DCP Midstream Partners, LP
Form 10-Q
November 09, 2007
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended: September 30, 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	**03-0567133**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
370 17th Street, Suite 2775 Denver, Colorado	**80202**
(Address of principal executive offices)	**(Zip Code)**

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

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 x 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 x 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 x

As of November 2, 2007, there were outstanding 16,840,326 common limited partner units and 7,142,857 subordinated units.

DCP MIDSTREAM PARTNERS, LP

FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2007

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GLOSSARY OF TERMS

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

Bbls	barrels
Bbls/d	barrels per day
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	million British thermal units, a measurement of energy
MMBtu/d	million British thermal units per day, a measurement of energy
MMcf/d	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 mitigate 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.

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PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2007	December 31, 2006
	($ in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 59.6	$ 46.2
Short-term investments		0.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.5 million and $0.3 million, respectively	46.6	43.4
Affiliates	50.2	34.8
Inventories	28.0	30.1
Unrealized gains on non-trading derivative and hedging instruments	4.9	4.2
Other	0.8	0.3
Total current assets	190.1	159.6
Restricted investments	100.2	102.0
Property, plant and equipment, net	487.9	194.7
Goodwill	86.4	29.3
Intangible assets, net	25.7	2.8
Equity method investments	171.2	170.2
Unrealized gains on non-trading derivative and hedging instruments	4.9	6.5
Other long-term assets	1.4	0.8
Total assets	$ 1,067.8	$ 665.9
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 81.4	$ 66.9
Affiliates	46.1	50.4
Unrealized losses on non-trading derivative and hedging instruments	15.2	0.7
Accrued interest payable	1.3	1.1
Other	12.1	7.4
Total current liabilities	156.1	126.5
Long-term debt	630.0	268.0
Unrealized losses on non-trading derivative and hedging instruments	20.5	2.7
Other long-term liabilities	6.6	1.0
Total liabilities	813.2	398.2

Non-controlling interests	23.2	
Commitments and contingent liabilities		
Partners equity:		
Predecessor equity		164.3
Common unitholders (16,840,326 and 10,357,143 units issued and outstanding, respectively)	346.2	223.4
Class C unitholders (0 and 200,312 units issued and outstanding, respectively)		(20.7)
Subordinated unitholders (7,142,857 convertible units issued and outstanding at both periods)	(103.5)	(101.6)
General partner interest	(4.4)	(5.0)
Accumulated other comprehensive (loss) income	(6.9)	7.3
Total partners equity	231.4	267.7
Total liabilities and partners equity	$ 1,067.8	$ 665.9

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	($ in millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 112.2	$ 110.6	$ 414.1	$ 402.2
Sales of natural gas, propane, NGLs and condensate to affiliates	73.6	44.7	190.2	165.7
Transportation and processing services	4.5	3.8	11.4	11.2
Transportation and processing services to affiliates	4.4	3.2	12.3	9.2
Losses from non-trading derivative activity, net	(4.7)		(19.2)	
(Losses) gains from non-trading derivative activity affiliates, net	(1.4)	0.5	(1.9)	
Total operating revenues	188.6	162.8	606.9	588.3
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	131.3	119.4	423.9	443.7
Purchases of natural gas, propane and NGLs from affiliates	32.0	20.8	115.5	76.4
Operating and maintenance expense	8.1	5.8	21.0	17.3
Depreciation and amortization expense	7.9	3.2	15.8	9.6
General and administrative expense	2.9	4.0	9.9	9.5
General and administrative expense affiliates	2.5	2.3	7.2	6.1
Total operating costs and expenses	184.7	155.5	593.3	562.6
Operating income	3.9	7.3	13.6	25.7
Interest income	1.2	1.7	3.7	4.7
Interest expense	(8.1)	(2.9)	(16.5)	(8.1)
Earnings from equity method investments	10.8	8.2	23.6	24.0
Non-controlling interest in income	(0.3)		(0.3)	
Net income	$ 7.5	$ 14.3	$ 24.1	$ 46.3
Less:				
Net income attributable to predecessor operations		(4.6)	(3.6)	(22.4)
General partner interest in net income	(0.9)	(0.2)	(1.5)	(0.5)
Net income allocable to limited partners	$ 6.6	$ 9.5	$ 19.0	$ 23.4
Net income per limited partner unit basic and diluted	$ 0.29	$ 0.51	$ 0.89	$ 1.32
Weighted-average limited partner units outstanding basic and diluted	22.3	17.5	19.3	17.5

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	($ in millions)			
Net income	$ 7.5	$ 14.3	$ 24.1	$ 46.3
Other comprehensive (loss) income:				
Reclassification of cash flow hedges into earnings	(0.7)	(0.7)	(2.8)	(1.4)
Net unrealized (losses) gains on cash flow hedges	(5.7)	10.1	(11.4)	7.3
Total other comprehensive (loss) income	(6.4)	9.4	(14.2)	5.9
Total comprehensive income	$ 1.1	$ 23.7	$ 9.9	$ 52.2

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2007	2006
	($ in millions)	
OPERATING ACTIVITIES:		
Net income	$ 24.1	$ 46.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	15.8	9.6
Earnings from equity method investments, net of distributions	3.5	(4.5)
Non-controlling interest in income	0.3	
Other, net	(0.7)	(1.8)
Change in operating assets and liabilities which provided (used) cash, net of effects from acquisitions:		
Accounts receivable	(2.1)	68.5
Inventories	2.1	11.1
Net unrealized losses on non-trading derivative and hedging instruments	19.9	0.2
Accounts payable	(2.2)	(90.3)
Accrued interest	0.2	(0.4)
Other current assets and liabilities	4.3	1.1
Other long-term assets and liabilities	0.9	0.4
Net cash provided by operating activities	66.1	40.2
INVESTING ACTIVITIES:		
Capital expenditures	(11.6)	(18.4)
Acquisition of subsidiaries of Momentum Energy Group, Inc., net of cash acquired	(142.0)	
Acquisition of assets	(191.3)	
Acquisition of equity method investees	(153.3)	
Investments in equity method investees	(4.3)	(9.0)
Payment of earnest deposit	(9.0)	
Refund of earnest deposit	9.0	
Proceeds from sales of assets	0.1	0.1
Purchases of available-for-sale securities	(6,789.8)	(5,377.0)
Proceeds from sales of available-for-sale securities	6,793.1	5,375.5
Net cash used in investing activities	(499.1)	(28.8)
FINANCING ACTIVITIES:		
Borrowings of debt	569.0	
Repayments of debt	(207.0)	(20.1)
Proceeds from issuance of common units, net of offering costs	228.5	
Payment of deferred financing costs	(0.6)	
Purchase of treasury units	(0.2)	
Excess purchase price over acquired assets	(100.3)	
Net change in advances from DCP Midstream, LLC	(14.6)	(7.0)
Distributions to unitholders	(28.8)	(14.7)
Contributions from DCP Midstream, LLC	0.4	3.3

Net cash provided by (used in) financing activities	446.4	(38.5)
Net change in cash and cash equivalents	13.4	(27.1)
Cash and cash equivalents, beginning of period	46.2	42.2
Cash and cash equivalents, end of period	$ 59.6	$ 15.1
Supplementary disclosure of cash flow information:		
Cash paid for interest, net of capitalized interest	$ 17.3	$ 8.4

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 Northern Louisiana system assets; our Southern Oklahoma system (acquired in May 2007); our limited liability company interests in DCP East Texas Holdings, LLC, or East Texas, and Discovery Producer Services LLC, or Discovery (acquired in July 2007); our Colorado and Wyoming systems (acquired in August 2007); our NGL transportation pipelines; and our wholesale propane logistics business (acquired in November 2006).

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 conjunction with DCP Midstream, LLC s acquisition of Momentum Energy Group, Inc., or MEG, in August 2007, we acquired certain subsidiaries of MEG from DCP Midstream, LLC. The subsidiaries of MEG own gathering, processing and compression assets in Colorado and Wyoming.

In July 2007, we acquired our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and our non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, from DCP Midstream, LLC, in a transaction among entities under common control. Accordingly, these condensed consolidated financial statements include the historical results of the interest in East Texas and Discovery, and the historical results of the Swap, for all periods 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, the equity interests in East Texas and Discovery, and the Swap, collectively 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, and the supplemental consolidated financial statements and notes thereto included in our Form 8-K filed on October 17, 2007.

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.

Reclassifications Certain prior period amounts have been reclassified in the condensed consolidated financial statements to conform to the current period presentation.

Accounting for Risk Management and Hedging Activities and Financial Instruments Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. Therefore, we are using the mark-to-market method of accounting for all commodity cash flow hedges beginning in July 2007. As a result, the remaining net loss of $2.5 million deferred in accumulated other comprehensive income, or AOCI, as of September 30, 2007 will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

***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. Acquisitions

Gathering and Compression Assets

In August 2007, we acquired certain subsidiaries of MEG from DCP Midstream, LLC for approximately $165.8 million, subject to final closing adjustments. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments to date that include a liability of $9.0 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of revolver and term loan borrowings under our amended credit agreement, the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we sold 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate. The proceeds from this private placement were used to purchase high-grade securities to fully secure our term loan borrowing. In connection with this common unit purchase agreement, we have a registration rights agreement that requires us to register the units within 90 days of the close of the private placement, and have met the requirement to file a registration statement with the SEC. In addition, the registration rights agreement requires DCP Partners to use its commercially reasonable efforts to cause the registration statement to become effective within 180 days of the closing of the private placement. If the registration statement covering the common units is not declared effective by the SEC within 180 days of the closing of the private placement, then DCP Partners will be liable to the purchasers for liquidated damages of 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for the first 60 days following the 180th day, increasing by an additional 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period.

The transfer of the MEG subsidiaries between DCP Midstream, LLC and us represents a transfer between entities under common control. Transfers between entities under common control are accounted for at DCP Midstream, LLC s carrying value, similar to the pooling method. DCP Midstream, LLC recorded its acquisition of the MEG subsidiaries under the purchase method of accounting, whereby the assets and liabilities were recorded at their respective fair values as of the date of the acquisition, including goodwill of approximately $57.1 million. DCP Midstream, LLC obtained third-party valuations for property, plant and equipment, and intangible assets. Because of the recency of this transaction, however, the values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained. When finalized, material adjustments to goodwill may result.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The purchase price allocation was determined based upon third-party valuations of property, plant and equipment, and intangible assets ($ in millions):

Cash consideration	$ 153.8
Payable to DCP Midstream, LLC	9.0
Common limited partner units	12.0
Aggregate consideration	$ 174.8
The preliminary purchase price allocation is as follows:	
Cash	$ 11.8
Accounts receivable	14.0
Other assets	1.5
Property, plant and equipment	123.1
Goodwill	57.1
Intangible assets	10.9
Accounts payable	(13.5)
Other liabilities	(7.2)
Non-controlling interest in joint venture	(22.9)
Total purchase price allocation	$ 174.8

On July 1, 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC for aggregate consideration of approximately $271.3 million, consisting of approximately $243.7 million in cash, including net working capital of $1.3 million and other adjustments, the issuance of 620,404 common units to DCP Midstream, LLC valued at $27.0 million and the issuance of 12,661 general partner equivalent units valued at $0.6 million. We financed the cash portion of this transaction with borrowings of $245.9 million under our amended credit facility. The 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 $118.0 million excess purchase price over the historical basis of the net acquired assets was recorded as a reduction to partners equity, and the $27.6 million of common and general partner equivalent units issued as partial consideration for this transaction was recorded as an increase to partners equity, for financial accounting purposes.

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

In April 2007, we acquired certain gathering and compression assets located in Northern Louisiana from Laser Gathering Company, LP for approximately $10.2 million, subject to customary purchase price adjustments.

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

Wholesale Propane Logistics Business

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

The 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.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Combined Financial Information

The following table presents the impact on the condensed consolidated balance sheet as of December 31, 2006, adjusted for the acquisition of East Texas and Discovery, from DCP Midstream, LLC ($ in millions):

As of December 31, 2006

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following tables present the impact on the condensed consolidated statements of operations, adjusted for the acquisition of our wholesale propane logistics business, and for the acquisition of East Texas and Discovery, from DCP Midstream, LLC, for the three and nine months ended September 30, 2006 ($ in millions):

Three Months Ended September 30, 2006

	DCP Midstream Partners, LP	Wholesale Propane Logistics Business	East Texas and Discovery	Combined DCP Midstream Partners, LP
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 95.0	$ 60.3	$	$ 155.3
Transportation and other	7.0	0.5		7.5
Total operating revenues	102.0	60.8		162.8
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	80.1	60.1		140.2
Operating and maintenance expense	3.6	2.2		5.8
Depreciation and amortization expense	3.0	0.2		3.2
General and administrative expense	4.4	1.9		6.3
Total operating costs and expenses	91.1	64.4		155.5
Operating income (loss)	10.9	(3.6)		7.3
Interest expense, net	1.2			1.2
Earnings from equity method investments			8.2	8.2
Net income (loss)	$ 9.7	$ (3.6)	$ 8.2	$ 14.3

Nine Months Ended September 30, 2006

	DCP Midstream Partners, LP	Wholesale Propane Logistics Business	East Texas and Discovery	Combined DCP Midstream Partners, LP
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 296.6	$ 271.3	$	$ 567.9
Transportation and other	20.4			20.4
Total operating revenues	317.0	271.3		588.3

Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	257.9	262.2		520.1
Operating and maintenance expense	10.9	6.4		17.3
Depreciation and amortization expense	8.9	0.7		9.6
General and administrative expense	12.1	3.5		15.6
Total operating costs and expenses	289.8	272.8		562.6
Operating income (loss)	27.2	(1.5)		25.7
Interest expense, net	3.4			3.4
Earnings from equity method investments	0.1		23.9	24.0
Net income (loss)	$ 23.9	$ (1.5)	$ 23.9	$ 46.3

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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

was allocated based on the predecessor s proportionate net investment (consisting of property, plant and equipment, net, equity method investments, and intangible assets, net) as compared to DCP Midstream, LLC s net investment. In management s estimation, the allocation methodologies used were reasonable and resulted in an allocation to the predecessors of their respective costs of doing business, which were borne by DCP Midstream, LLC.

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The Omnibus Agreement: (1) states that the annual fee of $4.8 million for the initial assets under the agreement was fixed at such amount for 2006, which increased to $5.0 million for 2007; (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; (3) effective May 2007, includes an additional annual fee of $0.2 million related to the Southern Oklahoma asset acquisition; (4) effective July 2007, includes an additional annual fee of $0.2 million related to the acquisition of our 40% limited liability company interest in Discovery from DCP Midstream, LLC; (5) effective August 2007, includes an additional annual fee of $0.6 million to account for additional services provided to us; and (6) effective August 2007, includes an additional annual fee of $1.6 million related to our acquisition of certain subsidiaries of MEG from DCP Midstream, LLC. All of the fees under the Omnibus Agreement are subject to adjustment annually for changes in the Consumer Price Index.

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, 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

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).

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 $15.0 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DCP Midstream, LLC has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

Additionally, DCP Midstream, LLC will indemnify us for losses attributable to title defects, retained assets and liabilities (including 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 Pipe Line Company, or Black Lake, associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from 2005 through early 2008. 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.

In connection with our acquisitions of East Texas and Discovery from DCP Midstream, LLC, an affiliate of DCP Midstream, LLC will indemnify us for one year following the closing on July 1, 2007 for the breach of the representations and warranties made under the acquisition agreement and certain litigation, environmental matters, title defects and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, the same affiliate of DCP Midstream, LLC agreed to indemnify us for one year after closing for the overpayment or underpayment of trade payables or receivables that pertain to periods prior to closing and agreed to indemnify us for two years after closing for any claims for fines or penalties of any governmental authority for periods prior to the closing and that are associated with certain East Texas assets that were formerly owned by Gulf South and UP Fuels. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $2.7 million and is subject to a maximum liability of $27.0 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 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.

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.

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

In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for capital projects, which were forecasted to be completed prior to our initial public offering, but were not completed by that date. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $0.3 million and $3.3 million during the nine months ended September 30, 2007 and 2006, respectively, to reimburse us for the capital costs we incurred, primarily for growth capital projects.

In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for certain Discovery capital projects, which were forecasted to be completed prior to our acquisition of a 40% limited liability company interest in Discovery. Pursuant to the letter agreement, we have recognized as accounts receivable-affiliates $0.3 million from DCP Midstream, LLC as of September 30, 2007.

DCP Midstream, LLC was a significant customer during the three and nine months ended September 30, 2007 and 2006.

Duke Energy

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

ConocoPhillips

We have multiple agreements whereby we provide a variety of services to ConocoPhillips and its affiliates. The agreements include fee-based and percentage-of-proceeds gathering and processing arrangements, gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received $2.4 million and $2.7 million of capital reimbursements during the nine months ended September 30, 2007 and 2006, respectively.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following table summarizes the transactions with affiliates ($ in millions):

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$ 70.3	$ 44.7	$ 184.2	$ 165.6
Transportation and processing services	$ 1.5	$ 1.0	$ 4.4	$ 3.5
Purchases of natural gas, propane and NGLs	$ 24.1	$ 16.7	$ 94.1	$ 64.7
(Losses) gains from non-trading derivative activity, net	$ (1.4)	$ 0.5	$ (1.9)	$
General and administrative expense	$ 2.5	$ 2.3	$ 7.2	$ 6.1
Duke Energy:				
Purchases of natural gas, propane and NGLs	$	$ 1.5	$	$ 3.4
ConocoPhillips:				
Sales of natural gas, propane, NGLs and condensate	$ 3.3	$	$ 6.0	$ 0.1
Transportation and processing services	$ 2.9	$ 2.2	$ 7.9	$ 5.7
Purchases of natural gas, propane and NGLs	$ 7.9	$ 2.6	$ 21.4	$ 8.3

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

	September 30, 2007	December 31, 2006
DCP Midstream, LLC:		
Accounts receivable	$ 43.8	$ 30.0
Accounts payable	$ 44.2	$ 46.6
Spectra Energy:		
Accounts receivable	$	$
Accounts payable	$ 0.2	$
Duke Energy:		
Accounts receivable	$	$ 0.2
Accounts payable	$	$ 1.8
ConocoPhillips:		
Accounts receivable	$ 6.4	$ 4.6
Accounts payable	$ 1.7	$ 2.0

The following summarizes the unrealized gains and unrealized losses on non-trading derivative and hedging instruments with affiliates ($ in millions):

	September 30, 2007	December 31, 2006
DCP Midstream, LLC:		

Unrealized gains current	$		$	0.3
Unrealized losses current	$	(1.6)	$	(0.2)

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Property, Plant and Equipment

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

	Depreciable Life	September 30, 2007	December 31, 2006
Gathering systems	15 30 Years	$ 366.7	$ 107.3
Processing plants	25 30 Years	91.2	53.2
Terminals	25 30 Years	24.2	8.2
Transportation	25 30 Years	138.9	139.6
General plant	3 5 Years	4.1	3.6
Construction work in progress		11.4	16.2
Property, plant and equipment		636.5	328.1
Accumulated depreciation		(148.6)	(133.4)
Property, plant and equipment, net		$ 487.9	$ 194.7

7. Goodwill and Intangible Assets

The increase in goodwill during the third quarter of 2007 consists of the amount that we recognized in connection with our acquisition of the MEG subsidiaries. Our annual goodwill impairment test, as of August 31, 2007, indicated that our reporting units fair values exceed their carrying or book values. Accordingly, no impairment of goodwill is indicated. The change in the carrying amount of goodwill is as follows:

	September 30, 2007	December 31, 2006
Beginning of period	$ 29.3	$ 29.3
Acquisitions	57.1	
End of period	$ 86.4	$ 29.3

Intangible assets consist primarily of commodity purchase contracts and relationships. The gross carrying amount and accumulated amortization for the commodity purchase contracts and other intangible assets are included in the accompanying condensed consolidated balance sheets as intangible assets, net, and were as follows ($ in millions):

	September 30, 2007	December 31, 2006
Gross carrying amount	$ 27.8	$ 4.4

Accumulated amortization		(2.1)		(1.6)
Intangible assets, net	$	25.7	$	2.8

Intangible assets increased as a result of the Southern Oklahoma and MEG acquisitions, through which $12.5 million and $10.9 million, respectively, of intangible assets were acquired. Intangible assets have an average life of 20 years and are being amortized through 2032.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Equity Method Investments

The following table summarizes our equity method investments ($ in millions):

	Percentage of Ownership as of	Carrying Value as of	
	September 30, 2007 and December 31, 2006	September 30, 2007	December 31, 2006
Discovery Producer Services LLC	40%	$ 113.5	$ 113.4
DCP East Texas Holdings, LLC	25%	50.9	50.9
Black Lake Pipe Line Company	45%	6.6	5.7
Other	50%	0.2	0.2
Total equity method investments		$ 171.2	$ 170.2

Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a 32,000 Bbl/d natural gas liquids fractionator plant near Paradis, Louisiana, a natural gas pipeline from offshore deep water in the Gulf of Mexico that transports gas to our processing plant in Larose, Louisiana with a design capacity of 600 MMcf/d and approximately 173 miles of pipe, and several laterals expanding their presence in the Gulf. There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $44.9 million and $48.6 million at September 30, 2007 and December 31, 2006, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

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

Black Lake owns a 317-mile NGL pipeline, with a throughput capacity of approximately 40 MBbls/d. The pipeline receives NGLs from a number of gas plants in Louisiana and Texas. There was a deficit between the carrying amount of the investment and the underlying equity of Black Lake of $6.4 million and $6.7 million at September 30, 2007 and December 31, 2006, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

Earnings from equity method investments for the three and nine months ended September 30, 2007 and 2006 were as follows ($ in millions):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2007	2006	2007	2006
Discovery Producer Services LLC	$ 6.5	$ 5.3	$ 14.1	$ 13.9
DCP East Texas Holdings, LLC	3.8	2.9	8.5	10.0
Black Lake Pipe Line Company and other	0.5		1.0	0.1

Total earnings from equity method investments	$	10.8	$	8.2	$	23.6	$	24.0
Distributions from equity method investments	$	8.6	$	8.4	$	27.1	$	19.5
Earnings from equity method investments, net of distributions	$	2.2	$	(0.2)	$	(3.5)	$	4.5

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following summarizes financial information of our equity method investments ($ in millions):

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Statements of operations:				
Operating revenue	$ 180.2	$ 161.1	$ 503.4	$ 526.5
Operating expenses	$ 151.4	$ 140.5	$ 442.7	$ 463.6
Net income	$ 28.9	$ 21.6	$ 61.5	$ 64.7

	September 30, 2007	December 31, 2006
Balance sheet:		
Current assets	$ 140.9	$ 108.9
Non-current assets	638.9	630.7
Current liabilities	135.2	94.8
Non-current liabilities	16.8	6.0
Net assets	$ 627.8	$ 638.8

9. Debt

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

	Principal Amount September 30, 2007	Principal Amount December 31, 2006
Revolving credit facility, weighted-average interest rate of 5.74% at September 30, 2007, due June 21, 2012	$ 530.0	$ 168.0
Term loan facility, interest rate of 5.23% at September 30, 2007, due June 21, 2012	100.0	100.0
Total long-term debt	$ 630.0	$ 268.0

Credit Agreements

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

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

At September 30, 2007 and December 31, 2006, we had $0.2 million of letters of credit outstanding. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying condensed consolidated balance sheets as of September 30, 2007 and December 31, 2006. We have incurred $0.6 million of debt issuance costs associated with the Amended Credit Agreement. These expenses are deferred as other long-term assets in the condensed consolidated balance sheet and will be amortized over the term of the Amended Credit Agreement.

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

The Amended Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended Credit Agreement) of not more than 5.75 to 1.0 through and including the quarter ended June 30, 2007 and 5.0 to 1.0 thereafter, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

midstream energy business of not more than 5.50 to 1.0. The Amended Credit Agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loan

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

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

10. 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.

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

In June 2007, we entered into a private placement agreement with a group of institutional investors for $130.0 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $128.5 million, net of offering costs. In connection with this private placement agreement, we entered into a registration rights agreement with institutional investors that requires us to register the units by the earlier of within 120 days of the close of the private placement or when a registration statement is filed to register the units to be issued and sold by us in connection with the MEG acquisition, and we have met the requirement to file a registration statement with the SEC. In addition the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 210 days of the closing of the private placement, or we will be liable to the institutional investors for liquidated damages of 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for the first 60 days following the 210th day, increasing by an additional 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period.

In August 2007, we sold 2,380,952 common units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. In connection with this common unit purchase agreement, we have a registration rights agreement that requires us to register the units within 90 days of the close of the private placement, and have met the requirement to file a registration statement with the SEC. In addition, the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 180 days of the closing of the private placement. If the registration statement covering the common units is not declared effective by the SEC within 180 days of the closing of the private placement, then we will be liable to the purchasers for liquidated damages of 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for the first 60 days following the 180th day, increasing by an additional 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period.

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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

General Partner Interest and Incentive Distribution Rights Prior to June 2007, the general partner was entitled to 2% of all quarterly distributions that we make prior to our liquidation. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its general partner interest. The general partner s 2% interest in these distributions was reduced to 1.7% in June 2007 as a result of the issuance of the 3,005,780 common limited partner units in conjunction with a private placement agreement, and was reduced to 1.5% in August 2007 as a result of the issuance of 2,656,687 common limited partner units in conjunction with the MEG acquisition.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner s incentive distribution rights were not reduced as a result of these private placement agreements, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 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. On July 2, 2007, the Class C units were converted to common units.

Subordinated Units All of the subordinated units are held by DCP Midstream, LLC. Our partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to $0.35 per common unit, or the Minimum Quarterly Distribution, plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The subordination period has an early termination provision that permits 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2008 and the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in the partnership agreement are satisfied. 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 are being used for director compensation pursuant to the DCP Midstream Partners, LP Long-Term Incentive Plan, or LTIP. In August 2007, these units were issued to our General Partner.

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

first, to the common unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;

second, to the common unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;

third, to the subordinated unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;

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fourth, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter (the First Target Distribution);

fifth, 13% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter (the Second Target Distribution);

sixth, 23% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter (the Third Target Distribution); and

thereafter, 48% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders (the Fourth Target Distribution).

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

first, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;

second, 13% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;

third, 23% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and

thereafter, 48% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders.

The following table presents our cash distributions paid in 2007 and 2006 ($ in millions, except per unit distribution amounts):

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

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

11. Risk Management and Hedging Activities

The impact of our derivative activity on our results of operations and financial position is summarized below ($ in millions):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2007	2006	2007	2006
Commodity cash flow hedges:				
Gains (losses) due to ineffectiveness	$	$ 0.1	$	$ (0.4)
Gains reclassified into earnings	$ 0.5	$ 0.7	$ 2.3	$ 1.4
Commodity non-trading derivative activity:				
(Losses) gains from non-trading derivative activity	$ (6.1)	$ 0.5	$ (21.1)	$
Interest rate cash flow hedges:				
Gains reclassified into earnings	$ 0.2	$	$ 0.5	$

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	September 30, 2007	December 31, 2006
Commodity cash flow hedges:		
Net deferred (losses) gains in AOCI	$ (2.5)	$ 6.9
Interest rate cash flow hedges:		
Net deferred (losses) gains in AOCI	$ (4.4)	$ 0.4

For the three and nine months ended September 30, 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.

Commodity Cash Flow Hedges We use NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGLs, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was accumulated in AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to the condensed consolidated statements of operations in the same accounts as the item being hedged.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. Therefore, we are using the mark-to-market method of accounting for all commodity cash flow hedges. As a result, the remaining net loss of $2.5 million deferred in AOCI as of September 30, 2007 will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings. Deferred net losses of $0.4 million are expected to be reclassified during the next 12 months. Subsequent to July 1, 2007, the changes in fair value of these financial derivatives are included in gains and losses from non-trading derivative activity in the condensed consolidated statements of operations.

Commodity Fair Value Hedges We use fair value hedges to mitigate risk to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) to reduce our 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 and nine months ended September 30, 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 and nine months ended September 30, 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 variability across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings. 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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In August 2007, in conjunction with our acquisition of certain MEG subsidiaries we acquired a series of financial derivatives to mitigate a portion of the commodity price exposure associated with our Powder River Basin assets. These derivatives consist of natural gas swap contracts for 3,460 MMBtu/d through December 2007 and 3,320 MMBtu/d through June 2008, at an average price of $6.85 per MMBtu, and NGL swap contracts for 14,620 gallons per day through December 2007 and 14,310 gallons per day through June 2008, at an average price of $0.97 per gallon.

In July 2007, we acquired the Swap, a financial derivative, entered into by DCP Midstream, LLC in March 2007, to mitigate a portion of the commodity price exposure associated with the acquisition on July 1, 2007 of a 25% limited liability company interest in East Texas and a 40% limited liability company interest in Discovery. This contract consists of crude oil swaps at $66.72/Bbl for 1,100 Bbls/d through 2007, 1,000 Bbls/d through 2008, 925 Bbls/d through 2009, 900 Bbls/d through 2010, 875 Bbls/d through 2011 and 850 Bbls/d through 2012.

In May 2007, we executed a series of financial derivatives to mitigate a portion of the commodity exposure associated with the Southern Oklahoma asset acquisition. We entered into natural gas swap contracts for 1,500 MMBtu/d at $7.54 per MMBtu and into crude oil swap contracts for 650 Bbls/d at $67.60 per Bbl for a term from June 2007 through December 2013. In June 2007, we executed a series of financial derivatives to mitigate a portion of the commodity price exposure associated with our Northern Louisiana system assets. We entered into crude oil swap contracts for 250 Bbls/d at $71.35/Bbl for 2011, 600 Bbls/d at $71.00/Bbl for 2012 and 600 Bbls/d at $71.20/Bbl for 2013.

Interest Rate Cash Flow Hedges In August 2007, we entered into interest rate swap agreements to convert $200.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. These interest rate swaps commenced on September 21, 2007, expire on June 21, 2012 and re-price prospectively approximately every 90 days. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation.

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 through December 7, 2010. 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.

The effective portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheets. As of September 30, 2007, $0.9 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings; however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings.

Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 4.68% to 5.19%, and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

12. Equity-Based Compensation

Total compensation cost for equity-based arrangements was as follows ($ in millions):

	Three Months Ended	Nine Months Ended
	September 30,	September 30,

	2007	2006	2007	2006
Performance Units	$	$ 0.1	$ 0.5	$ 0.2
Phantom Units	0.1	0.2	0.5	0.3
Total compensation cost	$ 0.1	$ 0.3	$ 1.0	$ 0.5

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 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.

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

At September 30, 2007, there was approximately $1.3 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 1.8 years. The following table presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2006	23,090	$ 26.96	
Granted	29,610	$ 37.29	
Forfeited	(5,740)	$ 31.39	
Outstanding at September 30, 2007	46,960	$ 32.93	$ 42.98
Expected to vest	46,960	$ 32.93	$ 42.98

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.

Phantom Units In conjunction with our initial public offering, in January 2006 the General Partner s board of directors awarded phantom LPUs, or Phantom Units, to key employees, and to directors who are not officers or employees of affiliates of the General Partner. Of these Phantom Units, 15,700 units will vest upon the three year anniversary of the grant date, and 5,332 units vest ratably over two years. Each Phantom Unit includes a DER, which is paid quarterly in arrears.

In May 2007, we granted 4,000 Phantom Units under the LTIP to directors who are not officers or employees of affiliates of the General Partner as part of their annual director fees for 2007. These Phantom Units will fully vest six months following the grant date. Each Phantom Unit includes a DER, which is paid quarterly in arrears.

In August 2007, we granted 500 Phantom Units under the LTIP to a director who is not an officer or employee of affiliates of the General Partner as part of his annual director fees for 2007. These Phantom Units will fully vest six months following the grant date. Each Phantom Unit includes a DER, which is paid quarterly in arrears.

At September 30, 2007, there was approximately $0.4 million of unrecognized compensation expense related to the Phantom Units that is expected to be recognized over a weighted-average period of 0.8 years. The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2006	24,700	$ 24.05	
Granted	4,500	$ 42.90	
Forfeited	(1,000)	$ 24.05	
Vested or paid in cash	(2,668)	$ 24.05	
Outstanding at September 30, 2007	25,532	$ 27.37	$ 42.98
Expected to vest	25,532	$ 27.37	$ 42.98

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

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We intend to settle the awards issued under the LTIP in cash upon vesting, with the exception of the units granted in May 2007. 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 nine months ended September 30, 2007, 2,668 awards vested and were settled in cash for $0.1 million. No awards were vested or settled during the nine months ended September 30, 2006.

13. 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 three months ended September 30, 2007, our aggregate net income per LPU was less than the First Target Distribution level, and as a result there was no impact on our calculation of earnings per LPU. During the three months ended September 30, 2006, our aggregate net income per LPU exceeded the Third Target Distribution level, and as a result we allocated $0.6 million in additional earnings to the general partner.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income	$ 7.5	$ 14.3	$ 24.1	$ 46.3
Less:				
Net income attributable to predecessor operations		(4.6)	(3.6)	(22.4)
Net income attributable to the partnership	7.5	9.7	20.5	23.9
Less: General partner interest in net income	(0.9)	(0.2)	(1.5)	(0.5)
Limited partners interest in net income	6.6	9.5	19.0	23.4

Less: Additional earnings allocation to general partner		(0.6)	(1.8)	(0.3)
Net income available to limited partners	$ 6.6	$ 8.9	$ 17.2	$ 23.1
Net income per LPU basic and diluted	$ 0.29	$ 0.51	$ 0.89	$ 1.32

14. Commitments and Contingent Liabilities

Litigation

Driver In August 2007, Driver Pipeline Company, Inc., or Driver, filed a lawsuit against DCP Midstream, LP, an affiliate of the owner of our general partner, in District Court, Jackson County, Texas. The litigation stems from an ongoing commercial dispute involving the construction of our Wilbreeze pipeline, which was completed in December 2006. Driver was the primary contractor for construction of the pipeline and the construction process was managed for us by DCP Midstream, LP. Driver claims damages in the amount of $2.4 million for breach of contract. We believe Driver s position in this litigation is without merit and we intend to

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vigorously defend ourselves against this claim. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated financial position.

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

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

15. 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 Northern Louisiana system assets, the Southern Oklahoma system that was acquired in May 2007, our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and the losses associated with the Swap acquired in July 2007, and the assets of the MEG subsidiaries located in Colorado and Wyoming that were acquired in August 2007.

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 pipeline terminal 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 that runs from northern Louisiana to southeastern Texas. The Wilbreeze transportation pipeline began operations in December 2006.

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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 September 30, 2007

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(b)	Total
Total operating revenue	$ 118.6	$ 66.7	$ 3.3	$	$ 188.6
Gross margin (a)	$ 22.0	$ 1.9	$ 1.4	$	$ 25.3
Operating and maintenance expense	5.4	2.5	0.2		8.1
Depreciation and amortization expense	7.4	0.3	0.2		7.9
General and administrative expense				5.4	5.4
Earnings from equity method investments	10.3		0.5		10.8
Interest income				1.2	1.2
Interest expense				8.1	8.1
Non-controlling interest in income	0.3				0.3
Net income (loss)	$ 19.2	$ (0.9)	$ 1.5	$ (12.3)	$ 7.5
Capital expenditures	$ 3.1	$ 0.6	$ 0.3	$	$ 4.0

Three Months Ended September 30, 2006

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(b)	Total
Total operating revenues	$ 100.4	$ 60.8	$ 1.6	$	$ 162.8
Gross margin (a)	$ 20.7	$ 0.7	$ 1.2	$	$ 22.6
Operating and maintenance expense	3.1	2.2	0.5		5.8
Depreciation and amortization expense	2.7	0.2	0.3		3.2
General and administrative expense				6.3	6.3
Earnings from equity method investments	8.2				8.2
Interest income				1.7	1.7
Interest expense				2.9	2.9
Net income (loss)	$ 23.1	$ (1.7)	$ 0.4	$ (7.5)	$ 14.3

Capital expenditures	$ 0.2	$ 2.2	$ 3.9	$	$ 6.3

Nine Months Ended September 30, 2007

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(b)	Total
Total operating revenue	$ 306.3	$ 293.7	$ 6.9	$	$ 606.9
Gross margin (a)	$ 47.3	$ 16.5	$ 3.7	$	$ 67.5
Operating and maintenance expense	12.6	7.8	0.6		21.0
Depreciation and amortization expense	14.1	0.7	1.0		15.8
General and administrative expense				17.1	17.1
Earnings from equity method investments	22.6		1.0		23.6
Interest income				3.7	3.7
Interest expense				16.5	16.5
Non-controlling interest in income	0.3				0.3
Net income (loss)	$ 42.9	$ 8.0	$ 3.1	$ (29.9)	$ 24.1
Capital expenditures	$ 7.2	$ 3.2	$ 1.2	$	$ 11.6

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Nine Months Ended September 30, 2006

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(b)	Total
Total operating revenues	$ 312.8	$ 271.3	$ 4.2	$	$ 588.3
Gross margin (a)	$ 55.9	$ 9.1	$ 3.2	$	$ 68.2
Operating and maintenance expense	10.1	6.4	0.8		17.3
Depreciation and amortization expense	8.2	0.7	0.7		9.6
General and administrative expense				15.6	15.6
Earnings from equity method investments	23.9		0.1		24.0
Interest income				4.7	4.7
Interest expense				8.1	8.1
Net income (loss)	$ 61.5	$ 2.0	$ 1.8	$ (19.0)	$ 46.3
Capital expenditures	$ 6.1	$ 7.4	$ 4.9	$	$ 18.4

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

	September 30, 2007	December 31, 2006
Segment long-term assets:		
Natural Gas Services (c)	$ 683.5	$ 311.7
Wholesale Propane Logistics	52.3	50.2
NGL Logistics	35.7	35.1
Other (d)	106.2	109.3
Total long-term assets	877.7	506.3
Current assets	190.1	159.6
Total assets	$ 1,067.8	$ 665.9

(a) Gross margin consists of total operating revenues less purchases of natural gas, propane and NGLs. Gross margin is viewed as a non-GAAP measure under the rules of the SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

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

(c) Long-term assets for our Natural Gas Services segment increased as of September 30, 2007 as a result of our Southern Oklahoma asset acquisition in May 2007, and our acquisition of certain MEG subsidiaries in August 2007.

(d) Other long-term assets not allocable to segments consist of restricted investments, unrealized gains on non-trading derivative and hedging instruments and other long-term assets.

16. Subsequent Events

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

On October 24, 2007, the board of directors of the General Partner declared a quarterly distribution of $0.55 per unit, payable on November 14, 2007 to unitholders of record on November 7, 2007. This distribution of $0.55 per unit exceeds the Fourth Target Distribution level (see Note 10 for discussion of distributions of available cash).

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

In October 2007, we received a distribution of $5.6 million from Discovery for the third quarter of 2007.

In October 2007, we filed with the SEC a registration statement on Form S-3, which will, upon effectiveness, allow us to register the 3,005,780 common limited partner units represented in the June private placement agreement and the 2,380,952 common limited partner units represented in the August private placement agreement.

In November 2007, we were required to have posted collateral with certain counterparties to our commodity derivative instruments of approximately $9.0 million.

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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, 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, and the supplemental consolidated financial statements and notes thereto included in our Form 8-K filed on October 17, 2007. We refer to the assets, liabilities and operations of our wholesale propane logistics business, which we acquired from DCP Midstream, LLC in November 2006, and of our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007, collectively as our predecessors.

Overview

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

- our Natural Gas Services segment, which consists of (1) our Northern Louisiana natural gas gathering, processing and transportation system; (2) our Southern Oklahoma system acquired in May 2007; (3) our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and the Swap, acquired in July 2007 from DCP Midstream, LLC; and (4) certain subsidiaries of Momentum Energy Group, Inc, or MEG, acquired from DCP Midstream, LLC in August 2007;

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

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

The financial information contained herein includes, for each period presented, our accounts, and the assets, liabilities and operations of (1) our wholesale propane logistics business that we acquired in November 2006 and (2) our 25% interest in East Texas, 40% interest in Discovery, and the Swap that we acquired in July 2007, from DCP Midstream, LLC in transactions among entities under common control. Accordingly, our financial information includes the historical results of our predecessors for all periods presented.

Recent Events

In November 2007, we were required to have posted collateral with certain counterparties to our commodity derivative instruments of approximately $9.0 million.

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

In October 2007, we filed with the SEC a registration statement on Form S-3, which will, upon effectiveness, allow us to register the 3,005,780 common limited partner units represented in the June private placement agreement and the 2,380,952 common limited partner units represented in the August private placement agreement.

On October 24, 2007, the board of directors of the General Partner declared a quarterly distribution of $0.55 per unit, payable on November 14, 2007 to unitholders of record on November 7, 2007. This distribution of $0.55 per unit exceeds the Fourth Target Distribution level (see Note 12 in our 2006 Form 10-K for discussion of distributions of available cash).

In September 2007, we received a distribution of $5.0 million from East Texas, for the third quarter of 2007. In October 2007, we received a distribution of $5.6 million from Discovery for the third quarter of 2007, and in July 2007, we received a distribution of $3.6 million from Discovery for the second quarter of 2007.

In conjunction with DCP Midstream, LLC s acquisition of MEG in August 2007, we acquired certain subsidiaries of MEG from DCP Midstream, LLC for aggregate consideration of approximately $165.8 million, subject to final closing adjustments. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments to date that include a liability of $9.0 million for net working capital and general and administrative charges. The subsidiaries of MEG own gathering, processing and compression assets in the Piceance and Powder River producing basins. The Piceance Basin assets consist of a 70 percent operating interest in the 31-mile Collbran Valley Gas Gathering system joint venture, which gathers and processes natural gas from over 20,000 dedicated acres in western Colorado. The processing facility capacity is currently being expanded from 60 MMcf/d to 120 MMcf/d. The other partners in the joint venture, Plains Exploration and Delta Petroleum, are also the producers on the system. The Powder River Basin assets include the 1,324-mile Douglas gas gathering system, which gathers approximately 30 MMcf/d of gas and covers more than 4,000 square miles in Wyoming. Also included in the transaction are the idle Painter Unit fractionator and Millis terminal, and associated NGL pipelines in southwest Wyoming. DCP Midstream, LLC will manage and operate these assets on our behalf. We financed this transaction with borrowings under our amended credit facility of $120.0 million, the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we sold 2,380,952 common units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. In connection with this common unit purchase agreement, we have a registration rights agreement that requires us to register the units within 90 days of the close of the private placement, and have filed a registration statement with the SEC. In addition, the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 180 days of the closing of the private placement. If the registration statement covering the common units is not declared effective by the SEC within 180 days of the closing of the private placement, then we will be liable to the purchasers for liquidated damages of 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for the first 60 days following the 180th day, increasing by an additional 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period.

In August 2007, our Omnibus Agreement with DCP Midstream, LLC was amended to increase the annual fee by $0.6 million for general and administrative expenses payable to DCP Midstream, LLC under the agreement to account for additional services provided to us and extend the term for all general and administrative expenses under the agreement through December 31, 2009. The Omnibus Agreement was further amended in August 2007 to include an additional annual fee of $1.6 million in connection with our acquisition of the MEG subsidiaries, described above.

In August 2007, we entered into interest rate swap agreements to convert $200.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. These interest rate swaps commenced on September 21, 2007, expire on June 21, 2012 and re-price prospectively approximately every 90 days. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation.

On July 1, 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC for aggregate consideration of approximately $271.3 million, consisting of approximately $243.7 million in cash, including $1.3 million for net working capital and other adjustments, the issuance of 620,404 common units to DCP Midstream, LLC valued at $27.0 million and the issuance of 12,661 general partner equivalent units valued at $0.6 million. We financed the cash portion of this transaction with borrowings of $245.9 million under our credit facility.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We will use the mark-to-market method of accounting for all commodity cash flow hedges beginning in July 2007. As a result, the remaining net loss of $2.5 million deferred in accumulated other comprehensive income as of September 30, 2007 will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings.

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 mitigated a portion of our anticipated commodity price risk associated with our gathering and processing arrangements through 2013 with natural gas and crude oil swaps. With these swaps, we have reduced our exposure to commodity price movements with respect to those volumes under these types of contractual arrangements for this period.

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We will continue to have direct commodity price risk associated with the remainder of our natural gas supply, and production of NGLs and condensate from our processing plants. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies in our 2006 Form 10-K and Item 3. Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report on Form 10-Q. 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 variability in natural gas prices. In the past, we have benefited from marketing activities and increased throughput related to atypical and significant differences in natural gas prices at various receipt and delivery points on our Pelico intrastate pipeline system. The market conditions causing the variability in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur.

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

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

In November 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC, and in July 2007 we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC, both in transactions among entities under common control. Accordingly, our financial information includes the historical results of our predecessors for each period presented. Prior to November 2006 and July 2007, our financial statements do not give effect to various items that affected our results of operations and liquidity following these acquisitions, including the indebtedness we incurred in conjunction with the closing of these acquisitions, which increased our interest expense from the interest expense reflected in our historical financial statements.

We completed pipeline integrity testing during 2006, resulting in increased operating costs on Seabreeze, one of our NGL transportation pipelines. The construction of Wilbreeze, an NGL transportation pipeline connecting a DCP Midstream, LLC gas processing plant to the Seabreeze pipeline, was completed in December 2006. The Black Lake pipeline is currently experiencing increased operating costs due to pipeline integrity testing that commenced in 2005 and is expected to continue into early 2008. We expect that our results of operations related to our equity interest in the Black Lake pipeline will benefit in 2008 from the completion of this pipeline integrity testing, although it is possible that the integrity testing will result in the need for pipeline repairs, in which case the operations of this pipeline may be interrupted while the repairs are being made. DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing, and up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of the pipeline integrity testing. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Any reimbursement of these expenses from DCP Midstream, LLC will be recognized by us as a capital contribution. Seabreeze pipeline integrity testing was completed in 2006 and reimbursements related to these repairs were not significant.

During 2006, we entered into agreements with ConocoPhillips, which expanded the gathering and transportation services between us. As a result of these agreements, 12 new wells were added during the nine months ended September 30, 2007, and 17 new wells were added to our system during 2006.

Discovery has signed definitive agreements with Chevron, Total and Statoil to construct an approximate 35-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. The Tahiti pipeline lateral expansion is expected to have a design capacity of approximately 200 MMcf/d. The pipeline was installed on the sea bed in February 2007. Chevron had scheduled initial throughput to begin in

mid-2008, but recently announced that it will face delays because of metallurgical problems discovered in the facility s mooring shackles. Chevron recently announced that it expects first production by the third quarter of 2009. Discovery s revenues from the Tahiti project are dependent on receiving throughput from Chevron. Therefore, delays Chevron experiences in bringing their production online will impact the initial timing of revenues for Discovery.

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 percentage-of-proceeds arrangements and fee-based arrangements, as described in Critical Accounting Policies and Estimates Revenue Recognition in our 2006 Form 10-K.

We have mitigated a portion of our currently anticipated natural gas and NGL commodity price risk associated with the percentage-of-proceeds arrangements through 2013 with natural gas and crude oil swaps. With these swaps, we expect our exposure to commodity price movements to be 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 mitigated a portion of our condensate price risk through 2013 with crude oil swaps. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies in our 2006 Form 10-K and Item 3. Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report on Form 10-Q.

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

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 Northern Louisiana system is derived primarily from natural gas wells located in five parishes in northern Louisiana, and in our Southern Oklahoma system is derived primarily from natural gas wells located in three counties in southern Oklahoma. The Pelico system receives natural gas produced in eastern Texas through its interconnect with other pipelines that transport natural gas from eastern Texas into western Louisiana. These areas have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. Our primary suppliers of natural gas to the Northern Louisiana and Southern Oklahoma systems represented approximately 65% of the 324 MMcf/d of natural gas supplied to this system in the nine months ended September 30, 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.

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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 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 occasionally will enter into financial derivatives to lock in price variability across the Pelico system to maximize the value of pipeline capacity. 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. The NGLs extracted by a third party that is processing natural gas in the Southern Oklahoma system are sold to third parties at market index prices.

Our operations within the Natural Gas Services segment include a 25% limited liability company interest in East Texas and a 40% limited liability company interest in Discovery. East Texas is engaged in the business of gathering, transporting, treating, compressing, processing, and fractionating natural gas and NGLs. Its operations, located near Carthage, Texas, include a natural gas processing complex with a total capacity of 780 million cubic feet per day. The facility is connected to an 845 mile gathering system, as well as third party gathering systems. The complex includes and is adjacent to the Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 billion cubic feet per day, acts as a key exchange point for the purchase and sale of residue gas. Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a 32,000 Bbl/d natural gas liquids fractionator plant near Paradis, Louisiana with a design capacity of 600 MMcf/d and approximately 173 miles of pipe, and several laterals expanding their presence in the Gulf.

Our operations within the Natural Gas Services segment also include the subsidiaries of MEG. The subsidiaries of MEG own gathering, processing and compression assets in the Piceance and Powder River producing basins. The Piceance Basin assets consist of a 70 percent operating interest in the 31-mile Collbran Valley Gas Gathering system joint venture, which gathers and processes natural gas from over 20,000 dedicated acres in western Colorado. The processing facility capacity is currently being expanded from 60 MMcf/d to 120 MMcf/d. The other partners in the joint venture, Plains Exploration and Delta Petroleum, are also the producers on the system. The Powder River Basin assets include the 1,324-mile Douglas gas gathering system, which gathers approximately 30 MMcf/d of gas and covers more than 4,000 square miles in Wyoming.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the Midwest and northeastern United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada, and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Midwest and the northeastern areas of the United States. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our primary suppliers of propane represented approximately 83% of our propane purchases in the nine months ended September 30, 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. We have entered into contractual arrangements with DCP Midstream, LLC that require DCP Midstream, LLC to pay us to transport the NGLs pursuant to a fee-based rate that is applied to the volumes transported. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines; rather, the shipper retains title and the associated commodity price risk. For the Seabreeze and Wilbreeze pipelines, we are responsible for any line loss or gain in NGLs. For the Black Lake pipeline, any line loss or gain in NGLs is allocated to the shipper. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the mixed NGLs from the natural gas. As a result, we have experienced periods in the past, and will likely experience periods in the future, in which higher natural gas prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets. In the markets we serve, our pipelines are the sole pipeline facility transporting NGLs from the supply source.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes; (2) gross margin, including segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) EBITDA; and (5) distributable cash flow. Gross margin, segment gross margin, EBITDA and distributable cash flow 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 for our Natural Gas Services segment and our NGL Logistics segment, and sales volumes for our Wholesale Propane Logistics segment as important factors affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of our natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by: (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines; and (2) our ability to compete for volumes from successful new wells in other areas. The throughput volumes of NGLs on our pipelines are substantially dependent upon the quantities of NGLs produced at our processing plants, as well as NGLs produced at other processing plants that have pipeline connections with our NGL pipelines. We regularly monitor producer activity in the areas we serve and our pipelines, and pursue opportunities to connect new supply to these pipelines.

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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 from our non-trading derivative activity. 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.

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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):

Reconciliation of Non-GAAP Measures	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Reconciliation of net income to gross margin:				
Net income	$ 7.5	$ 14.3	$ 24.1	$ 46.3
Add:				
Interest expense	8.1	2.9	16.5	8.1
Operating and maintenance expense	8.1	5.8	21.0	17.3
Depreciation and amortization expense	7.9	3.2	15.8	9.6
General and administrative expense	5.4	6.3	17.1	15.6
Non-controlling interest in income	0.3		0.3	
Less:				
Interest income	1.2	1.7	3.7	4.7
Earnings from equity method investments	10.8	8.2	23.6	24.0
Gross margin	$ 25.3	$ 22.6	$ 67.5	$ 68.2
Reconciliation of segment net income to segment gross margin:				
Natural Gas Services segment:				
Segment net income	$ 19.2	$ 23.1	$ 42.9	$ 61.5
Add:				
Operating and maintenance expense	5.4	3.1	12.6	10.1
Depreciation and amortization expense	7.4	2.7	14.1	8.2
Non-controlling interest in income	0.3		0.3	
Less: Earnings from equity method investments	10.3	8.2	22.6	23.9
Segment gross margin	$ 22.0	$ 20.7	$ 47.3	$ 55.9
Wholesale Propane Logistics segment:				
Segment net (loss) income	$ (0.9)	$ (1.7)	$ 8.0	$ 2.0
Add:				
Operating and maintenance expense	2.5	2.2	7.8	6.4
Depreciation and amortization expense	0.3	0.2	0.7	0.7
Segment gross margin	$ 1.9	$ 0.7	$ 16.5	$ 9.1
NGL Logistics segment:				
Segment net income	$ 1.5	$ 0.4	$ 3.1	$ 1.8
Add:				
Operating and maintenance expense	0.2	0.5	0.6	0.8
Depreciation and amortization expense	0.2	0.3	1.0	0.7
Less: Earnings from equity method investments	0.5		1.0	0.1
Segment gross margin	$ 1.4	$ 1.2	$ 3.7	$ 3.2

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. Our general and administrative expense was $5.4 million and $17.1 million, and $6.3 million and $15.6 million for the three and nine months ended September 30, 2007 and 2006, 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 for the initial assets under the agreement was fixed at such amount for 2006, which increased to $5.0 million for 2007; (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; (3) effective May 2007, includes an additional annual fee of $0.2 million related to the Southern Oklahoma asset acquisition; (4) effective July 2007, includes an additional annual fee of $0.2 million related to the acquisition of our 40% limited liability company interest in Discovery from DCP Midstream, LLC; (5) effective August 2007, includes an additional annual fee of $0.6 million to account for additional services provided to us; and (6) effective August 2007, includes an additional annual fee of $1.6 million related to our acquisition of certain subsidiaries of MEG from DCP Midstream, LLC. All of the fees under the Omnibus Agreement are subject to adjustment annually for changes in the Consumer Price Index. We expect our total general and administrative expenses under the Omnibus Agreement to be $7.9 million for 2007.

We incurred approximately $3.3 million and $11.5 million, and $5.1 million and $12.0 million, of other general and administrative expense during the three and nine months ended September 30, 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 $2.1 million and $5.6 million, and $1.2 million and $3.6 million, for the three and nine months ended September 30, 2007 and 2006, respectively, per the Omnibus Agreement, 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 Amended Credit Agreement) of not more than 5.75 to 1.0 through and including the quarter ended June 30, 2007 and 5.0 to 1.0 thereafter, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business, of not more than 5.50 to 1.0; and (2) an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination. Our EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA in the same manner.

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

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

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

We define distributable cash flow as net cash provided by operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities (see Liquidity and Capital Resources 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 mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing distributable cash flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices. Distributable cash flow is

used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner. Our distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate distributable cash flow in the same manner. The following table sets forth our reconciliation of certain non-GAAP measures ($ in millions):

Reconciliation of Non-GAAP Measures	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Reconciliation of net income to EBITDA:				
Net income	$ 7.5	$ 14.3	$ 24.1	$ 46.3
Interest income	(1.2)	(1.7)	(3.7)	(4.7)
Interest expense	8.1	2.9	16.5	8.1
Depreciation and amortization expense	7.9	3.2	15.8	9.6
EBITDA	$ 22.3	$ 18.7	$ 52.7	$ 59.3
Reconciliation of net cash provided by operating activities to EBITDA:				
Net cash provided by operating activities	$ 26.3	$ 2.2	$ 66.1	$ 40.2
Interest income	(1.2)	(1.7)	(3.7)	(4.7)
Interest expense	8.1	2.9	16.5	8.1
Earnings from equity method investments, net of distributions	2.2	(0.2)	(3.5)	4.5
Net changes in operating assets and liabilities	(13.1)	15.1	(23.1)	9.4
Other, net		0.4	0.4	1.8
EBITDA	$ 22.3	$ 18.7	$ 52.7	$ 59.3

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 and nine months ended September 30, 2007 are the same as those described in our 2006 Form 10-K.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Operating revenues:				
Natural Gas Services (a)	$ 118.6	$ 100.4	$ 306.3	$ 312.8
Wholesale Propane Logistics	66.7	60.8	293.7	271.3
NGL Logistics	3.3	1.6	6.9	4.2
Total operating revenues	188.6	162.8	606.9	588.3
Gross margin (b):				
Natural Gas Services	22.0	20.7	47.3	55.9
Wholesale Propane Logistics	1.9	0.7	16.5	9.1
NGL Logistics	1.4	1.2	3.7	3.2
Total gross margin	25.3	22.6	67.5	68.2
Operating and maintenance expense	8.1	5.8	21.0	17.3
General and administrative expense	5.4	6.3	17.1	15.6
Earnings from equity method investments (c)	10.8	8.2	23.6	24.0
Non-controlling interest in income	0.3		0.3	
EBITDA (d)	22.3	18.7	52.7	59.3
Depreciation and amortization expense	7.9	3.2	15.8	9.6
Interest income	1.2	1.7	3.7	4.7
Interest expense	8.1	2.9	16.5	8.1
Net income	$ 7.5	$ 14.3	$ 24.1	$ 46.3
Operating data:				
Natural gas throughput (MMcf/d) (c)	770	666	735	659
NGL gross production (Bbls/d) (c)	22,570	19,119	21,083	19,292
Propane sales volume (Bbls/d)	13,014	12,428	21,539	20,642
NGL pipelines throughput (Bbls/d) (c)	30,837	25,682	28,890	24,525

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

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

(c) Includes 45% of the throughput volumes and earnings of Black Lake, 25% of the throughput volumes and earnings of East Texas and 40% of the throughput volumes and earnings of Discovery. Earnings for Discovery and Black Lake include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the investments, for all periods presented.

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

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Three Months Ended September 30, 2007 vs. Three Months Ended September 30, 2006

Total Operating Revenues Total operating revenues increased $25.8 million, or 16%, to $188.6 million in 2007 from $162.8 million in 2006, primarily due to the following:

- $22.1 million increase attributable primarily to an increase in natural gas, NGL and condensate sales volumes, including increases as a result of the Southern Oklahoma and MEG acquisitions, offset by a decrease in commodity prices for our Natural Gas Services segment;
- $7.2 million increase attributable to higher propane sales volumes and prices for our Wholesale Propane Logistics segment;
- $1.9 million increase in transportation and processing services revenue, primarily attributable to an increase in volumes in our Natural Gas Services segment; and
- $1.5 million increase due to an increase in NGL throughput for our NGL Logistics segment; offset by
- $6.9 million decrease related to commodity hedging and non-trading derivative activity.

Gross Margin Gross margin increased $2.7 million, or 12%, to $25.3 million in 2007 from $22.6 million in 2006, primarily due to the following:

- $1.3 million increase for our Natural Gas Services segment primarily due to an increase in natural gas, NGL and condensate sales volumes, mainly as a result of the Southern Oklahoma and MEG acquisitions, offset by decreases related to commodity hedging and non-trading derivative activity and lower contractual fees charged to customers;
- $1.2 million increase for our Wholesale Propane Logistics segment due to higher sales volumes and higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, and non-cash lower of cost or market inventory adjustments recognized in 2006, partially offset by a decrease related to non-trading derivative activity; and
- $0.2 million increase for our NGL Logistics segment attributable to higher throughput volumes.

Operating and Maintenance Expense Operating and maintenance expense increased $2.3 million, or 40%, to $8.1 million in 2007 from $5.8 million in 2006, primarily as a result of the Southern Oklahoma and MEG acquisitions, and higher labor and benefits and pipeline integrity costs in our Natural Gas Services segment, and operating and maintenance expense at the Midland terminal, which became operational in May 2007 in our Wholesale Propane Logistics segment, offset by lower pipeline integrity costs on our Seabreeze pipeline, and lower equipment rental costs in our NGL Logistics segment.

General and Administrative Expense General and administrative expense decreased $0.9 million, or 14%, to $5.4 million in 2007 from $6.3 million in 2006, primarily as a result of higher costs in 2006 including due diligence, acquisition costs, and audit and legal fees, related to our acquisition of our wholesale propane logistics business.

Earnings from Equity Method Investments Earnings from equity method investments increased $2.6 million, or 32%, to $10.8 million in 2007 from $8.2 million in 2006, due to increased equity earnings of $0.9 million from East Texas, increased equity earnings of $1.2 million from Discovery, and increased equity earnings of $0.5 million from Black Lake.

Non-Controlling Interest in Income Non-controlling interest in income reduced income by $0.3 million in 2007, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased $4.7 million, to $7.9 million in 2007 from $3.2 million in 2006, primarily as a result of asset acquisitions.

Interest Expense Interest expense increased $5.2 million, to $8.1 million in 2007 from $2.9 million in 2006, primarily as a result of the financing of the 2007 acquisitions.

Nine Months Ended September 30, 2007 vs. Nine Months Ended September 30, 2006

Total Operating Revenues Total operating revenues increased $18.6 million, or 3%, to $606.9 million in 2007 from $588.3 million in 2006, primarily due to the following:

$23.9 million increase attributable to higher propane sales volumes and prices for our Wholesale Propane Logistics segment;

$9.0 million increase attributable primarily to an increase in natural gas, NGL and condensate sales volumes as a result of the Southern Oklahoma and MEG acquisitions, offset by a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation, as well as a decrease in commodity prices, in our Natural Gas Services segment;

$3.3 million increase in transportation and processing services revenue, primarily attributable to an increase in volumes in our Natural Gas Services segment; and

$2.1 million increase due to an increase in NGL sales volumes in our NGL Logistics segment; offset by

$19.7 million decrease related to commodity hedging and non-trading derivative activity.

Gross Margin Gross margin decreased $0.7 million, or 1%, to $67.5 million in 2007 from $68.2 million in 2006, primarily due to the following:

$8.6 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity hedging and non-trading derivative activity, and 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, offset by higher NGL and condensate production as a result of the Southern Oklahoma and MEG acquisitions; offset by

$7.4 million increase primarily as a result of higher sales volumes, higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, and non-cash lower of cost or market inventory adjustments recognized in 2006, partially offset by a decrease related to non-trading derivative activity for our Wholesale Propane Logistics segment; and

$0.5 million increase for our NGL Logistics segment primarily due to increased transportation revenue and volumes as a result of the addition of our Wilbreeze pipeline in December 2006.

Operating and Maintenance Expense Operating and maintenance expense increased $3.7 million, or 21%, to $21.0 million in 2007 from $17.3 million in 2006, primarily as a result of the Southern Oklahoma and MEG acquisitions, and higher labor and benefits and pipeline integrity costs in our Natural Gas Services segment, higher operating and maintenance expense at the new Midland terminal, which became operational in May 2007, and higher labor and benefit costs in our Wholesale Propane Logistics segment, offset by lower pipeline integrity costs on our Seabreeze pipeline in our NGL Logistics segment.

General and Administrative Expense General and administrative expense increased $1.5 million, or 10%, to $17.1 million in 2007 from $15.6 million in 2006, primarily as a result of increased due diligence and acquisition costs, audit and legal fees, and labor and benefit costs.

Earnings from Equity Method Investments Earnings from equity method investments decreased $0.4 million, or 2%, to $23.6 million in 2007 from $24.0 million in 2006 due to decreased equity earnings of $1.5 million from East Texas, offset by increased equity earnings of $0.2 million from Discovery and $0.9 million from Black Lake.

Non-Controlling Interest in Income Non-controlling interest in income reduced income by $0.3 million in 2007, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased $6.2 million, or 65%, to $15.8 million in 2007 from $9.6 million in 2006, primarily as a result of asset acquisitions.

Interest Expense Interest expense increased $8.4 million, to $16.5 million in 2007 from $8.1 million in 2006, primarily as a result of the financing of the 2007 acquisitions.

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Results of Operations Natural Gas Services Segment

This segment consists of our Northern Louisiana system, the Southern Oklahoma system acquired in May 2007, a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, and the Swap, acquired in July 2007, and certain subsidiaries of MEG, acquired in August 2007 ($ in millions, except operating data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 116.3	$ 94.5	$ 306.0	$ 295.6
Transportation and processing services	7.3	5.9	19.6	17.2
Losses from non-trading derivative activity (a)	(5.0)		(19.3)	
Total operating revenues	118.6	100.4	306.3	312.8
Purchases of natural gas and NGLs	96.6	79.7	259.0	256.9
Segment gross margin (b)	22.0	20.7	47.3	55.9
Operating and maintenance expense	5.4	3.1	12.6	10.1
Earnings from equity method investments (c)	10.3	8.2	22.6	23.9
Depreciation and amortization expense	7.4	2.7	14.1	8.2
Non-controlling interest in income	0.3		0.3	
Segment net income	$ 19.2	$ 23.1	$ 42.9	$ 61.5
Operating data:				
Natural gas throughput (MMcf/d) (c)	770	666	735	659
NGL gross production (Bbls/d) (c)	22,570	19,119	21,083	19,292

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

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

(c) Includes 25% of the throughput volumes and earnings of East Texas and 40% of the throughput volumes and earnings of Discovery, and the amortization of the net difference between the carrying amount of Discovery and the underlying equity of Discovery, for all periods presented.

Three Months Ended September 30, 2007 vs. Three Months Ended September 30, 2006

Total Operating Revenues Total operating revenues increased $18.2 million, or 18%, to $118.6 million in 2007 from $100.4 million in 2006, primarily due to the following:

- $25.2 million increase primarily attributable to higher natural gas, NGL and condensate sales volumes, primarily as a result of the Southern Oklahoma and MEG acquisitions; and

- $1.4 million increase in transportation and processing services revenue primarily as a result of the Southern Oklahoma and MEG acquisitions; offset by

- $5.3 million decrease related to commodity hedging and non-trading derivative activity; and

- $3.1 million decrease attributable to a decrease in commodity prices.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased $16.9 million, or 21%, to $96.6 million in 2007 from $79.7 million in 2006, primarily due to increased natural gas purchase volumes, primarily as a result of the Southern Oklahoma and MEG acquisitions, offset by lower costs of raw natural gas supply, driven by lower commodity prices.

Segment Gross Margin Segment gross margin increased $1.3 million, or 6%, to $22.0 million in 2007 from $20.7 million in 2006, primarily as a result of the following:

- $6.8 million increase primarily attributable to an increase in natural gas, NGL and condensate sales volumes, mainly as a result of the Southern Oklahoma and MEG acquisitions; offset by

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- $5.3 million decrease related to commodity hedging and non-trading derivative activity; and

- $0.2 million decrease primarily attributable to lower contractual fees charged to customers.

Operating and Maintenance Expense Operating and maintenance expense increased $2.3 million, or 74%, to $5.4 million in 2007 from $3.1 million in 2006, primarily as a result of the Southern Oklahoma and MEG acquisitions, and higher labor and benefits and pipeline integrity costs.

NGL production during 2007 increased 3,451 Bbls/d, or 18%, to 22,570 Bbls/d from 19,119 Bbls/d in 2006, and natural gas transported and/or processed during 2007 increased 104 MMcf/d, or 16%, to 770 MMcf/d from 666 MMcf/d in 2006. These increases were due primarily to an increase in volumes from Discovery, as well as an increase in volumes from the Southern Oklahoma and MEG acquisitions.

Earnings from Equity Method Investments Earnings from equity method investments increased $2.1 million, or 26%, to $10.3 million in 2007 from $8.2 million in 2006, due to an increase in equity earnings of $1.2 million from Discovery and an increase in equity earnings of $0.9 million from East Texas. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

- Increased equity earnings from East Texas were the result of an increase in East Texas net income of $3.7 million, or 32%, due primarily to a $5.8 million increase as a result of higher commodity prices, and a decrease in operating and general and administrative expenses of $0.3 million, offset by a $1.5 million decrease due to a decline in natural gas volumes and a $0.9 million decrease due to decreased fee-based revenue.

- Increased equity earnings from Discovery were the result of an increase in Discovery s net income of $3.0 million, or 30%, due primarily to $6.9 million higher NGL margins due to higher NGL sales volumes, partially offset by $1.6 million lower fee-based gathering, processing and fractionation revenues, $0.6 million lower transportation revenues and $1.9 million higher operating and maintenance expense.

Depreciation and Amortization Expense Depreciation and amortization expense increased $4.7 million, to $7.4 million in 2007 from $2.7 million in 2006, primarily as a result of the Southern Oklahoma and MEG acquisitions.

Non-Controlling Interest in Income Non-controlling interest in income reduced income by $0.3 million in 2007, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

Nine Months Ended September 30, 2007 vs. Nine Months Ended September 30, 2006

Total Operating Revenues Total operating revenues decreased $6.5 million, or 2%, to $306.3 million in 2007 from $312.8 million in 2006, primarily due to the following:

- $17.9 million decrease related to commodity hedging and non-trading derivative activity; and

- $10.5 million decrease attributable to a decrease in commodity prices; offset by

- $19.5 million increase attributable to an increase in natural gas, NGL and condensate sales volumes, primarily as a result of the Southern Oklahoma and MEG asset acquisitions, partially offset by a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation; and

$2.4 million increase in transportation and processing services revenue primarily attributable to an increase in natural gas throughput.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased $2.1 million, or 1%, to $259.0 million in 2007 from $256.9 million in 2006, primarily due to increased natural gas purchase volumes primarily as a result of the Southern Oklahoma and MEG asset acquisitions, offset by lower natural gas prices and decreased natural gas purchase volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation.

Segment Gross Margin Segment gross margin decreased $8.6 million, or 15%, to $47.3 million in 2007 from $55.9 million in 2006, primarily as a result of the following:

$17.9 million decrease related to commodity hedging and non-trading derivative activity;

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

$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; offset by

$12.4 million increase primarily attributable to an increase in NGL and condensate production, partially as a result of the Southern Oklahoma asset acquisition, and an increase in natural gas throughput volumes; and

$0.3 million increase primarily attributable to higher contractual fees charged to customers.

Operating and Maintenance Expense Operating and maintenance expense increased $2.5 million, or 25%, to $12.6 million in 2007 from $10.1 million in 2006, primarily as a result of the Southern Oklahoma and MEG acquisitions, and higher labor and benefits and pipeline integrity costs.

NGL production during 2007 increased 1,791 Bbls/d, or 9%, to 21,083 Bbls/d from 19,292 Bbls/d in 2006, and natural gas transported and/or processed during 2007 increased 76 MMcf/d, or 12%, to 735 MMcf/d from 659 MMcf/d in 2006. These increases were due primarily to increased volumes from Discovery, as well as an increase in volumes from the Southern Oklahoma and MEG acquisitions.

Earnings from Equity Method Investments Earnings from equity method investments decreased $1.3 million, or 5%, to $22.6 million in 2007 from $23.9 million in 2006, due to a decrease in equity earnings of $1.5 million from East Texas, offset by an increase in equity earnings of $0.2 million from Discovery. Decreased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

Decreased equity earnings from East Texas were the result of a decrease in East Texas s net income of $5.9 million, or 15%, due primarily to a $3.6 million decrease due to a decline in natural gas volumes, a $3.7 million decrease due to decreased fee-based revenue, and an increase in operating and maintenance expenses of $2.3 million, primarily due to increased contract services, materials and supplies, and labor an benefits, and increased general and administrative expenses of $2.1 million, primarily due to higher allocated costs from DCP Midstream, LLC, offset by a $5.8 million increase as a result of higher commodity prices.

Increased equity earnings from Discovery were the result of an increase in Discovery s net income of $0.7 million, or 3%, due primarily to $20.9 million higher NGL margins on higher NGL sales volumes largely offset by $11.2 million lower fee-based transportation, gathering, processing and fractionation revenues from the absences of the 2006 Tennessee Gas Pipeline, or TGP, and Texas Eastern Transmission Company, or TETCO, open season agreements and $7.3 million higher operating and maintenance expense and $1.3 million higher other expense. The open seasons provided outlets for natural gas that was stranded following damage to third-party facilities during hurricanes Katrina and Rita. TGP s open season contract came to an end in early 2006.

Depreciation and Amortization Expense Depreciation and amortization expense increased $5.9 million, to $14.1 million in 2007 from $8.2 million in 2006, primarily as a result of the Southern Oklahoma and MEG acquisitions.

Non-Controlling Interest in Income Non-controlling interest in income reduced income by $0.3 million in 2007, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

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Results of Operations Wholesale Propane Logistics Segment

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Operating revenues:				
Sales of propane	$ 67.5	$ 60.3	$ 295.2	$ 271.3
Transportation and processing services	0.3		0.3	
(Losses) gains from non-trading derivative activity	(1.1)	0.5	(1.8)	
Total operating revenues	66.7	60.8	293.7	271.3
Purchases of propane	64.8	60.1	277.2	262.2
Segment gross margin (a)	1.9	0.7	16.5	9.1
Operating and maintenance expense	2.5	2.2	7.8	6.4
Depreciation and amortization expense	0.3	0.2	0.7	0.7
Segment net (loss) income	$ (0.9)	$ (1.7)	$ 8.0	$ 2.0
Operating data:				
Propane sales volume (Bbls/d)	13,014	12,428	21,539	20,642

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

Three Months Ended September 30, 2007 vs. Three Months Ended September 30, 2006

Total Operating Revenues Total operating revenues increased $5.9 million, or 10%, to $66.7 million in 2007 from $60.8 million in 2006, primarily due to the following:

$4.4 million increase attributable to higher propane prices;

$2.8 million increase attributable to higher propane sales volumes as a result of milder weather in the northeastern United States in 2006 and the completion of the new Midland terminal in May 2007; and

$0.3 million increase in transportation and processing services; offset by

$1.6 million decrease related to non-trading derivative activity.

Purchases of Propane Purchases of propane increased $4.7 million, or 8%, to $64.8 million in 2007 from $60.1 million 2006, primarily due to increased purchased volumes and prices, primarily due to milder weather in the northeastern United States in 2006, as well as increased purchased volumes due to the completion of the new Midland terminal in May 2007.

Segment Gross Margin Segment gross margin increased $1.2 million, to $1.9 million in 2007 from $0.7 million in 2006, primarily as a result of higher sales volumes and higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, and non-cash lower of cost or market inventory adjustments recognized in 2006, partially offset by a decrease related to non-trading derivative activity.

Operating and Maintenance Expense Operating and maintenance expense increased $0.3 million, or 14%, to $2.5 million in 2007 from $2.2 million in 2006, primarily due to operating and maintenance expense at the Midland terminal, which became operational in May 2007.

Propane sales increased 586 Bbls/d, or 5%, to 13,014 Bbls/d in 2007 from 12,428 Bbls/d in 2006, due primarily to milder weather in the northeastern United States in 2006.

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Nine Months Ended September 30, 2007 vs. Nine Months Ended September 30, 2006

Total Operating Revenues Total operating revenues increased $22.4 million, or 8%, to $293.7 million in 2007 from $271.3 million in 2006, primarily due to the following:

- $13.2 million increase attributable to higher propane sales volumes as a result of milder weather in the northeastern United States in 2006 and the completion of the new Midland terminal in May 2007;

- $10.7 million increase attributable to higher propane prices; and

- $0.3 million increase in transportation and processing services; offset by

- $1.8 million decrease related to non-trading derivative activity.

Purchases of Propane Purchases of propane increased $15.0 million, or 6%, to $277.2 million in 2007 from $262.2 million in 2006, primarily due to increased purchased volumes and prices, primarily due to milder weather in the northeastern United States in 2006, and the completion of the new Midland terminal in May 2007, offset by non-cash lower of cost or market inventory adjustments recognized in 2006.

Segment Gross Margin Segment gross margin increased $7.4 million, or 81%, to $16.5 million in 2007 from $9.1 million in 2006, primarily as a result of higher sales volumes, higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, and non-cash lower of cost or market inventory adjustments recognized in 2006, partially offset by a decrease related to non-trading derivative activity.

Operating and Maintenance Expense Operating and maintenance expense increased $1.4 million, or 22%, to $7.8 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 became operational in May 2007, and higher labor and benefit costs.

Propane sales increased 897 Bbls/d, or 4%, to 21,539 Bbls/d in 2007 from 20,642 Bbls/d in 2006, due primarily to milder weather in the northeastern United States in 2006 and the completion of the Midland terminal in May 2007.

Results of Operations NGL Logistics Segment

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Operating revenues:				
Sales of NGLs	$ 2.0	$ 0.5	$ 3.1	$ 1.0
Transportation and processing services	1.3	1.1	3.8	3.2
Total operating revenues	3.3	1.6	6.9	4.2
Purchases of NGLs	1.9	0.4	3.2	1.0
Segment gross margin (a)	1.4	1.2	3.7	3.2
Operating and maintenance expense	0.2	0.5	0.6	0.8

Earnings from equity method investment (b)	0.5		1.0	0.1
Depreciation and amortization expense	0.2	0.3	1.0	0.7
Segment net income	$ 1.5	$ 0.4	$ 3.1	$ 1.8
Operating data:				
NGL pipelines throughput (Bbls/d) (b)	30,837	25,682	28,890	24,525

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

(b) Includes 45% of the throughput volumes and earnings of Black Lake and the amortization of the net difference between the carrying amount of Black Lake and the underlying equity of Black Lake, for all periods presented.

Three Months Ended September 30, 2007 vs. Three Months Ended September 30, 2006

Total Operating Revenues Total operating revenues increased $1.7 million, to $3.3 million in 2007 from $1.6 million in 2006, primarily due to an increase in volumes.

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 December 2006.

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Purchases of NGLs Purchases of NGLs increased $1.5 million, to $1.9 million in 2007 from $0.4 million in 2006, primarily due to an increase in volumes.

Segment Gross Margin Segment gross margin remained relatively constant in 2007 and 2006, but was impacted by higher throughput volumes in 2007.

Operating and Maintenance Expense Operating and maintenance expense decreased $0.3 million to $0.2 million in 2007 from $0.5 million in 2006, primarily due to lower pipeline integrity repairs on our Seabreeze pipeline, and lower equipment rental costs.

Earnings from Equity Method Investments Earnings from equity method investments increased to $0.5 million in 2007 from $0 in 2006. This increase was as a result of higher Black Lake transport volumes.

Nine Months Ended September 30, 2007 vs. Nine Months Ended September 30, 2006

Total Operating Revenues Total operating revenues increased $2.7 million, or 64%, to $6.9 million in 2007 from $4.2 million in 2006, primarily due to an increase in volumes.

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 December 2006.

Purchases of NGLs Purchases of NGLs increased $2.2 million to $3.2 million in 2007 from $1.0 million 2006, primarily due to an increase in volumes.

Segment Gross Margin Segment gross margin increased $0.5 million, or 16%, to $3.7 million in 2007 from $3.2 million in 2006, primarily due to increased transportation revenue and volumes as a result of the addition of our Wilbreeze pipeline in December 2006.

Operating and Maintenance Expense Operating and maintenance expense decreased $0.2 million, to $0.6 million in 2007 from $0.8 million in 2006, primarily due to lower pipeline integrity costs on our Seabreeze pipeline.

Earnings from Equity Method Investments Earnings from equity method investments increased to $1.0 million in 2007 from $0.1 million in 2006. This increase was as a result of higher Black Lake transport volumes and reduced operating expenses.

Liquidity and Capital Resources

Sources of liquidity for our wholesale propane logistics business prior to our acquisition of this business from DCP Midstream, LLC included cash generated from operations and funding from DCP Midstream, LLC. Its 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 East Texas, Discovery and Black Lake;
- borrowings under our revolving credit facility;
- cash realized from the liquidation of securities that may be 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 derivative program, as well as any future derivatives we enter into, may require us to post collateral depending on commodity price movements.

The counterparties to each of our swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds. As of November 8, 2007, we have posted collateral with certain counterparties of approximately $9.0 million. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. As the swap contracts settle and the notional volume outstanding decreases, a higher forward curve price is required to reach the collateral threshold. Predetermined collateral thresholds for hedges guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC s credit rating and the thresholds would be reduced to $0 in the event DCP Midstream, LLC s credit rating were to fall below investment grade. DCP Midstream, LLC has provided guarantees to support certain natural gas, NGL and condensate hedging contracts through 2010 that were executed prior to our initial public offering.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with our gathering and processing arrangements through 2013 with natural gas and crude oil swaps. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies in our 2006 Form 10-K and Item 3. Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report on Form 10-Q.

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

We had working capital of $34.0 million and $33.1 million as of September 30, 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 or used in operating, investing and financing activities for the nine months ended September 30, 2007 and 2006 were as follows ($ in millions):

	Nine Months Ended September 30,	
	2007	**2006**
Net cash provided by operating activities	$ 66.1	$ 40.2
Net cash used in investing activities	$ (499.1)	$ (28.8)
Net cash provided by (used in) financing activities	$ 446.4	$ (38.5)

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.

We received cash distributions from equity method investments of $27.1 million and $19.5 million, during the nine months ended September 30, 2007 and 2006, respectively. Distributions exceeded earnings by $3.5 million for the nine months ended September 30, 2007. Earnings exceeded distributions by $4.5 million for the nine months ended September 30, 2006.

Net Cash Used in Investing Activities Net cash used in investing activities during the nine months ended September 30, 2007, was primarily used for: (1) acquisition of the MEG subsidiaries of $142.0 million; (2) asset acquisitions of $191.3 million; (3) capital expenditures of $11.6 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities; and (4) investments in Discovery of $3.9 million and East Texas of $0.4 million; which were partially offset by (5) net sales of available-for-sale securities of $3.3 million. Net cash used in investing activities during the nine months ended September 30, 2006 was primarily used for capital expenditures, investments in Discovery and net purchases of available-for-sale securities.

Net Cash Provided by (Used in) Financing Activities Net cash provided by financing activities during the nine months ended September 30, 2007, was comprised of borrowings of $569.0 million and the issuance of common units for $228.5 million, net of offering costs, offset by repayment of debt of $207.0 million, the excess of purchase price over the acquired assets attributable to a payment related to our acquisition of our wholesale propane logistics business of $9.9 million, distributions to our unitholders of $28.8 million, and net change in advances from DCP Midstream, LLC of $14.6 million. Net cash used in financing activities during the nine months ended September 30, 2006 was primarily comprised of repayments of debt, changes in parent advances and distributions to our unitholders.

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

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 10 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. Our expansion capital expenditures in this segment may include constructing new gathering lines and compression facilities to connect new wells to our Southern Oklahoma, Colorado and Wyoming systems. In our Wholesale Propane Logistics and NGL Logistics segments, our capital expenditures may include the construction of new propane terminals and NGL pipelines that may 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 nine months ended September 30, 2007, our capital expenditures totaled $11.6 million, including maintenance capital expenditures of $1.9 million and expansion capital expenditures of $9.7 million. We have an agreement with certain producers whereby these producers will reimburse us for certain capital projects completed by us. During the nine months ended September 30, 2007, the changes in receivables and collections of maintenance capital expenditures, from DCP Midstream, LLC and producers, were approximately $0.2 million. As a result, our total maintenance capital expenditures net of reimbursements were approximately $1.7 million for the nine months ended September 30, 2007. During the nine months ended September 30, 2006, our capital expenditures totaled $18.4 million, including maintenance capital expenditures of $2.1 million and expansion capital expenditures of $16.3 million.

Maintenance capital expenditures in 2007 were lower than 2006 as a result of a higher number of well connects in the first nine months of 2006 versus 2007. Annual expansion capital and acquisition expenditures in 2007 are expected to increase as a result of the acquisitions detailed above in Recent Events. These anticipated increases in capital expenditures in 2007 will be 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 Midland propane terminal in 2006, for which expansion capital expenditures were approximately $9.2 million in 2006. 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 $28.8 million during the nine months ended September 30, 2007, as compared to $14.7 million for the same period in 2006. The distributions paid during 2006 included the pro rata portion of our Minimum Quarterly Distribution of $0.35 per unit for the period December 7, 2005, the closing of our initial public offering, through December 31, 2005. We intend to make quarterly distribution payments to our unitholders to the extent we have sufficient cash from operations after the establishment of reserves.

Description of Amended Credit Agreement On June 21, 2007, we entered into an Amended and Restated Credit Agreement, or the Amended Credit Agreement, which amended our existing Credit Agreement. This new 5-year Amended Credit Agreement consists of a $600.0 million revolving credit facility and a $250.0 million term loan facility, and matures on June 21, 2012. The

amendment also improved pricing and certain other terms or conditions of the Credit Agreement. On June 21, 2007, we borrowed $259.0 million from our revolving credit facility under the Amended Credit Agreement to replace existing borrowings under the existing Credit Agreement, of which $10.0 million was repaid in June 2007. In July 2007 we borrowed $246.0 million from our revolving credit facility to finance the acquisition of our interests in East Texas and Discovery. In August 2007 we borrowed $100.0 million from our term loan facility and $35.0 million from our revolving credit facility to finance the MEG acquisition and for general corporate purposes. As of September 30, 2007, the outstanding balance on the revolving credit facility was $530.0 million and the outstanding balance on the term loan facility was $100.0 million.

Our obligations under the revolving credit facility are unsecured, and the term loan facility is secured at all times by high-grade securities, which are classified as restricted investments in the accompanying condensed consolidated balance sheets, in an amount equal to or greater than the outstanding principal amount of the term loan. When outstanding, 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. The unused portion of the revolving credit facility may be used for letters of credit. At both September 30, 2007 and December 31, 2006 there were outstanding letters of credit of $0.2 million.

We have the option of increasing the size of the revolving credit facility to $1.0 billion with the consent of the issuing lenders.

We may prepay all loans at any time without penalty, subject to the reimbursement of lender breakage costs in the case of prepayment of London Interbank Offered Rate, or LIBOR, borrowings. Indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank s prime rate or the federal funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our leverage level or credit rating. As of September 30, 2007, the weighted-average interest rate on our revolving credit facility was 5.74% per annum. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to either: (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank s prime rate or the federal funds rate plus 0.50%. As of September 30, 2007, the interest rate on our term loan facility was 5.23%.

The Amended Credit Agreement prohibits us from making distributions of Available Cash to unitholders if any default or event of default (as defined in the Amended Credit Agreement) exists. The Amended Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended Credit Agreement) of not more than 5.75 to 1.0 through and including the quarter ended June 30, 2007 and 5.0 to 1.0 thereafter, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.50 to 1.0. The Amended Credit Agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loan

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

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

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Total Contractual Cash Obligations and Off-Balance Sheet Arrangements

A summary of our total contractual cash obligations as of September 30, 2007, is as follows ($ in millions):

		Payments Due by Period			
	Total	**Remainder of 2007**	**2008-2009**	**2010-2011**	**2012 and Thereafter**
Long-term debt (a)	$ 705.8	$ 4.5	$ 36.2	$ 29.4	$ 635.7
Operating lease obligations	41.3	3.0	15.7	11.5	11.1
Purchase obligations (b)	0.1	0.1			
Other long-term liabilities (c)	3.0	0.1			2.9
Total	$ 750.2	$ 7.7	$ 51.9	$ 40.9	$ 649.7

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

(b) Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized on the condensed consolidated balance sheet. Purchase obligations also exclude current and long-term unrealized losses on non-trading derivative and hedging instruments included on the condensed consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities. 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 $2.9 million of asset retirement obligations and $0.1 million of environmental reserves recognized on the September 30, 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.

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

Interest Rate Risk

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

We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. On August 1, 2007, we entered into interest rate swap agreements, which commenced on September 21, 2007, expire on June 21, 2012 and re-price prospectively approximately every 90 days, to mitigate the variable interest rate on $200.0 million of the indebtedness outstanding under our revolving credit facility. During 2006, we entered into interest rate swap agreements to mitigate 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. At September 30, 2007, the effective weighted-average interest rate on our $530 million of outstanding revolver debt was 5.53%, taking into account the $325 million of indebtedness with designated interest rate swaps.

Based on the annualized unhedged borrowings under our credit facility of $305.0 million as of September 30, 2007, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $1.5 million annualized increase or decrease in interest expense.

Commodity Price Risk

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

As of September 30, 2007, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk through 2013 with natural gas and crude oil non-trading derivatives. In addition to our previously existing non-trading derivative positions, in the second quarter of 2007 we entered into the following non-trading derivative positions.

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In May 2007, we executed a series of financial derivatives to mitigate a portion of the commodity price exposure associated with the Southern Oklahoma asset acquisition. We entered into natural gas swap contracts for 1,500 MMBtu/d at $7.54 per MMBtu and crude oil swap contracts for 650 Bls/d at $67.60 per Bbl for a term from June 2007 through December 2013.

In June 2007, we executed a series of financial derivatives to mitigate a portion of the commodity price exposure associated with our Northern Louisiana system assets. We entered into crude oil swap contracts for 250 Bbls/d at $71.35/Bbl for 2011, 600 Bbls/d at $71.00/Bbl for 2012 and 600 Bbls/d at $71.20/Bbl for 2013.

In July 2007, we acquired the Swap, a financial derivative, entered into by DCP Midstream, LLC, to mitigate a portion of the commodity price exposure associated with the acquisition on July 1, 2007 of a 25% limited liability company interest in East Texas and a 40% limited liability company interest in Discovery. This contract consists of crude oil swaps at $66.72/Bbl for 1,100 Bbls/d through 2007, 1,000 Bbls/d through 2008, 925 Bbls/d through 2009, 900 Bbls/d through 2010, 875 Bbls/d through 2011 and 850 Bbls/d through 2012.

In August 2007, in conjunction with our acquisition of certain MEG subsidiaries we acquired a series of financial derivatives to mitigate a portion of the commodity price exposure associated with our Powder River Basin assets. These derivatives consist of natural gas swap contracts for 3,460 MMBtu/d through December 2007 and 3,320 MMBtu/d through June 2008, at an average price of $6.85 per MMBtu, and NGL swap contracts for 14,620 gallons per day through December 2007 and 14,310 gallons per day through June 2008, at an average price of $0.97 per gallon.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We will use the mark-to-market method of accounting for all commodity cash flow hedges, which is expected to significantly increase the volatility of our results of operations as we will recognize, in current earnings, all non-cash gains and losses from the mark-to-market on non-trading derivative activity. We estimate the following non-cash sensitivities related to the mark-to-market on our commodity derivatives:

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income)
Natural gas prices	$ 1.00	MMBtu	$ 7.2
NGL prices	$ 0.10	Gallon	$ 0.4
Crude oil prices	$ 5.00	Barrel	$ 20.5

These sensitivities include the effect of all non-cash gains and losses from the mark-to-market on non-trading derivative activities.

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

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income
Natural gas prices	$ 1.00	MMBtu	$ 0.7
NGL prices	$ 0.10	Gallon	$ 3.0
Crude oil prices	$ 5.00	Barrel	$ 0.2

Based on our current contract mix, we believe that during the remainder of 2007 we will have a long position in natural gas, NGLs and condensate, and will be sensitive to changes in commodity prices.

These sensitivities include the effect of settlements on our financial derivatives. 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.

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

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

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 nine months ended September 30, 2007 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

The information required for this item is provided in Note 14, 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 partial ownership interests in a number of joint venture legal entities, including Discovery, East Texas and Black Lake, which could adversely affect our ability to operate and control these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to you.

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

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

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

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

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

Discovery s interstate tariff rates are subject to review and possible adjustment by federal regulators, which could have a material adverse effect on our business and operating results. Moreover, because Discovery is a non-corporate entity, it may be disadvantaged in calculating its cost-of-service for rate-making purposes.

The FERC, pursuant to the Natural Gas Act, regulates many aspects of Discovery s interstate pipeline transportation service, including the rates that Discovery is permitted to charge for such service. Under the Natural Gas Act, interstate transportation rates must be just and reasonable and not unduly discriminatory. If the FERC fails to permit tariff rate increases requested by Discovery, or if the FERC lowers the tariff rates Discovery is permitted to charge its customers, on its own initiative, or as a result of challenges raised by Discovery s customers or third parties, Discovery s tariff rates may be insufficient to recover the full cost of providing interstate transportation service. The FERC could require refund by Discovery of certain amounts exceeding those rates determined by FERC to be lawful. An adverse decision by the FERC in approving Discovery s regulated rates could adversely affect our cash flows. Although the FERC generally does not regulate the natural gas gathering operations of Discovery under the Natural Gas Act, federal regulation influences the parties that gather natural gas on the Discovery gas gathering system.

Discovery s maximum regulated rate for mainline transportation is scheduled to decrease in 2008. At that time, Discovery may be required to reduce its mainline transportation rate on all of its contracts that have rates above the new maximum rate. This could reduce the revenues generated by Discovery. Discovery may elect to file a rate case with the FERC seeking to alter this scheduled maximum rate reduction. However, if filed, a rate case may not be successful in preventing all or part of the rate reduction. If Discovery makes such a filing, it is possible that other aspects of Discovery s cost-of-service and rate design could be reviewed, which could result in additional reductions to its regulated rates.

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

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

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

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal income tax on our taxable income at the corporate tax rate, distributions to you would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as an investment company would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units. For a discussion of the federal income tax implications if we were treated as a corporation in any taxable year, please read Material Tax Consequences Partnership Status.

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

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

In addition to federal income taxes, the unitholder may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. The unitholder may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, the unitholder may be subject to penalties for failure to comply with those requirements. We own assets and conduct business in the states of Colorado, Wyoming, Oklahoma, Louisiana, Texas, Arkansas, Pennsylvania, New York, Vermont, Massachusetts, Rhode Island, Maine, Connecticut, Indiana, Kentucky, Maryland, New Hampshire, Ohio, Virginia, West Virginia and Tennessee. Each of these states, other than Texas, currently imposes a personal income tax as well as an income tax on corporations and other entities. Texas imposes a franchise tax (which is based in part on net income) on corporations and limited liability companies. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in the common units. We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Please read Material Tax Consequences Disposition of Common Units Allocations Between Transferors and Transferees.

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

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

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

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

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

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

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

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 until August 2007 when such units were distributed to DCP Midstream, GP, LP for director compensation purposes.

In June 2007, we entered into a private placement agreement with a group of institutional investors for $130.0 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $128.5 million, net of offering costs. In connection with this private placement agreement, we entered into a registration rights agreement with institutional investors that requires us to register the units by the earlier of within 120 days of the close of the private placement or when a registration statement is filed to register the units issued in connection with the MEG acquisition, and we have met the requirement to file a registration statement with the Securities and Exchange Commission. In addition the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 210 days of the closing of the private placement, or we will be liable to the institutional investors for liquidated damages of 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for the first 60 days following the 210th day, increasing by an additional 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period.

In August 2007, we sold 2,380,952 common units in a private placement, pursuant to a common unit purchase agreement with private owners of Momentum Energy Group, Inc. or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. In connection with this common unit purchase agreement, we have a registration rights agreement that requires us to register the units within 90 days of the close of the private placement, and have met the requirement to file a registration statement with the Securities and Exchange Commission. In addition, the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 180 days of the closing of the private

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placement. If the registration statement covering the common units is not declared effective by the SEC within 180 days of the closing of the private placement, then we will be liable to the purchasers for liquidated damages of 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for the first 60 days following the 180th day, increasing by an additional 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period.

Item 6. Exhibits *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	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.

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 November 9, 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)

EXHIBIT INDEX

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