite 2500, Denver, Colorado 80202.

(4) As set forth in a Schedule 13G filed on January 18, 2006. The address of Williams, Jones & Associates, Inc. is 717 Fifth Avenue, New York, New York 10022.

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Equity Compensation Plan Information

The following table summarizes information about our equity compensation plan as of December 31, 2005.

	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights(1) (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column(a)) (c)
Equity compensation plans approved by unitholders		$	
Equity compensation plans not approved by unitholders			
Total		$	

(1) The long-term incentive plan currently permits the grant of awards covering an aggregate of 850,000 units. For more information on our long-term incentive plan, which did not require approval by our limited partners, refer to Item 11. Executive Compensation Long-Term Incentive Plan.

Item 13. ***Certain Relationships and Related Transactions.***

Distributions and Payments to our General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our formation, ongoing operation, and liquidation. These distributions and payments are determined by and among affiliated entities and, consequently, are not the result of arm s-length negations.

Formation Stage:	
The consideration received by our General Partner and its affiliates for the contribution of the assets and liabilities	7,143 common units; 7,142,857 subordinated units; 2% general partner interest in DCP Midstream GP, LP; The incentive distribution rights; and $8.6 million cash payment from the proceeds of the offering and borrowings under our new credit facility, in part to reimburse them for certain capital expenditures.

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Operational Stage:	
Distributions of available cash to our General Partner and its affiliates	We will generally make cash distributions 98% to the unitholders and 2% to our General Partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level. For the period from December 7, 2005, the date of our initial public offering, through December 31, 2005, we made a prorated distribution of $0.095 per unit to our unitholders, including DEFS and its affiliates. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $0.5 million on the 2% general partner interest and approximately $10.0 million on their common units and subordinated units.
Payments to our General Partner and its affiliates	We reimburse DEFS and its affiliates up to $4.8 million per year for the provision of various general and administrative services for our benefit. For further information regarding the reimbursement, please see the Omnibus Agreement section below.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage:	
Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Omnibus Agreement

The employees supporting our operations are employees of DEFS. We are required to reimburse DEFS for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs and taxes. DEFS also provides centralized corporate functions on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. DEFS records the accrued liabilities and prepaid expenses for most general and administrative expenses in its financial statements, including liabilities related to payroll, short and long-term incentive plans, employee retirement and medical plans, paid time off, audit, tax, insurance and other service fees. Our share of those costs has been allocated based on our proportionate net investment (consisting of property, plant and equipment, net, equity method investment, and intangible assets, net) compared to DEFS net investment. In management s estimation, the allocation methodologies used are reasonable and result in an allocation to us of our costs of doing business borne by DEFS.

Upon the closing of our initial public offering, we entered into an Omnibus Agreement with DEFS, our General Partner and others that addresses the following matters:

our obligation to reimburse DEFS the payment of operating expenses, including salary and benefits of operating personnel, it incurs on our behalf in connection with our business and operations;

our obligation to reimburse DEFS for providing us general and administrative services with respect to our business and operations, which is capped at a maximum of $4.8 million, subject to an increase for 2007 and 2008 based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of our special committee;

our obligation to reimburse DEFS for insurance coverage expenses it incurs with respect to our business and operations and with respect to director and officer liability coverage;

DEFS obligation to indemnify us for certain liabilities and our obligation to indemnify DEFS for certain liabilities;

DEFS obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements are in effect as of the closing of our initial public offering until the earlier to occur of the fifth anniversary of the closing of our initial public offering or such time as we obtain an investment grade credit rating from either Moody s Investor Services, Inc. or Standard & Poor s Ratings Group with respect to any of our unsecured indebtedness; and

DEFS 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 our business or operations that are in effect at the closing of our initial public offering until the expiration of such contracts.

Our General Partner and its affiliates will also receive payments from us pursuant to the contractual arrangements described below under the caption Contracts with Affiliates.

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

Reimbursement of Operating and General and Administrative Expense

Under the Omnibus Agreement we reimburse DEFS for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit with respect to the assets contributed to us at the closing of our initial public offering. The Omnibus Agreement provides that we will reimburse DEFS for our allocable portion of the premiums on insurance policies covering our assets.

Pursuant to these arrangements, DEFS performs centralized corporate functions for us, such as legal, accounting, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. We will reimburse DEFS for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as salaries of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits.

Competition

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

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Indemnification

Under the Omnibus Agreement, DEFS will indemnify us for three years after the closing of our initial public offering against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing date of our initial public offering. DEFS maximum liability for this indemnification obligation does not exceed $15 million and DEFS does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DEFS has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DEFS against environmental liabilities related to our assets to the extent DEFS is not required to indemnify us.

Additionally, DEFS will indemnify us for losses attributable to title defects, retained assets and liabilities (including preclosing litigation relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DEFS for all losses attributable to the postclosing operations of the assets contributed to us, to the extent not subject to DEFS indemnification obligations. In addition, DEFS 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 2005 through 2007. DEFS has also agreed to indemnify us for 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 scheduled pipeline integrity testing occurring in 2006 and 2007.

Contracts with Affiliates

We charge transportation fees, sell a portion of our residue gas and NGLs to, and purchase raw natural gas and NGLs from, DEFS, ConocoPhillips, and their respective affiliates. Management anticipates continuing to purchase and sell these commodities to DEFS, ConocoPhillips and their respective affiliates in the ordinary course of business.

Natural Gas Gathering and Processing Arrangements

We have a fee-based contractual relationship with ConocoPhillips, which includes multiple contracts, pursuant to which ConocoPhillips has dedicated all of its natural gas production within an area of mutual interest to our Ada, Minden and PELICO systems under multiple agreements that have terms of up to five years and are market based. These agreements provide for the gathering, processing and transportation services at our Ada and Minden gathering and processing systems and the PELICO system. At our Ada gathering and processing system, we collect fees from ConocoPhillips for gathering and compressing the natural gas from the wellhead or receipt point and processing the natural gas at the Ada processing plant. At our Minden gathering and processing system, we purchase natural gas from ConocoPhillips at the wellhead or receipt point, transport the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs at index prices based on published index market prices. At our PELICO system, we collect fees for compression and transportation services. Please read Business Natural Gas Services Segment Customers and Contracts and DCP Midstream Partners, LP Notes to Consolidated Financial Statements Agreements and Transactions with Affiliates.

One of these arrangements is set forth in a natural gas gathering agreement dated June 1, 1987, as amended, between DEFS Assets Holding, LP (successor to the interest of Cornerstone Natural Gas Company) and ConocoPhillips (successor to interest of Phillips Petroleum Company). We succeeded to the rights and obligations of DEFS Assets Holding, LP under this agreement upon the closing of our initial public offering. Pursuant to this agreement, we receive gathering and compression fees from ConocoPhillips with respect to natural gas produced by ConocoPhillips that we gather and compress in our Ada gathering system from wells located in a designated area of mutual interest located in northern Louisiana covering approximately 54 square miles. The fees we receive are based on market rates for these types of services. To date, ConocoPhillips has drilled and connected approximately 145 wells to our Ada gathering system pursuant to this contract. This agreement expires in 2011.

Merchant Arrangements

Under our merchant arrangements, we use a subsidiary of DEFS (Duke Energy Field Services Marketing, LP) as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas primarily to third parties. In the case of certain industrial end-user customers, from time to time we may sell aggregated natural gas to a subsidiary of DEFS which in turn would resell natural gas to these customers. Under these arrangements, we expect that this subsidiary of DEFS would make a profit on these sales. We also have entered into a contractual arrangement with a subsidiary of DEFS (Duke Energy Field Services Marketing, LP) that provides that DEFS will purchase natural gas and transport it into our PELICO system where we will buy the gas from DEFS at their weighted average cost plus a contractually agreed to marketing fee. In addition, for a significant portion of the gas that we sell out of our PELICO system, we have entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase that natural gas from us and transport it to a sales point at a price equal to their net weighted average sales price less a contractually agreed to marketing fee. We also sell our NGLs at the Minden processing plant to a subsidiary of DEFS (Duke Energy NGL Services, LP) who then transports the NGLs on the Black Lake pipeline. We have also entered into a fixed price natural gas purchase arrangement with a third party customer. In connection with this third party arrangement, we have also entered into a financial hedging arrangement with a subsidiary of DEFS (Duke Energy Field Services Marketing, LP). Under this hedging arrangement, we have reduced the fixed price risk related to the third party arrangement. These arrangements will settle in March 2006. Through October 2005, we had a condensate sales agreement with TEPPCO Partners L.P. where we sold substantially all of our condensate to them under a market-based agreement. In February 2005, DEFS sold its interest in TEPPCO Partners L.P. and as such the revenues are no longer accounted for as affiliate transactions. Please read DCP Midstream Partners, LP Notes to Consolidated Financial Statements Agreements and Transactions with Affiliates.

Transportation Arrangements

Effective December 2005, we entered into a contractual arrangement with a subsidiary of DEFS (Duke Energy NGL Services, LP) that provided that the DEFS subsidiary will pay us to transport NGLs on our Seabreeze pipeline pursuant to a fee-based rate that will be applied to the volumes transported. This fee-based contract, as amended, is a 17-year transportation agreement expiring in 2022. Under this agreement, we are required to reserve sufficient capacity in the Seabreeze pipeline to ensure our ability to accept up to 38,000 Bbls/d of NGLs tendered by the DEFS subsidiary each day prior to utilizing the excess capacity for our own use or for that of any third parties, and the DEFS subsidiary is required to tender all NGLs processed at certain plants that it owns, controls or otherwise has an obligation to market for others. DEFS historically is also the largest shipper on the Black Lake pipeline, primarily due to the NGLs delivered to it from our Minden processing plant. Please read DCP Midstream Partners, LP Notes to Consolidated Financial Statements Agreements and Transaction with Affiliates.

Hedging Arrangements

We have entered into long-term natural gas and crude oil swap contracts whereby we receive a fixed price for natural gas and crude oil and we pay a floating price. DEFS has issued guarantees to our counterparties in these transactions. With this credit support, we have more favorable collateral terms than we would have otherwise received. For more information regarding our hedging activities and credit support provided by DEFS, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies and Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Item 14. ***Principal Accounting Fees and Services.***

The following table presents fees for professional services rendered by Deloitte & Touche LLP (Deloitte), our principal accountant, for the audit of our financial statements for the year ended December 31, 2005, and the fees billed for other services rendered by Deloitte during the year:

Type of Fees	**2005 ($ in millions)**	
Audit Fees(a)	$	2.3
Audit-Related Fees	$	
Tax Fees	$	
All Other Fees	$	
Total Fees	$	2.3

(a) Audit Fees are fees billed by Deloitte for professional services for the audit of our consolidated financial statements included in our annual report on Form 10-K and review of financial statements included in our quarterly reports on Form 10-Q, services that are normally provided by Deloitte in connection with statutory and regulatory filings or engagements or any other service performed by Deloitte to comply with generally accepted auditing standards and include comfort and consent letters in connection with Securities and Exchange Commission filings and financing transactions.

Audit Committee Pre-Approval Policy

The audit committee pre-approves all audit and permissible non-audit services provided by the independent auditors on a case-by-case basis. These services may include audit services, audit-related services, tax services and other services. The audit committee does not delegate its responsibilities to pre-approve services performed by the independent auditor to management or to an individual member of the audit committee. The audit committee may, however, from time to time delegate its authority to the audit committee Chairman, who reports on the independent auditor services approved by the Chairman at the next audit committee meeting.

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Part IV

Item 15. ***Exhibits and Financial Statement Schedules.***

(a) *Financial Statement Schedules.*

DCP MIDSTREAM PARTNERS, LP

SCHEDULE II CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Deductions/ Other	Credit to Consolidated Statements of Operations	Balance at End of Period
			($ in millions)		
December 31, 2005					
Allowance for doubtful accounts	$ 0.2	$	$	$ (0.1)	$ 0.1
Environmental		0.2	(0.1)		0.1
Other(a)	1.3		(1.3)		
	$ 1.5	$ 0.2	$ (1.4)	$ (0.1)	$ 0.2
December 31, 2004					
Allowance for doubtful accounts	$ 0.2	$	$	$	$ 0.2
Environmental					
Other(a)	1.3				1.3
	$ 1.5	$	$	$	$ 1.5
December 31, 2003					
Allowance for doubtful accounts	$ 0.2	$	$	$	$ 0.2
Environmental		0.1	(0.1)		
Other(a)		1.3			1.3
	$ 0.2	$ 1.4	$ (0.1)	$	$ 1.5

(a) Principally consists of other contingency liabilities which are included in other current liabilities.

(b) *Exhibits.*

A list of exhibits required by Item 601 of Regulation S-K to be filed as part of this report:

Exhibit Number	Description
1.1**	Underwriting Agreement, dated December 1, 2005 among Duke Energy Field Services, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, DCP Midstream GP, LLC, DCP Midstream Operating, LP and Lehman Brothers Inc. and Citigroup Global Markets Inc. as representatives of the several underwriters named therein.
3.1**	Amended and Restated Limited Partnership Agreement of DCP Midstream Partners, LP.
3.2**	First Amended and Restated Limited Partnership Agreement of DCP Midstream GP, LP.
3.3**	First Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC.
10.1**	Omnibus Agreement, dated December 7, 2005, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP.
10.2**	DCP Midstream Partners, LP Long-Term Incentive Plan.

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Exhibit Number	Description
10.3**	Contribution, Conveyance and Assumption Agreement, dated December 7, 2005, among DCP Midstream Partners, LP, DCP Midstream Operating, LP, DCP Midstream GP, LLC, DCP Midstream GP, LP, Duke Energy Field Services, LLC, DEFS Holding 1, LLC, DEFS Holding, LLC, DCP Assets Holdings, LP, DCP Assets Holdings GP, LLC, Duke Energy Guadalupe Pipeline Holdings, Inc., Duke Energy NGL Services, LP, DCP LP Holdings, LP and DCP Black Lake Holdings, LLC.
10.4**	Credit Agreement, dated December 7, 2005, between DCP Midstream Operating, LP and Wachovia Bank, National Association, as administrative agent for the lenders named therein.
10.5*	Natural Gas Gathering Agreement, dated June 1, 1987, as amended, between DEFS Assets Holding, LP, successor to the interest of Cornerstone Natural Gas Company and ConocoPhillips, successor to the interest of Phillips Petroleum Company.
21.1	List of Subsidiaries of DCP Midstream Partners, LP.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Incorporated by reference from DCP Midstream Partners, LP Amendment No. 2 to Registration Statement on Form S-1 filed with the Securities and Exchange Commission on November 18, 2005 (File No. 333-128378).

** Incorporated by reference from DCP Midstream Partners, LP Form 8-K filed with the Securities and Exchange Commission on December 12, 2005 (File No.001-32678).

Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

SIGNATURES

Pursuant to the requirements of the Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on March 1, 2006.

DCP Midstream Partners, LP

its General Partner	By:	DCP Midstream GP, LP
its General Partner	By:	DCP Midstream GP, LLC
	By:	/s/ Michael J. Bradley

Name: Michael J. Bradley
Title: President and Chief Executive Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS that each person whose signature appears below constitutes and appoints Michael J. Bradley as his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or in his name, place, and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this annual report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ Michael J. Bradley Michael J. Bradley	President, Chief Executive Officer and Director (Principal Executive Officer)	March 1, 2006
/s/ Thomas E. Long Thomas E. Long	Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2006
/s/ Patrick J. Welch Patrick J. Welch	Vice President and Controller (Principal Accounting Officer)	March 1, 2006
/s/ Jim W. Mogg	Chairman of the Board	March 1, 2006

Jim W. Mogg

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Signature	Title	Date
/s/ William H. Easter III William H. Easter III	Director	March 1, 2006
/s/ Paul F. Ferguson, Jr. Paul F. Ferguson, Jr.	Director	March 1, 2006
/s/ John E. Lowe John E. Lowe	Director	March 1, 2006
/s/ Milton Carroll Milton Carroll	Director	March 1, 2006
/s/ Derrill Cody Derrill Cody	Director	March 1, 2006
/s/ Frank A. McPherson Frank A. McPherson	Director	March 1, 2006
/s/ Thomas C. Morris Thomas C. Morris	Director	March 1, 2006
/s/ Michael J. Panatier Michael J. Panatier	Director	March 1, 2006

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Portions of this exhibit have been omitted pursuant to a request for confidential treatment.