

DCP Midstream Partners, LP
Form 10-Q
May 10, 2007
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended: March 31, 2007

or

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

For the transition period from _____ to _____

Commission File Number: 001-32678

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

370 17th Street, Suite 2775

03-0567133
(I.R.S. Employer

Identification No.)

80202

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Denver, Colorado
(Address of principal executive offices)

(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark 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 Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer

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

As of May 7, 2007, there were outstanding 10,357,143 common limited partner units, 200,312 Class C units, and 7,142,857 subordinated units.

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DCP MIDSTREAM PARTNERS, LP

FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2007

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GLOSSARY OF TERMS

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

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

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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, plan, forecast and other similar words.

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in Item 1A. Risk Factors in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2006, as well as the following risks and uncertainties:

the level and success of natural gas drilling around our assets, and our ability to connect supplies to our gathering and processing systems in light of competition;

our ability to grow through acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;

our ability to access the debt and equity markets, which will depend on general market conditions, interest rates and our ability to effectively hedge such rates with derivative financial instruments to limit a portion of the adverse effects of potential changes in interest rates, and the credit ratings for our debt obligations;

the extent of changes in commodity prices, our ability to effectively hedge to limit a portion of the adverse impact of potential changes in prices through derivative financial instruments, and the potential impact of price on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;

our ability to purchase propane from our principal suppliers for our wholesale propane logistics business;

our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required building, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for supplies;

the creditworthiness of counterparties to our transactions;

weather and other natural phenomena, including their potential impact on demand for the commodities we sell and our and third-party-owned infrastructure;

changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the increased regulation of our industry;

industry changes, including the impact of consolidations, alternative energy sources, technological advances and changes in competition;

the amount of collateral required to be posted from time to time in our transactions; and

general economic, market and business conditions.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Table of Contents**PART I. FINANCIAL INFORMATION****Item 1. Financial Statements**

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2007	December 31, 2006
	(\$ in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 29.4	\$ 46.2
Short-term investments	2.0	0.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of \$0.3 million at both periods	40.1	43.4
Affiliates	28.0	34.8
Inventories	29.9	30.1
Unrealized gains on non-trading derivative and hedging instruments	1.9	4.2
Deposits	9.0	
Other	0.3	0.3
Total current assets	140.6	159.6
Restricted investments	102.0	102.0
Property, plant and equipment, net	193.6	194.7
Goodwill	29.3	29.3
Intangible assets, net	2.7	2.8
Equity method investments	6.1	5.9
Unrealized gains on non-trading derivative and hedging instruments	4.3	6.5
Other non-current assets	0.8	0.8
Total assets	\$ 479.4	\$ 501.6
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	\$ 75.7	\$ 66.9
Affiliates	20.7	50.4
Unrealized losses on non-trading derivative and hedging instruments	1.8	0.7
Accrued interest payable	0.8	1.1
Other	6.0	7.4
Total current liabilities	105.0	126.5
Long-term debt	268.0	268.0
Unrealized losses on non-trading derivative and hedging instruments	3.8	2.7
Other long-term liabilities	1.2	1.0
Total liabilities	378.0	398.2

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Commitments and contingent liabilities

Partners' equity:		
Common unitholders (10,357,143 units issued and outstanding at both periods)	226.1	223.4
Class C unitholders (200,312 units issued and outstanding at both periods)	(20.6)	(20.7)
Subordinated unitholders (7,142,857 convertible units issued and outstanding at both periods)	(99.6)	(101.6)
General partner interest	(4.9)	(5.0)
Accumulated other comprehensive income	0.6	7.3
Total	101.6	103.4
Less treasury units: 4,000 and 0, respectively; at cost	0.2	
Total partners' equity	101.4	103.4
Total liabilities and partners' equity	\$ 479.4	\$ 501.6

See accompanying notes to condensed consolidated financial statements.

Table of Contents**DCP MIDSTREAM PARTNERS, LP****CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS****(Unaudited)**

	Three Months Ended	
	March 31,	
	2007	2006
	(\$ in millions, except per unit amounts)	
Operating revenues:		
Sales of natural gas, propane, NGLs and condensate	\$ 178.3	\$ 184.1
Sales of natural gas, propane, NGLs and condensate to affiliates	54.6	74.9
Transportation and processing services	3.3	3.8
Transportation and processing services to affiliates	4.0	2.7
Losses from non-trading derivative activity affiliates	(0.1)	(0.1)
Total operating revenues	240.1	265.4
Operating costs and expenses:		
Purchases of natural gas, propane and NGLs	163.1	210.5
Purchases of natural gas, propane and NGLs from affiliates	47.8	31.4
Operating and maintenance expense	6.6	6.4
Depreciation and amortization expense	3.4	3.3
General and administrative expense	2.5	2.8
General and administrative expense affiliates	2.3	1.9
Total operating costs and expenses	225.7	256.3
Operating income	14.4	9.1
Interest income	1.7	1.5
Interest expense	3.8	2.6
Earnings from equity method investments	0.2	
Net income	\$ 12.5	\$ 8.0
Less:		
Net income attributable to predecessor operations		(2.6)
General partner interest in net income	(0.3)	(0.1)
Net income allocable to limited partners	\$ 12.2	\$ 5.3
Net income per limited partner unit basic and diluted	\$ 0.58	\$ 0.30
Weighted-average limited partner units outstanding basic and diluted	17.7	17.5
See accompanying notes to condensed consolidated financial statements.		

Table of Contents**DCP MIDSTREAM PARTNERS, LP****CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME****(Unaudited)**

	Three Months Ended March 31,	
	2007	2006
	(\$ in millions)	
Net income	\$ 12.5	\$ 8.0
Other comprehensive loss:		
Reclassification of cash flow hedge into earnings	(1.4)	(0.2)
Net unrealized losses on cash flow hedges	(5.3)	(0.4)
Total other comprehensive loss	(6.7)	(0.6)
Total comprehensive income	\$ 5.8	\$ 7.4

See accompanying notes to condensed consolidated financial statements.

Table of Contents**DCP MIDSTREAM PARTNERS, LP****CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

	Three Months Ended March 31,	
	2007	2006
	(\$ in millions)	
OPERATING ACTIVITIES:		
Net income	\$ 12.5	\$ 8.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	3.4	3.3
Undistributed earnings from equity method investments	(0.2)	
Other, net	(0.5)	(0.7)
Change in operating assets and liabilities which provided (used) cash:		
Accounts receivable	10.8	41.6
Inventories	0.2	26.0
Net unrealized losses on non-trading derivative and hedging instruments	0.1	0.3
Accounts payable	(10.2)	(71.4)
Accrued interest	(0.3)	(0.2)
Other current assets and liabilities	(1.8)	1.2
Other non-current assets and liabilities	0.2	0.1
Net cash provided by operating activities	14.2	8.2
INVESTING ACTIVITIES:		
Capital expenditures	(3.4)	(4.7)
Payment of earnest deposit	(9.0)	
Proceeds from sales of assets		0.1
Purchases of available-for-sale securities	(5,661.3)	(2,337.8)
Proceeds from sales of available-for-sale securities	5,660.4	2,337.4
Net cash used in investing activities	(13.3)	(5.0)
FINANCING ACTIVITIES:		
Repayments of debt		(20.0)
Purchase of treasury units	(0.2)	
Excess purchase price over acquired assets	(9.9)	
Net change in advances from DCP Midstream, LLC		(10.5)
Distributions to unitholders	(7.8)	(1.7)
Contributions from unitholders	0.2	
Net cash used in financing activities	(17.7)	(32.2)
Net change in cash and cash equivalents	(16.8)	(29.0)
Cash and cash equivalents, beginning of period	46.2	42.2
Cash and cash equivalents, end of period	\$ 29.4	\$ 13.2
Supplementary disclosure of cash flow information:		
Cash paid for interest expense, net of capitalized interest	\$ 4.3	\$ 2.7

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Description of Business and Basis of Presentation

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

We are a Delaware master limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our North Louisiana system assets, or Minden, Ada, and Pelico; our NGL transportation pipelines, or Seabreeze, Wilbreeze (which was completed in December 2006), and our 45% equity method investment in Black Lake Pipe Line Company, or Black Lake; and our wholesale propane logistics business that we acquired on November 1, 2006 from DCP Midstream, LLC.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, which is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips.

In November 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC in a transaction among entities under common control. Accordingly, our financial information now includes the historical results of our wholesale propane logistics business for each period presented.

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. We refer to the assets, liabilities and operations of our wholesale propane logistics business prior to our acquisition from DCP Midstream, LLC in November 2006, as our predecessor. The condensed consolidated financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity. All significant intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations have been identified in the condensed consolidated financial statements as transactions between affiliates.

The accompanying unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission, or SEC. Accordingly these condensed consolidated financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective interim periods. Certain information and notes normally included in our annual financial statements have been condensed or omitted from these interim financial statements pursuant to such rules and regulations. These condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2006.

2. Summary of Significant Accounting Policies

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

Short-Term and Restricted Investments Short-term investments consist of \$2.0 million and \$0.6 million at March 31, 2007 and December 31, 2006, respectively. We invest available cash balances in various financial instruments, such as tax-exempt debt securities, that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features, which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted.

Restricted investments consist of \$102.0 million in investments in commercial paper and various other high-grade debt securities at both March 31, 2007 and December 31, 2006. These investments are used as collateral to secure the term loan portion of our credit facility and are to be used only for future capital expenditures.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Deposits Deposits consist of an earnest deposit of \$9.0 million paid in March 2007 in conjunction with the agreement to acquire certain gathering and compression assets from Anadarko Petroleum Corporation. This earnest deposit was returned to us at the closing of the transaction in May 2007.

Revenue Recognition We generate the majority of our revenues from: (1) sales of natural gas, propane, NGLs and condensate; (2) natural gas gathering, processing and transportation, from which we generate revenue primarily through the compression, gathering, treating, processing and transportation of natural gas; (3) NGL transportation from which we generate revenues from transportation fees; as well as (4) trading and marketing of natural gas and NGLs.

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

Fee-based arrangements Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing or transporting natural gas; and transporting NGLs. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. 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/index arrangements Under percentage-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percentage-of-proceeds/index arrangements correlate directly with the price of natural gas and/or NGLs.

Propane sales arrangements Under propane sales arrangements, we generally purchase propane from natural gas processing plants and fractionation facilities, and crude oil refineries. We sell propane on a wholesale basis to retail propane distributors, who in turn resell to their retail customers. Our sales of propane are not contingent upon the resale of propane by propane distributors to their retail customers.

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

We generally report revenues gross in the condensed consolidated statements of operations, as we typically act as the principal in these transactions, take custody to the product, and incur the risks and rewards of ownership. Effective April 1, 2006, any new or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction.

3. Recent Accounting Pronouncements

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

SFAS No. 157, Fair Value Measurements, or SFAS 157 In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard also responds to investors' requests for more information

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about: (1) the extent to which companies measure assets and liabilities at fair value; (2) the information used to measure fair value; and (3) the effect that fair value measurements have on earnings. SFAS 157 will apply whenever another standard requires (or permits) assets or liabilities to be measured at fair value. SFAS 157 does not expand the use of fair value to any new circumstances. SFAS 157 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 157 on our consolidated results of operations, cash flows or financial position.

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

4. Acquisition

On November 1, 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC for aggregate consideration of approximately \$82.9 million, which consisted of \$77.3 million in cash (\$9.9 million of which was paid in January 2007), and the issuance of 200,312 Class C units valued at approximately \$5.6 million. Included in the aggregate consideration was \$10.5 million of costs incurred through October 31, 2006, which were associated with the construction of a new propane pipeline terminal.

The transfer of assets between DCP Midstream, LLC and us represents a transfer of assets between entities under common control. Transfers of net assets or exchanges of shares between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method.

The following table presents the impact on our unaudited condensed consolidated statement of operations, adjusted for the acquisition of our wholesale propane logistics business from DCP Midstream, LLC, for the three months ended March 31, 2006 (\$ in millions):

	DCP Midstream Partners, LP	Wholesale Propane Logistics Business	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	\$ 113.5	\$ 145.5	\$ 259.0
Transportation and other	6.5	(0.1)	6.4
Total operating revenues	120.0	145.4	265.4
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	102.1	139.8	241.9
Operating and maintenance expense	4.3	2.1	6.4
Depreciation and amortization expense	3.0	0.3	3.3
General and administrative expense	4.1	0.6	4.7
Total operating costs and expenses	113.5	142.8	256.3

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Operating income	6.5	2.6	9.1
Interest expense, net	(1.1)		(1.1)
Net income	\$ 5.4	\$ 2.6	\$ 8.0

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

DCP Midstream, LLC provided centralized corporate functions on behalf of our predecessor operations, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The predecessor's share of those costs was allocated based on the predecessor's proportionate net investment (consisting of property, plant and equipment, net, equity

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

method investment, and intangible assets, net) as compared to DCP Midstream, LLC's net investment. In management's estimation, the allocation methodologies used were reasonable and resulted in an allocation to the predecessors of their respective costs of doing business, which were borne by DCP Midstream, LLC.

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The Omnibus Agreement: (1) states that the annual fee of \$4.8 million under the agreement is fixed at such amount for 2006, subject to annual increases in the Consumer Price Index, and increases in connection with the expansion of our operations through the acquisition or construction of new assets or businesses, which is \$5.0 million for 2007; and (2) effective November 2006, includes an additional annual fee of \$2.0 million related to the acquisition of our wholesale propane logistics business from DCP Midstream, LLC, subject to the same conditions noted above.

The Omnibus Agreement addresses the following matters:

our obligation to reimburse DCP Midstream, LLC for 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 DCP Midstream, LLC for providing us with general and administrative services with respect to our business and operations, which is \$7.0 million in 2007, subject to an increase for 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 the special committee of the General Partner's board of directors;

our obligation to reimburse DCP Midstream, LLC for insurance coverage expenses it incurs with respect to our business and operations and with respect to director and officer liability coverage;

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

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

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

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

Indemnification

Under the Omnibus Agreement, DCP Midstream, LLC 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. DCP Midstream, LLC's maximum liability for this indemnification obligation does not exceed \$15 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed \$250,000. DCP Midstream, LLC has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Additionally, DCP Midstream, LLC 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 DCP Midstream, LLC for all losses attributable to the postclosing operations of the assets contributed to us, to the extent not subject to DCP Midstream, LLC's indemnification obligations. In addition, DCP Midstream, LLC has agreed to indemnify us for up to \$5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake 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. DCP Midstream, LLC had also agreed to indemnify us for up to \$4.0 million of the costs associated with any repairs to the Seabreeze pipeline that were determined to be necessary as a result of pipeline integrity testing that occurred in 2006. Pipeline integrity testing and repairs were our responsibility and were recognized as operating and maintenance expense. Reimbursement of these expenses from DCP Midstream, LLC were not significant and were recognized by us as capital contributions.

Other Agreements and Transactions with DCP Midstream, LLC

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

DCP Midstream, LLC will supply Pelico's system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. We generally report purchases associated with these activities gross in the condensed consolidated statements of operations as purchases of natural gas, propane and NGLs from affiliates.

If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index-based price, less a contractually agreed-to marketing fee. We generally report revenues associated with these activities gross in the condensed consolidated statements of operations as sales of natural gas, propane and NGLs to affiliates.

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

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

We also have a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze pipeline, pursuant to a fee-based rate that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a 17-year transportation agreement expiring in 2022. We generally report revenues associated with these activities in the condensed consolidated statements of operations as transportation and processing services to affiliates.

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In December 2006, we completed construction of our Wilbreeze pipeline, which connects a DCP Midstream, LLC gas processing plant to our Seabreeze pipeline. The project is supported by a 10-year NGL product dedication agreement with DCP Midstream, LLC. We generally report revenues, which are earned pursuant to a fee-based rate applied to the volumes transported on this pipeline, in the condensed consolidated statements of operations as transportation and processing services to affiliates.

Table of Contents**DCP MIDSTREAM PARTNERS, LP****NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Unaudited)**

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

DCP Midstream, LLC was a significant customer during the three months ended March 31, 2007 and 2006.

Duke Energy and Spectra Energy

Prior to December 31, 2006, we charged transportation fees, sold a portion of our residue gas to, and purchased raw natural gas from, Duke Energy Corporation, or Duke Energy, and its affiliates. Effective January 1, 2007, we charge transportation fees, sell a portion of our residue gas to, and purchase raw natural gas from, Spectra Energy, the natural gas business that was spun off from Duke Energy in January 2007, and its affiliates. We anticipate continuing to purchase and sell these commodities to Spectra Energy and its affiliates in the ordinary course of business.

ConocoPhillips

We have multiple agreements whereby we provide a variety of services to ConocoPhillips and its affiliates. The agreements include fee-based and percentage-of-proceeds gathering and processing arrangements, gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received \$1.2 million and \$0 million of capital reimbursements during the three months ended March 31, 2007 and 2006, respectively.

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

	Three Months Ended March 31,	
	2007	2006
DCP Midstream, LLC:		
Sales of natural gas, propane, NGLs and condensate	\$ 54.6	\$ 74.9
Transportation and processing services	\$ 1.6	\$ 1.2
Purchases of natural gas, propane and NGLs	\$ 40.0	\$ 27.9
Losses from non-trading derivative activity	\$ (0.1)	\$ (0.1)
General and administrative expense	\$ 2.3	\$ 1.9
Duke Energy:		
Purchases of natural gas, propane and NGLs	\$	\$ 0.2
ConocoPhillips:		
Transportation and processing services	\$ 2.4	\$ 1.5
Purchases of natural gas, propane and NGLs	\$ 7.8	\$ 3.3

We had accounts receivable and accounts payable with affiliates as follows (\$ in millions):

	March 31,	December 31,
	2007	2006
DCP Midstream, LLC:		
Accounts receivable	\$ 23.5	\$ 30.0
Accounts payable	\$ 19.6	\$ 46.6

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Spectra Energy:			
Accounts receivable	\$	0.2	\$
Duke Energy:			
Accounts receivable	\$		\$ 0.2
Accounts payable	\$		\$ 1.8
ConocoPhillips:			
Accounts receivable	\$	4.3	\$ 4.6
Accounts payable	\$	1.1	\$ 2.0

Table of Contents**DCP MIDSTREAM PARTNERS, LP****NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Unaudited)****6. Debt**

We have a 5-year credit agreement, or the Credit Agreement, with a \$250.0 million revolving credit facility and a \$100.1 million term loan facility. The Credit Agreement matures on December 7, 2010. The term loan facility is fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying condensed consolidated balance sheets. The unused portion of the revolving credit facility may be used for letters of credit. At both March 31, 2007 and December 31, 2006 there were outstanding letters of credit of \$0.2 million.

Long-term debt was as follows (\$ in millions):

	Principal Amount	
	March 31, 2007	December 31, 2006
Revolving credit facility, weighed-average interest rate of 5.85% at March 31, 2007, due December 7, 2010	\$ 168.0	\$ 168.0
Term loan facility, interest rate of 5.47% at March 31, 2007, due December 7, 2010	100.0	100.0
Total long-term debt	\$ 268.0	\$ 268.0

7. Partnership Equity and Distributions

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

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

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

provide for the proper conduct of our business;

comply with applicable law, any of our debt instruments or other agreements; or

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

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

General Partner Interest and Incentive Distribution Rights The general partner is entitled to 2% of all quarterly distributions that we make prior to our liquidation. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions will be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 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. The general partner's incentive distribution rights are not reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Please read the *Distributions of Available Cash during the Subordination Period* and *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Class C Units The Class C units have the same liquidation preference, rights to cash distributions and voting rights as the common units. The Class C units will automatically convert to common units once the Class C units represent less than 1% of the total outstanding limited partner units, or LPUs. After two years, if the Class C units are not converted into common units, either automatically or by common unitholder approval, they will receive 115% of the distribution amount for common units.

Subordinated Units All of the subordinated units are held by DCP Midstream, LLC. Our partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to \$0.35 per common unit, or the Minimum Quarterly Distribution, plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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.

Treasury Units In March 2007, we purchased 4,000 units on the open market, at an average cost of \$39.16 per unit. These units were held as treasury units at March 31, 2007, and will be used for director compensation pursuant to the DCP Midstream Partners, LP Long-Term Incentive Plan, or LTIP.

Distributions of Available Cash during the Subordination Period The partnership agreement requires that we make 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 we distribute 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 we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;

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

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 (the First Target Distribution);

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 (the Second Target Distribution);

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 (the Third Target Distribution); and

thereafter, 50% to all unitholders, pro rata, and 50% to the general partner (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period Our partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

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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;

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.

In February 2006, we paid a cash distribution of \$0.095 per unit, to unitholders of record on February 3, 2006. That distribution represented the pro rata portion of our Minimum Quarterly Distribution of \$0.35 per unit for the period December 7, 2005, the closing of our initial public offering, through December 31, 2005. In February 2007, we paid a cash distribution of \$0.43 per unit, to unitholders of record on February 7, 2007.

Table of Contents**DCP MIDSTREAM PARTNERS, LP****NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Unaudited)****8. Risk Management and Hedging Activities**

Commodity Cash Flow Hedges We use 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 condensed consolidated statements of operations as sales of natural gas, propane, NGLs and condensate. For the three months ended March 31, 2007 and 2006, we recognized losses of \$0 million and \$0.4 million, respectively, due to the ineffectiveness of these cash flow hedges. For the three months ended March 31, 2007 and 2006, net gains of \$1.3 million and net losses of \$0.2 million were reclassified into earnings as a result of settlements. For the three months ended March 31, 2007 and 2006, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring, 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 impacts earnings, amounts in AOCI associated with the hedged transaction will be reclassified to the condensed consolidated statements of operations in the same accounts as the item being hedged. As of March 31, 2007 and December 31, 2006, there were net deferred gains of \$0.8 million and \$6.9 million, respectively, related to commodity cash flow hedge derivative contracts in AOCI. As of March 31, 2007, \$0.3 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings; however, due to the volatility of the commodities markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings.

Commodity Fair Value Hedges We use 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. We may hedge producer price locks (fixed price gas purchases) to reduce our exposure to fixed price risk by swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index-based).

For the three months ended March 31, 2007 and 2006 the gains or losses representing the ineffective portion of our fair value hedges were not significant. All components of each derivative's gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted. During the three months ended March 31, 2007 and 2006, there were no firm commitments that no longer qualified as fair value hedge items and, therefore, we did not recognize an associated gain or loss.

Commodity Non-Trading Derivative Activity Our operations of gathering, processing, and transporting natural gas, and the accompanying operations of transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. We occasionally will enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings. We manage our asset-based activities in accordance with our Risk Management Policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

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For the three months ended March 31, 2007 and 2006, we recognized \$0.1 million as losses from non-trading derivative activity affiliates in both periods on this activity.

Interest Rate Cash Flow Hedges During 2006, we entered into interest rate swap agreements to hedge the variable interest rate on \$125.0 million of the indebtedness outstanding under our revolving credit facility. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation.

Table of Contents**DCP MIDSTREAM PARTNERS, LP****NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Unaudited)**

The effective portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheets. For the three months ended March 31, 2007 and 2006, gains of \$0.1 million and \$0 million, respectively were reclassified into earnings as a result of settlements. As of March 31, 2007 and December 31, 2006, losses of \$0.2 million and gains of \$0.4 million, respectively, were deferred in AOCI related to these swaps. As of March 31, 2007, \$0.3 million of deferred net gains on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings; however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings.

Ineffective portions of changes in fair value are recognized in earnings. The agreements repriced prospectively approximately every 90 days, and expire on December 7, 2010. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 4.68% to 5.08%, and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

9. Equity-Based Compensation

On November 28, 2005, the board of directors of the General Partner adopted the LTIP for employees, consultants and directors of the General Partner and its affiliates who perform services for us, effective as of December 7, 2005. Under the LTIP, equity-based instruments may be granted to our key employees. The LTIP provides for the grant of LPUs, 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 LPUs may be delivered pursuant to awards under the LTIP. Awards that are canceled, forfeited or are withheld to satisfy the General Partner's tax withholding obligations are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the General Partner's board of directors. We first granted awards under the LTIP during 2006.

Performance Units We have awarded phantom LPUs pursuant to the LTIP, or Performance Units, to certain employees. Performance Units generally vest in their entirety at the end of a three year performance period. The number of Performance Units which will ultimately vest range from 0% to 150% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year performance periods. The final performance payout is determined by the compensation committee of the board of directors of the General Partner. Each Performance Unit includes a DER, which will be paid in cash at the end of the performance period.

We recorded approximately \$0.1 million and \$0 million of compensation expense related to the Performance Units during the three months ended March 31, 2007 and 2006, respectively. At March 31, 2007, there was approximately \$1.7 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 2.3 years. The following table presents information related to the Performance Units:

		Grant Date	Measurement	
		Weighted-	Date Price	
	Units	Average Price	per Unit	
		per Unit	per Unit	
Outstanding at December 31, 2006	23,090	\$ 26.96		
Granted	29,610	\$ 37.23		
Outstanding at March 31, 2007	52,700	\$ 32.73	\$	39.10

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Expected to vest

52,700 \$ 32.73 \$ 39.10

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our condensed consolidated statements of operations.

IPO Phantom Units In conjunction with our initial public offering, in January 2006 the General Partner's board of directors awarded phantom LPUs, or IPO Phantom Units, to key employees, and to directors who are not officers or employees of affiliates of the General Partner. Of these IPO Phantom Units, 16,700 units will vest upon the three year anniversary of the grant date, and 5,332 units vest ratably over two years. Each IPO Phantom Unit includes a DER, which is paid quarterly in arrears.

Table of Contents**DCP MIDSTREAM PARTNERS, LP****NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Unaudited)**

We recorded approximately \$0.1 million of compensation expense related to the IPO Phantom Units during the each of the three months ended March 31, 2007 and 2006. At March 31, 2007, there was approximately \$0.5 million of unrecognized compensation expense related to the IPO Phantom Units that is expected to be recognized over a weighted-average period of 1.5 years. The following table presents information related to the IPO Phantom Units:

	Units	Grant Date Weighted- Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2006	24,700	\$ 24.05	
Vested or paid in cash	(2,668)	\$ 24.05	
Outstanding at March 31, 2007	22,032	\$ 24.05	\$ 39.10
Expected to vest	22,032	\$ 24.05	\$ 39.10

The estimate of IPO Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our condensed consolidated statements of operations.

We intend to settle the awards issued under the LTIP in cash upon vesting. Compensation expense is recognized ratably over each vesting period, and will be remeasured quarterly for all awards outstanding until the units are vested. The fair value of all awards is determined based on the closing price of our common units at each measurement date. During the three months ended March 31, 2007, 2,668 awards vested and were settled in cash for \$0.1 million. No awards were vested or settled during the three months ended March 31, 2006.

10. Net Income per Limited Partner Unit

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

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

These required disclosures do not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds the First Target Distribution Level, it will have the impact of reducing net income per LPU. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of Available Cash and not earnings. In periods in which our aggregate net income does not exceed the First Target Distribution Level, there is no impact on our calculation of earnings per LPU. During the quarter ended March 31, 2007, our aggregate net income per LPU exceeded the Third Target Distribution level, and as a result we allocated \$1.9 million in additional earnings to the general partner. During the quarter ended March 31, 2006, our aggregate net income per LPU was less than the First Target Distribution level, and there was no impact on our calculation of earnings per LPU.

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Basic and diluted net income per LPU is calculated by dividing limited partners' interest in net income, less pro forma general partner incentive distributions as described above, by the weighted-average number of outstanding LPUs during the period.

Table of Contents**DCP MIDSTREAM PARTNERS, LP****NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Unaudited)**

The following table illustrates our calculation of net income per LPU (\$ in millions):

	Three Months Ended March 31,	
	2007	2006
Net income	\$ 12.5	\$ 8.0
Less:		
Net income attributable to predecessor operations		(2.6)
Net income attributable to the partnership	12.5	5.4
Less: General partner interest in net income	(0.3)	(0.1)
Limited partners' interest in net income	12.2	5.3
Less: Additional earnings allocation to general partner	(1.9)	
Net income available to limited partners	\$ 10.3	\$ 5.3
Net income per LPU - basic and diluted	\$ 0.58	\$ 0.30

11. Commitments and Contingent Liabilities*Litigation*

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

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

Indemnification DCP Midstream, LLC has indemnified 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 of our initial public offering. See the Indemnification section of Note 5 for additional details.

Table of Contents**DCP MIDSTREAM PARTNERS, LP****NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Unaudited)****12. Business Segments**

Our operations are located in the United States and are organized into three reporting segments: (1) Natural Gas Services; (2) Wholesale Propane Logistics; and (3) NGL Logistics.

Natural Gas Services The Natural Gas Services segment consists of 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.

Wholesale Propane Logistics The Wholesale Propane Logistics segment consists of six owned propane rail terminals located in the Midwest and northeastern United States, one leased propane marine terminal located in Providence, Rhode Island, one propane terminal pipeline under construction in Midland, Pennsylvania and access to several open access pipeline terminals.

NGL Logistics The NGL Logistics segment consists of the Seabreeze and Wilbreeze NGL transportation pipelines, which are located along the Gulf Coast area of southeastern Texas, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline located in northern Louisiana and southeastern Texas. The Wilbreeze transportation pipeline was not operational until December 2006.

These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment. The following tables set forth our segment information (\$ in millions):

Three Months Ended March 31, 2007

	Natural Gas	Wholesale Propane Logistics	NGL	Other(b)	Total
	Services		Logistics		
Total operating revenue	\$ 86.4	\$ 151.8	\$ 1.9	\$	\$ 240.1
Gross margin (a)	\$ 17.1	\$ 10.8	\$ 1.3	\$	\$ 29.2
Operating and maintenance expense	(3.3)	(3.2)	(0.1)		(6.6)
Depreciation and amortization expense	(2.9)	(0.2)	(0.3)		(3.4)
General and administrative expense				(4.8)	(4.8)
Earnings from equity method investments			0.2		0.2
Interest income				1.7	1.7
Interest expense				(3.8)	(3.8)
Net income (loss)	\$ 10.9	\$ 7.4	\$ 1.1	\$ (6.9)	\$ 12.5
Capital expenditures	\$ 1.8	\$ 1.2	\$ 0.4	\$	\$ 3.4

Three Months Ended March 31, 2006

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	Natural Gas	Wholesale Propane	NGL		
	Services	Logistics	Logistics	Other(b)	Total
Total operating revenues	\$ 118.8	\$ 145.4	\$ 1.2	\$	\$ 265.4
Gross margin (a)	\$ 17.0	\$ 5.6	\$ 0.9	\$	\$ 23.5
Operating and maintenance expense	(4.1)	(2.1)	(0.2)	\$	(6.4)
Depreciation and amortization expense	(2.8)	(0.3)	(0.2)	\$	(3.3)
General and administrative expense	\$	\$	\$	(4.7)	(4.7)
Interest income	\$	\$	\$	1.5	1.5
Interest expense	\$	\$	\$	(2.6)	(2.6)
Net income (loss)	\$ 10.1	\$ 3.2	\$ 0.5	\$ (5.8)	\$ 8.0
Capital expenditures	\$ 3.5	\$ 1.2	\$	\$	\$ 4.7

Table of Contents**DCP MIDSTREAM PARTNERS, LP****NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Unaudited)**

The following table sets forth our total assets segment information (\$ in millions):

	March 31, 2007	December 31, 2006
Segment non-current assets:		
Natural Gas Services	\$ 145.8	\$ 147.4
Wholesale Propane Logistics	51.0	50.2
NGL Logistics	35.2	35.1
Other (c)	106.8	109.3
Total non-current assets	338.8	342.0
Current assets	140.6	159.6
Total assets	\$ 479.4	\$ 501.6

- (a) Gross margin consists of total operating revenues less purchases of natural gas, propane and NGLs. Gross margin is viewed as a non-GAAP measure under the rules of the SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.
- (b) Other consists of general and administrative expense, interest income and interest expense.
- (c) Other non-current assets not allocable to segments consist of restricted investments, unrealized gains on non-trading derivative and hedging instruments, and other non-current assets.

13. Subsequent Events

On April 25, 2007, the board of directors of the General Partner declared a quarterly distribution of \$0.465 per unit, payable on May 15, 2007 to unitholders of record on May 8, 2007.

In April 2007, we acquired certain gathering and compression assets located in northern Louisiana for approximately \$10.2 million. This acquisition was financed via the redemption of existing securities held as restricted investments.

In April 2007, we filed with the SEC a universal shelf registration statement on Form S-3 with a maximum aggregate offering price of \$1.5 billion, which will, upon effectiveness, allow us to register and issue additional partnership units and debt obligations.

In April 2007, there was a fire at our Minden facility, which partially curtailed operations for seven days. Repairs to this facility are not expected to be significant.

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provides for borrowings up to \$100.0 million, and has terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed \$100.0 million, which shall be due and payable no later than August 9, 2007. Our consolidated leverage ratio, currently under the Credit Facility, was also amended to allow for a maximum ratio of 5.75 to 1.0 for the quarter ended June 30, 2007.

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In May 2007, we acquired certain gathering and compression assets located in southern Oklahoma from Anadarko Petroleum Corporation, or Anadarko, for approximately \$181.1 million, subject to customary purchase price adjustments. In conjunction with this transaction, we used borrowings of approximately \$89.0 million from our revolving credit facility to extinguish our term loan facility. As a result of the extinguishment of our term loan facility, we liquidated \$90.8 million of restricted investments, which, in addition to borrowings of \$88.0 million from the Bridge Loan, and \$2.3 million of other liquid investments, were used to fund the acquisition. In conjunction with the acquisition, our earnest deposit of \$9.0 million, paid when we entered into this agreement, was returned to us, and was used to retire indebtedness under our revolving credit facility.

In May 2007, we executed a series of financial transactions to mitigate a significant portion of the commodity price exposure associated with the assets acquired from Anadarko. We entered into natural gas and crude oil swap contracts for a term of June 2007 through December 2013.

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Item 2. 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 condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and the consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2006, or 2006 Form 10-K.

Overview

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

our Natural Gas Services segment, which consists of our North Louisiana natural gas gathering, processing and transportation system;

our Wholesale Propane Logistics segment, which consists of six owned rail terminals, one leased marine terminal, one propane pipeline terminal, which is under construction, and access to several open access pipeline terminals; and

our NGL Logistics segment, which consists of our interests in three NGL pipelines.

The financial information contained herein includes our accounts, and the assets, liabilities and operations of our wholesale propane logistics business, which we acquired in November 2006 from DCP Midstream, LLC in a transaction among entities under common control, for each period presented.

Recent Events

On April 25, 2007, the board of directors of the General Partner declared a quarterly distribution of \$0.465 per unit, payable on May 15, 2007 to unitholders of record on May 8, 2007.

In April 2007, we acquired certain gathering and compression assets located in northern Louisiana for approximately \$10.2 million. This acquisition was financed via the redemption of existing securities held as restricted investments.

In April 2007, we filed with the Securities and Exchange Commission a universal shelf registration statement on Form S-3 with a maximum aggregate offering price of \$1.5 billion, which will upon effectiveness allow us to register and issue additional partnership units and debt obligations.

In April 2007, there was a fire at our Minden facility, which partially curtailed operations for seven days. Repairs to this facility are not expected to be significant.

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provides for borrowings up to \$100.0 million, and has terms and conditions substantially similar to those of our 5-year credit agreement, or the Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed \$100.0 million, which shall be due and payable no later than August 9, 2007. Our consolidated leverage ratio, currently under the Credit Facility, was also amended to allow for a maximum ratio of 5.75 to 1.0 for the quarter ended June 30, 2007.

In May 2007, we acquired certain gathering and compression assets located in southern Oklahoma from Anadarko Petroleum Corporation, or Anadarko, for approximately \$181.1 million, subject to customary purchase price adjustments. In conjunction with this transaction, we used borrowings of approximately \$89.0 million from our revolving credit facility to extinguish our term loan facility. As a result of the extinguishment of our term loan facility, we liquidated \$90.8 million of restricted investments, which, in addition to borrowings of \$88.0 million from the Bridge Loan, and \$2.3 million of other liquid investments, were used to fund the acquisition. In conjunction with the acquisition, our earnest deposit of \$9.0 million, paid when we entered into this agreement, was returned to us, and was used to retire indebtedness under our revolving credit facility.

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In May 2007, we executed a series of financial transactions to mitigate a significant portion of the commodity price exposure associated with the assets acquired from Anadarko. We entered into natural gas and crude oil swap contracts for a term of June 2007 through December 2013.

In October 2006, we announced that DCP Midstream, LLC had committed to contribute assets to us in exchange for partnership units and cash valued at approximately \$250.0 million. The transaction is targeted to close in the second quarter of 2007.

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Identification of the specific assets and the related purchase price, along with the other terms of any specific transaction between DCP Midstream, LLC and us, are subject to the approval of the boards of directors of both us and DCP Midstream, LLC, as well as the special committee of the board of directors of DCP Midstream GP, LLC, or the General Partner.

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, we have hedged a significant portion of our anticipated commodity price risk associated with our gathering and processing arrangements through 2010 with natural gas and crude oil swaps, and a significant portion of our anticipated condensate price risk through 2011 with 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. We will continue to have direct commodity price risk associated with the unhedged portion of our natural gas supply, and production of NGLs and condensate from our processing plants. To the extent we are unable to obtain, or choose not to seek, hedge accounting in conjunction with any future acquisitions as a result of the type of commodity risk assumed, or structure of such acquisition, our earnings and cash flows could be subject to increased volatility. For additional information regarding our hedging activities, please read **Quantitative and Qualitative Disclosures about Market Risk** **Commodity Price Risk** **Hedging Strategies** in our 2006 Form 10-K. 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 December 2006, the Pelico system filed a new Section 311 rate case with the Federal Energy Regulatory Commission. The settlement in the rate case, which was approved on April 25, 2007, provided for an increase in the maximum transportation rate that the Pelico system can charge, to \$0.2322 per MMBtu from \$0.1965 per MMBtu, effective December 1, 2006. There were no other changes to the Pelico system's terms and conditions of service.

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

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

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

In November 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC in a transaction among entities under common control. Accordingly, our financial information includes the historical results of our wholesale propane logistics business for each period presented. Prior to November 2006, our financial statements do not give effect to various items that affected our results of operations and liquidity following the acquisition of our wholesale propane logistics business, including the indebtedness we incurred in conjunction with the closing of the acquisition of our wholesale propane logistics business, which increased our interest expense from the interest expense reflected in our historical financial statements.

We completed pipeline integrity testing during 2006, resulting in increased operating costs on Seabreeze, one of our NGL transportation pipelines. The construction of Wilbreeze, an NGL transportation pipeline connecting a DCP Midstream, LLC gas processing plant to the Seabreeze pipeline, was completed in December 2006. The Black Lake pipeline is currently experiencing increased operating costs due to pipeline integrity testing that commenced in 2005 and has continued into 2007. We expect that our results of operations related to our equity interest in the Black Lake pipeline will benefit in 2007 from the completion of this pipeline integrity testing, although it is possible that the

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integrity testing will result in the need for pipeline repairs, in which case the operations of this pipeline may be interrupted while the repairs are being made. DCP Midstream, LLC has agreed to indemnify us for up to \$5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing, 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

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testing. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Any reimbursement of these expenses from DCP Midstream, LLC will be recognized by us as a capital contribution. Seabreeze pipeline integrity testing was completed in 2006 and reimbursements related to these repairs were not significant.

During 2006, we entered into agreements with ConocoPhillips, which expanded the gathering and transportation services between us. As a result of these agreements, 5 new wells were added during the three months ended March 31, 2007, and 17 new wells were added to our system during 2006, with additional volumes possible over the next three years.

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

Our Operations

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

Natural Gas Services Segment

Results of operations from our Natural Gas Services segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our gathering, processing and pipeline systems; the volumes of NGLs and condensate sold; and the level of our realized natural gas, NGL and condensate prices. We generate our revenues and our gross margin for our Natural Gas Services segment principally under fee-based arrangements and percentage-of-proceeds arrangements, as described in *Critical Accounting Policies and Estimates Revenue Recognition* in our 2006 Form 10-K.

We have hedged a significant portion 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. We have hedged a significant portion of our condensate price risk through 2011 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* in our 2006 Form 10-K.

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 cost 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 represented approximately 63% of the 305 MMcf/d of natural gas supplied to this system in the first quarter of 2007. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been released from other gathering systems.

We sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, 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 DCP Midstream, LLC as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties. We also have entered into a contractual arrangement with DCP Midstream, LLC that provides

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that DCP Midstream, LLC will purchase natural gas and transport it into our Pelico system, where we will buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. 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 DCP Midstream, LLC that provides that DCP Midstream, LLC 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 DCP Midstream, LLC 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 affiliates.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the Midwest and Northeast United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Midwest and the northeastern areas of the United States. Our primary suppliers of propane represented approximately 45% of our propane purchases in the first quarter of 2007. We sell propane on a wholesale basis to retail propane distributors who in turn resell propane to their retail customers.

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

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

NGL Logistics Segment

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

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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 not accounting principles generally accepted in the United States of America, or GAAP, financial measures. We provide reconciliations of these non-GAAP measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. Our gross margin, segment gross margin, EBITDA and distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

Volumes We view throughput volumes on our North Louisiana system and our NGL pipelines, and sales volumes in our wholesale propane business as important factors affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of 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 pipelines are substantially dependent upon the quantities of NGLs produced at our processing plants, as well as NGLs produced at other processing plants that have pipeline connections with the NGL pipelines. We regularly monitor producer activity in the areas served by the North Louisiana system and our pipelines, and pursue opportunities to connect new supply to these pipelines.

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

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

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 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.

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

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Reconciliation of Non-GAAP Measures	Three Months Ended March 31,	
	2007	2006
Reconciliation of net income to gross margin:		
Net income	\$ 12.5	\$ 8.0
Add:		
Interest expense	3.8	2.6
Operating and maintenance expense	6.6	6.4
Depreciation and amortization expense	3.4	3.3
General and administrative expense	4.8	4.7
Less:		
Interest income	(1.7)	(1.5)
Earnings from equity method investments	(0.2)	
Gross margin	\$ 29.2	\$ 23.5
Reconciliation of segment net income to segment gross margin:		
Natural Gas Services segment:		
Segment net income	\$ 10.9	\$ 10.1
Add:		
Depreciation and amortization expense	2.9	2.8
Operating and maintenance expense	3.3	4.1
Segment gross margin	\$ 17.1	\$ 17.0
Wholesale Propane Logistics segment:		
Segment net income	\$ 7.4	\$ 3.2
Add:		
Depreciation and amortization expense	0.2	0.3
Operating and maintenance expense	3.2	2.1
Segment gross margin	\$ 10.8	\$ 5.6
NGL Logistics segment:		
Segment net income	\$ 1.1	\$ 0.5
Add:		
Depreciation and amortization expense	0.3	0.2
Operating and maintenance expense	0.1	0.2
Less: Earnings from equity method investments	(0.2)	
Segment gross margin	\$ 1.3	\$ 0.9

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

A substantial amount of our general and administrative expense is incurred through DCP Midstream, LLC. For the three months ended March 31, 2007 and 2006, our general and administrative expense was \$4.8 million and \$4.7 million, respectively. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The Omnibus Agreement: (1) states that the annual fee of \$4.8 million under the agreement is fixed at such amount for 2006, subject to annual increases in the Consumer Price Index, and increases in connection with the expansion of our

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operations through the acquisition or construction of new assets or businesses, which is \$5.0 million for 2007; and (2) effective November 2006, includes an additional annual fee of \$2.0 million related to the acquisition of our wholesale propane logistics business from DCP Midstream, LLC, subject to the same conditions noted above.

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We incurred approximately \$3.1 million and \$3.5 million of other general and administrative expense during the quarters ended March 31, 2007 and 2006, respectively, primarily relating to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation. These incremental expenses exclude \$1.7 million and \$1.2 million for the quarters ended March 31, 2007 and 2006, respectively, per the Omnibus Agreement, as amended, for other various general and administrative services.

EBITDA and Distributable Cash Flow We define EBITDA as net income less interest income, plus 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 5-year credit agreement, or 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; 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

viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

We define distributable cash flow as EBITDA, plus interest income, less interest expense, maintenance capital expenditures, net of reimbursable projects, undistributed earnings from equity method investments, adjustments for non-cash hedge ineffectiveness and non-cash derivative mark to market gains and losses (see [Liquidity and Capital Resources](#) below for further definition of maintenance capital expenditures). In 2006, we also adjusted distributable cash flow for a post-closing reimbursement from DCP Midstream, LLC for maintenance capital expenditures. Maintenance capital expenditures are capital expenditures made where we add on to or improve capital assets owned, or acquire or construct new capital assets, if such expenditures are made to maintain, including over the long term, our operating capacity or revenues. Non-cash hedge ineffectiveness refers to the ineffective portion of our cash flow hedges, which is recorded in earnings in the current period. This amount is considered to be non-cash for the purpose of computing distributable cash flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices. Distributable cash flow is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner. Our distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate distributable cash flow in the same manner. The following table sets forth our reconciliation of certain non-GAAP measures (\$ in millions):

Reconciliation of Non-GAAP Measures	Three Months Ended March 31,	
	2007	2006
Reconciliation of net income to EBITDA:		
Net income	\$ 12.5	\$ 8.0
Interest income	(1.7)	(1.5)
Interest expense	3.8	2.6
Depreciation and amortization expense	3.4	3.3
EBITDA	\$ 18.0	\$ 12.4
Reconciliation of net cash provided by operating activities to EBITDA:		
Net cash provided by operating activities	\$ 14.2	\$ 8.2
Interest income	(1.7)	(1.5)
Interest expense	3.8	2.6
Undistributed earnings from equity method investments	0.2	
Net changes in operating assets and liabilities	1.0	2.4
Other, net	0.5	0.7
EBITDA	\$ 18.0	\$ 12.4

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2006 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three months ended March 31, 2007 are the same as those described in our 2006 Form 10-K.

Table of Contents**Results of Operations***Consolidated Overview*

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2007 and 2006. The results of operations by segment are discussed in further detail following this consolidated overview discussion (\$ in millions, except operating data):

	Three Months Ended March 31,	
	2007	2006
Operating revenues:		
Natural Gas Services	\$ 86.4	\$ 118.8
Wholesale Propane Logistics	151.8	145.4
NGL Logistics	1.9	1.2
Total operating revenues	240.1	265.4
Gross margin (a):		
Natural Gas Services	17.1	17.0
Wholesale Propane Logistics	10.8	5.6
NGL Logistics	1.3	0.9
Total gross margin	29.2	23.5
Operating and maintenance expense	6.6	6.4
General and administrative expense	4.8	4.7
Earnings from equity method investments (b)	(0.2)	
EBITDA (c)	18.0	12.4
Depreciation and amortization expense	3.4	3.3
Interest income	(1.7)	(1.5)
Interest expense	3.8	2.6
Net income	\$ 12.5	\$ 8.0
Operating data:		
Natural gas throughput (MMcf/d)	371	364
NGL gross production (Bbls/d)	5,304	4,962
Propane sales volume (Bbls/d)	35,358	34,599
NGL pipelines throughput (Bbls/d) (b)	27,458	23,425

- (a) Gross margin consists of total operating revenues less purchases of natural gas, propane and NGLs, and segment gross margin for each segment consists of total operating revenues for that segment, less commodity purchases for that segment. Please read *How We Evaluate Our Operations* above.
- (b) Includes 45% of the throughput volumes and earnings of Black Lake.
- (c) EBITDA consists of net income less interest income plus interest expense, and depreciation and amortization expense. Please read *How We Evaluate Our Operations* above.

Three Months Ended March 31, 2007 vs. Three Months Ended March 31, 2006

Total Operating Revenues Total operating revenues decreased \$25.3 million, or 10%, to \$240.1 million in 2007 from \$265.4 million in 2006, primarily due to the following:

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\$34.8 million decrease attributable primarily to a decrease in natural gas sales volumes, an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation and lower natural gas prices for our Natural Gas Services segment; offset by

\$6.6 million increase attributable to higher propane prices and sales volumes for our Wholesale Propane Logistics segment;

\$1.7 million increase related to commodity hedging and non-trading derivative activity;

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\$0.8 million increase in transportation and processing services revenue primarily attributable to an increase in volumes; and

\$0.4 million increase due to an increase in NGL sales as well as the composition of inventory transactions at receipt versus delivery points for our NGL Logistics segment.

Gross Margin Gross margin increased \$5.7 million, or 24%, to \$29.2 million in 2007 from \$23.5 million in 2006, primarily due to the following:

\$5.2 million increase due to higher per unit margins as a result of changes in contract mix, our ability to utilize various supply sources, non-cash lower of cost or market inventory adjustments, and higher sales volumes for our Wholesale Propane Logistics segment;

\$0.4 million increase attributable to increased transportation revenue and volumes for our NGL Logistics segment as a result of the addition of our Wilbreeze pipeline in 2007, which was placed in service in December 2006; and

\$0.1 million increase for our Natural Gas Services segment primarily due to increases related to commodity hedging and non-trading derivative activity, higher NGL and condensate production, and higher natural gas throughput volumes. These increases were offset by a decrease attributable primarily to a decrease in marketing margins from the decline in the differences in natural gas prices at various receipt and delivery points across our Pelico system and lower natural gas prices.

Operating and Maintenance Expense Operating and maintenance expense increased \$0.2 million, or 3%, to \$6.6 million in 2007 from \$6.4 million in 2006, primarily as a result of higher operating and maintenance expense at the new Midland terminal, which is scheduled to become operational in the second quarter of 2007, and higher labor and benefit costs in our Wholesale Propane Logistics segment, partially offset by lower pipeline integrity and repairs and maintenance costs in our Natural Gas Services segment.

General and Administrative Expense General and administrative expense remained relatively constant in 2007 and 2006.

Earnings from Equity Method Investments Earnings from equity method investments increased to \$0.2 million in 2007 from \$0 in 2006. This increase was as a result of higher sales volumes and reduced operating expenses on our Black Lake pipeline.

Depreciation and Amortization Expense Depreciation and amortization expense was relatively constant in 2007 and 2006.

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 (\$ in millions, except operating data):

	Three Months Ended March 31,	
	2007	2006
Operating revenues:		
Sales of natural gas, NGLs and condensate	\$ 80.2	\$ 113.3
Transportation and processing services	6.0	5.5
Gains from non-trading derivative activity	0.2	
Total operating revenues	86.4	118.8
Purchases of natural gas and NGLs	69.3	101.8
Segment gross margin (a)	17.1	17.0
Operating and maintenance expense	3.3	4.1

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Depreciation and amortization expense	2.9	2.8
Segment net income	\$ 10.9	\$ 10.1
Operating data:		
Natural gas throughput (MMcf/d)	371	364
NGL gross production (Bbls/d)	5,304	4,962

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

Three Months Ended March 31, 2007 vs. Three Months Ended March 31, 2006

Total Operating Revenues Total operating revenues decreased \$32.4 million, or 27%, to \$86.4 million in 2007 from \$118.8 million in 2006, primarily due to the following:

\$19.3 million decrease attributable to a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation;

\$17.0 million decrease attributable to a decrease in commodity prices; offset by

\$1.9 million increase related to commodity hedging and non-trading derivative activity;

\$1.5 million increase primarily attributable to higher NGL and condensate sales volumes;

\$0.5 million increase in transportation and processing services revenue primarily attributable to an increase in natural gas throughput.
Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased \$32.5 million, or 32%, to \$69.3 million in 2007 from \$101.8 million in 2006, primarily due to decreased natural gas purchase volumes and lower costs of raw natural gas supply, driven by lower natural gas prices, and an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation,

Segment Gross Margin Segment gross margin increased \$0.1 million, or 1%, to \$17.1 million in 2007 from \$17.0 million in 2006, primarily as a result of the following:

\$1.9 million increase related to commodity hedging and non-trading derivative activity; and

\$1.7 million increase primarily attributable to an increase in NGL and condensate production, and an increase in natural gas throughput volumes; offset by

\$2.5 million decrease attributable primarily to a decrease in marketing margins from the decline in the differences in natural gas prices at various receipt and delivery points across our Pelico system, which were atypically high in 2006, partially offset by an increase in marketing activity and throughput across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur;

\$0.9 million decrease primarily attributable to lower natural gas prices, partially offset by favorable frac spreads. The favorable frac spreads may not continue in the future; and

\$0.1 million decrease primarily attributable to a change in contract mix.

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Operating and Maintenance Expense Operating and maintenance expense decreased \$0.8 million, or 20%, to \$3.3 million in 2007 from \$4.1 million in 2006, primarily as a result of lower pipeline integrity and repair and maintenance costs.

NGL production during 2007 increased 342 Bbls/d, or 7%, to 5,304 Bbls/d from 4,962 Bbls/d in 2006, due primarily to an increase of gas volumes at our Minden processing plant in 2007. Natural gas transported and/or processed during 2007 increased 7 MMcf/d, or 2%, to 371 MMcf/d from 364 MMcf/d in 2006, primarily as a result of higher natural gas volumes.

Table of Contents**Results of Operations Wholesale Propane Logistics Segment**

This segment includes our propane transportation facilities, which includes six owned propane rail terminals, one leased propane marine terminal, one propane pipeline terminal, which is under construction, and access to several open access propane pipeline terminals (\$ in millions, except operating data):

	Three Months Ended March 31,	
	2007	2006
Operating revenues:		
Sales of propane	\$ 152.1	\$ 145.5
Losses from non-trading derivative activity	(0.3)	(0.1)
Total operating revenues	151.8	145.4
Purchases of propane	141.0	139.8
Segment gross margin (a)	10.8	5.6
Operating and maintenance expense	3.2	2.1
Depreciation and amortization expense	0.2	0.3
Segment net income	\$ 7.4	\$ 3.2
Operating data:		
Propane sales volume (Bbls/d)	35,358	34,599

(a) Segment gross margin consists of total operating revenues less purchases of propane. Please read *How We Evaluate Our Operations* above. **Three Months Ended March 31, 2007 vs. Three Months Ended March 31, 2006**

Total Operating Revenues Total operating revenues increased \$6.4 million, or 4%, to \$151.8 million in 2007 from \$145.4 million in 2006, primarily due to the following:

\$3.4 million increase attributable to higher propane prices; and

\$3.2 million increase attributable to higher propane sales volumes; offset by

\$0.2 million decrease related to non-trading derivative activity.

Purchases of Propane Purchases of propane increased \$1.2 million, or 1%, to \$141.0 million in 2007 from \$139.8 million 2006, primarily due to increased purchased volumes, offset by non-cash lower of cost or market inventory adjustments.

Segment Gross Margin Segment gross margin increased \$5.2 million, or 93%, to \$10.8 million in 2007 from \$5.6 million in 2006, primarily as a result of higher per unit margins as a result of changes in contract mix, our ability to utilize various supply sources, non-cash lower of cost or market inventory adjustments, and higher sales volumes.

Operating and Maintenance Expense Operating and maintenance expense increased \$1.1 million, or 52%, to \$3.2 million in 2007 from \$2.1 million in 2006, primarily as a result of higher operating and maintenance expense at the new Midland terminal, which is scheduled to become operational in the second quarter of 2007, and higher labor and benefit costs.

Propane sales increased 759 Bbls/d, or 2%, to 35,358 Bbls/d in 2007 from 34,599 Bbls/d in 2006, due primarily to milder weather in the northeastern United States in 2006.

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This segment includes our NGL transportation pipelines, which includes our Seabreeze and Wilbreeze pipelines, and our 45% interest in Black Lake (\$ in millions, except operating data):

	Three Months Ended March 31,	
	2007	2006
Operating revenues:		
Sales of NGLs	\$ 0.6	\$ 0.2
Transportation and processing services	1.3	1.0
Total operating revenues	1.9	1.2
Purchases of NGLs	0.6	0.3
Segment gross margin (a)	1.3	0.9
Operating and maintenance expense	0.1	0.2
Earnings from equity method investment (b)	(0.2)	
Depreciation and amortization expense	0.3	0.2
Segment net income	\$ 1.1	\$ 0.5
Operating data:		
NGL pipelines throughput (Bbls/d) (b)	27,458	23,425

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

(b) Includes 45% of the throughput volumes and earnings of Black Lake.

Three Months Ended March 31, 2007 vs. Three Months Ended March 31, 2006

Total Operating Revenues Total operating revenues increased \$0.7 million, or 58%, to \$1.9 million in 2007 from \$1.2 million in 2006, due to an increase in revenues attributable to an increase in volumes, as well as the composition of inventory transactions at receipt versus delivery points.

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

Purchases of NGLs Purchases of NGLs increased \$0.3 million, or 100%, to \$0.6 million in 2007 from \$0.3 million 2006, attributable to the composition of inventory transactions at receipt versus delivery points.

Segment Gross Margin Segment gross margin increased \$0.4 million, or 44%, to \$1.3 million in 2007 from \$0.9 million in 2006, primarily due to increased transportation revenue and volumes as a result of the addition of our Wilbreeze pipeline in 2007, which was placed in service in December 2006.

Operating and Maintenance Expense Operating and maintenance expense remained relatively constant in 2007 and 2006.

Earnings from Equity Method Investments Earnings from equity method investments increased to \$0.2 million in 2007 from \$0 in 2006. This increase was as a result of higher Black Lake sales volumes and reduced operating expenses.

Liquidity and Capital Resources

Prior to our acquisition of our wholesale propane logistics business from DCP Midstream, LLC, its sources of liquidity included cash generated from operations and funding from DCP Midstream, LLC. Their cash receipts were deposited in DCP Midstream, LLC's bank accounts and all cash disbursements were made from these accounts. Cash transactions handled by DCP Midstream, LLC for our wholesale propane logistics business were reflected in partners' equity as intercompany advances from DCP Midstream, LLC.

We expect our sources of liquidity to include:

cash generated from operations;

cash distributions from Black Lake;

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borrowings under our revolving credit facility;

cash realized from the liquidation of securities that are pledged under our term loan facility;

issuance of additional partnership units; and

debt offerings.

We anticipate our more significant uses of resources to include:

capital expenditures

business acquisitions; and

quarterly distributions to our unitholders.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions. Our commodity hedging program, as well as any future hedges we enter into, may require us to post collateral depending on commodity price movements. DCP Midstream, LLC has issued parental guarantees for a portion of our commodity hedging instruments that span through 2010 for natural gas swaps and crude oil swaps, 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. We have hedged a significant portion of our anticipated commodity price risk associated with our gathering and processing arrangements through 2010 with natural gas and crude oil swaps, and a significant portion of our anticipated condensate price risk through 2011 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](#) in our 2006 Form 10-K.

Working Capital Working capital is the amount by which current assets exceed current liabilities. Current assets are reduced by our quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, along with other business factors that affect our net income and cash flows. Our working capital generally increases in periods of rising commodity prices and declines in periods of falling commodity prices. However, our working capital requirements do not necessarily change at the same rate as commodity prices. Our working capital is also impacted by the timing of operating cash receipts and disbursements, payments on debt, capital expenditures, and increases or decreases in restricted investments and other non-current assets.

We had working capital of \$35.6 million and \$33.1 million as of March 31, 2007 and December 31, 2006, respectively. The changes in working capital are primarily attributable to the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

Cash Flow Net cash provided by (used in) operating activities, investing activities and financing activities for the three months ended March 31, 2007 and 2006 were as follows (\$ in millions):

Three Months	
Ended March 31,	
2007	2006

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Net cash provided by operating activities	\$ 14.2	\$ 8.2
Net cash used in investing activities	\$ (13.3)	\$ (5.0)
Net cash used in financing activities	\$ (17.7)	\$ (32.2)

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

Net Cash Used in Investing Activities Net cash used in investing activities in the first quarter of 2007 and 2006 was primarily used for: (1) payment of an earnest deposit; (2) 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; and (3) net purchases of available-for-sale securities of \$0.9 million.

Net Cash Used in Financing Activities Net cash used in financing activities during the three months ended March 31, 2007 was primarily comprised of the excess of purchase price over the acquired assets attributable to a payment related to our acquisition of

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our wholesale propane logistics business, and distributions to our unitholders. Net cash used in financing activities during the three months ended March 31, 2006 was primarily comprised of repayments of debt, changes in parent advances and distributions to our unitholders.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 7 of the Notes to Condensed Consolidated Financial Statements in Item 1. Financial Statements.

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. In our Wholesale Propane Logistics and NGL Logistics segments, our capital expenditures may include the construction of new propane terminals and NGL pipelines that would expand our distribution and transportation capabilities.

Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

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

expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets) in each case if such addition, improvement, acquisition or construction is made to increase our operating capacity or revenues or those of 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 \$2.7 million and expansion capital expenditures of \$7.2 million for the year ending December 31, 2007. During the three months ended March 31, 2007, our capital expenditures totaled \$3.4 million, including maintenance capital expenditures of \$0.6 million and expansion capital expenditures of \$2.8 million. We have an agreement with certain producers whereby these producers will reimburse us for certain capital projects completed by us. During the three months ended March 31, 2007, the changes in receivables and collections of maintenance capital expenditures, from DCP Midstream, LLC and producers, were not significant. During the three months ended March 31, 2006, our capital expenditures totaled \$4.7 million, including maintenance capital expenditures of \$1.8 million and expansion capital expenditures of \$2.9 million.

Maintenance capital expenditures in 2007 were lower than 2006 as a result of a higher number of well connects in the first quarter of 2006 versus 2007. Annual expansion capital expenditures in 2007 are expected to increase as a result of the acquisitions detailed above in Recent Events. These increases in capital expenditures in 2007 are offset by decreases as a result of the completion of Wilbreeze in December 2006, an NGL pipeline, for which expansion capital expenditures were approximately \$11.8 million in 2006, and the completion of a substantial portion of our new propane terminal in 2006, partially offset by the remaining cost to complete our new propane terminal incurred in 2007. We expect to fund future capital expenditures with restricted investments, funds generated from our operations, borrowings under our credit facility and the issuance of additional partnership units.

Cash Distributions to Unitholders Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all cash and cash equivalents on hand at the end of the quarter, less certain reserves as identified in the partnership agreement, to unitholders of record on the applicable record date. We made cash distributions to our unitholders of \$7.8 million during the quarter ended March 31, 2007, as compared to \$1.7 million for the same period in 2006. The distribution paid during the quarter ended March 31, 2006, represented the pro rata portion of our Minimum Quarterly Distribution of \$0.35 per unit for the period December 7, 2005, the closing of our initial public offering, through December 31, 2005. We intend to make quarterly distribution payments to our unitholders to the extent we have sufficient cash from operations after the establishment of reserves.

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Description of Credit Agreement On December 7, 2005, we entered into the Credit Agreement, which 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. At March 31, 2007, we had outstanding debt of \$168.0 million under our revolving credit facility, and \$0.2 million of letters of credit outstanding.

We have the option of increasing the size of the revolving credit facility to \$550.0 million with the consent of the issuing lenders.

We had outstanding indebtedness of \$100.0 million under the term loan facility as of March 31, 2007. Amounts repaid under the term loan facility may not be reborrowed. The full balance on the term loan was collateralized, as required by the Credit Agreement, by investments in high-grade securities as of March 31, 2007 for future use in funding capital expenditures (including potential acquisitions) and in order to reduce our cost of borrowings under the term loan facility.

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. Any portion of the term loan balance may be repaid at any time, and we may then have access to a corresponding amount of the collateral securities. Upon any prepayment of term loan borrowings, the amount of our revolving credit facility will automatically increase to the extent that the repayment of our term loan facility is made in connection with an acquisition of assets in the midstream energy business.

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 plus an applicable margin of 0% to 0.025% based on leverage level, 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 or credit rating. As of March 31, 2007, the revolving credit facility bears interest at the weighted-average rate of 5.85% per annum, and the term loan facility bears interest at a rate of 5.47% per annum. The revolving credit facility incurs an annual facility fee of 0.08% to 0.35% 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. The Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 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. The Credit Agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Credit Agreement) of equal or greater than 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 and Off-Balance Sheet Arrangements

A summary of our total contractual cash obligations as of March 31, 2007, is as follows (\$ in millions):

	Total	Payments Due by Period			2012 and Thereafter
		Remainder of 2007	2008-2009	2010-2011	
Long-term debt (a)	\$ 294.0	\$ 5.2	\$ 13.9	\$ 274.9	\$
Operating lease obligations	40.0	6.6	13.6	9.4	10.4
Purchase obligations (b)	0.3	0.3			
Other long-term liabilities (c)	0.5				0.5

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Total	\$ 334.8	\$ 12.1	\$ 27.5	\$ 284.3	\$ 10.9
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- (a) Includes interest payments on long-term debt that has been hedged, because the interest rate is determinable. Interest payments on long-term debt, which has not been hedged, are not included as they are based on floating interest rates and we cannot determine with accuracy the periodic repayment dates or the amounts of the interest payments.

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- (b) Purchase obligations exclude \$96.4 million of accounts payable, \$0.8 million of accrued interest payable and \$6.0 million of other current liabilities recognized on the March 31, 2007 condensed consolidated balance sheet. Purchase obligations also exclude \$1.8 million of current and \$3.8 million of long-term unrealized losses on non-trading derivative and hedging instruments included on the March 31, 2007 condensed 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 \$0.5 million of asset retirement obligations recognized on the March 31, 2007 condensed consolidated balance sheet.

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

Recent Accounting Pronouncements

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

SFAS No. 157, Fair Value Measurements, or SFAS 157 In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard also responds to investors' requests for more information about: (1) the extent to which companies measure assets and liabilities at fair value; (2) the information used to measure fair value; and (3) the effect that fair value measurements have on earnings. SFAS 157 will apply whenever another standard requires (or permits) assets or liabilities to be measured at fair value. SFAS 157 does not expand the use of fair value to any new circumstances. SFAS 157 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 157 on our consolidated results of operations, cash flows or financial position.

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

For an in-depth discussion of our market risks, see *Quantitative and Qualitative Disclosures about Market Risk* in our 2006 Form 10-K.

Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketing servicers and industrial end-users. Our principal customers in the Wholesale Propane Logistics segment are primarily retail propane distributors. In the NGL Logistics Segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Substantially all of our natural gas, propane and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC's corporate credit policy. DCP Midstream, LLC's corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request

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that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC's credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Interest Rate Risk

Interest rates on future credit facility draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances. Based on the unhedged borrowings under our revolving credit facility as of March 31, 2007 of \$43.0 million, a 0.5% movement in the base rate or LIBOR rate would result in an approximately \$0.2 million annualized increase or decrease in interest expense.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing and sales activities. 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. For the year ending December 31, 2007, we expect that a \$1.00 per MMBtu decrease in the price of natural gas, a \$0.10 per gallon decrease in NGL prices and a \$5.00 per barrel decrease in condensate prices would decrease our gross margin by approximately \$0.2 million, \$0.4 million and \$0.1 million, respectively. These sensitivities include the effect of our hedging strategies executed through 2006. Please read [Quantitative and Qualitative Disclosures about Market Risk](#) [Commodity Price Risk](#) [Hedging Strategies](#) in our 2006 Form 10-K for more information about these hedging strategies and our commodity price risk.

As of March 31, 2007, we have hedged a significant portion of our expected natural gas, NGL and condensate commodity price risk through 2010 and our condensate commodity price risk in 2011.

Item 4. *Controls and Procedures* **Evaluation of Disclosure Controls and Procedures**

Our management, including the Chief Financial Officer and the Chief Executive Officer of DCP Midstream GP, LLC, have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and concluded that, as of the end of the period covered by this report, the disclosure controls and procedures are effective in ensuring that all material information required to be filed in this quarterly report has been made known to them in a timely fashion. The required information was effectively recorded, processed, summarized and reported within the time period necessary to prepare this quarterly report. Our disclosure controls and procedures are effective in ensuring that information required to be disclosed in our reports under the Exchange Act are accumulated and communicated to management, including the Chief Financial Officer and the Chief Executive Officer of DCP Midstream GP, LLC, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the three months ended March 31, 2007 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information required for this item is provided in Note 11, Commitments and Contingent Liabilities, included in the Notes to Condensed Consolidated Financial Statements included under Part I. Item 1. Financial Statements, which information is incorporated by reference into this item.

Item 1A. Risk Factors

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006, or our 2006 Form 10-K. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described in our 2006 Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our consolidated results of operations, financial condition and cash flows.

The following is a new or modified risk factor that should be read in conjunction with the risk factors disclosed in our 2006 Form 10-K:

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

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

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

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

In March 2007, we purchased 4,000 common units on the open market to be used for director compensation pursuant to the DCP Midstream Partners, LP Long-Term Incentive Plan. Such units were held as treasury units at March 31, 2007.

Item 6. Exhibits

Exhibit Number	Description
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	

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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.

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SIGNATURES

Pursuant to the requirements 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 May 10, 2007.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

By: /s/ Thomas E. Long
Name: Thomas E. Long
Title: Vice President and Chief Financial Officer
(Principal Financial Officer)

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EXHIBIT INDEX

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