DCP Midstream Partners, LP
Form 10-Q
November 10, 2008
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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, 2008

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, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Smaller reporting company ¨

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 3, 2008, there were outstanding 24,661,754 common limited partner units and 3,571,429 subordinated units.

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DCP MIDSTREAM PARTNERS, LP

FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2008

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

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in Item 1A. Risk Factors in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2007, as well as the following risks and uncertainties:

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

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

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

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

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

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

- the creditworthiness of counterparties to our transactions;

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

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

- industry changes, including the impact of consolidations, increased delivery of liquefied natural gas to the United States, alternative energy sources, technological advances and changes in competition;

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

- general economic, market and business conditions.

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

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PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2008	December 31, 2007
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23.5	$ 24.5
Short-term investments	2.5	1.3
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.7 million and $1.2 million, respectively	41.3	81.7
Affiliates	46.8	52.1
Inventories	31.8	37.3
Unrealized gains on derivative instruments	3.3	3.1
Other	0.3	18.5
Total current assets	149.5	218.5
Restricted investments	221.1	100.5
Property, plant and equipment, net	496.9	500.7
Goodwill	82.1	80.2
Intangible assets, net	28.3	29.7
Equity method investments	181.8	187.2
Unrealized gains on derivative instruments	1.5	2.7
Other long-term assets	1.1	1.2
Total assets	$ 1,162.3	$ 1,120.7
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 52.7	$ 110.2
Affiliates	17.8	55.6
Unrealized losses on derivative instruments	36.1	30.9
Accrued interest payable	1.6	1.6
Other	18.6	21.3
Total current liabilities	126.8	219.6
Long-term debt	655.0	630.0
Unrealized losses on derivative instruments	108.9	70.0
Other long-term liabilities	9.1	5.8
Total liabilities	899.8	925.4
Non-controlling interests	29.1	26.9

Commitments and contingent liabilities		
Partners equity:		
Common unitholders (24,661,754 and 16,840,326 units issued and outstanding, respectively)	324.5	308.8
Subordinated unitholders (3,571,429 and 7,142,857 convertible units issued and outstanding, respectively)	(69.3)	(120.1)
General partner interest	(6.4)	(5.4)
Accumulated other comprehensive loss	(15.4)	(14.9)
Total partners equity	233.4	168.4
Total liabilities and partners equity	$ 1,162.3	$ 1,120.7

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, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 137.9	$ 112.2	$ 551.7	$ 414.1
Sales of natural gas, propane, NGLs and condensate to affiliates	133.3	73.6	400.7	190.2
Transportation, processing and other	9.4	4.5	18.0	11.4
Transportation, processing and other to affiliates	4.2	4.4	21.7	12.3
Gains (losses) from commodity derivative activity, net	143.4	(4.7)	(79.2)	(19.2)
Losses from commodity derivative activity, net affiliates	(1.4)	(1.4)	(2.5)	(1.9)
Total operating revenues	426.8	188.6	910.4	606.9
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	186.2	131.3	673.0	423.9
Purchases of natural gas, propane and NGLs from affiliates	63.2	32.0	193.9	115.5
Operating and maintenance expense	10.2	8.1	31.8	21.0
Depreciation and amortization expense	8.8	7.9	26.3	15.8
General and administrative expense	3.2	2.9	8.2	9.9
General and administrative expense affiliates	2.8	2.5	8.6	7.2
Other			(1.5)	
Total operating costs and expenses	274.4	184.7	940.3	593.3
Operating income (loss)	152.4	3.9	(29.9)	13.6
Interest income	1.7	1.2	5.1	3.7
Interest expense	(8.3)	(8.1)	(24.3)	(16.5)
Earnings from equity method investments	8.1	10.8	38.7	23.6
Non-controlling interest in income	(1.2)	(0.3)	(2.7)	(0.3)
Net income (loss)	$ 152.7	$ 7.5	$ (13.1)	$ 24.1
Less:				
Net income attributable to predecessor operations				(3.6)
General partner interest in net income or net loss	(4.9)	(0.9)	(7.1)	(1.5)
Net income (loss) allocable to limited partners	$ 147.8	$ 6.6	$ (20.2)	$ 19.0
Net income (loss) income per limited partner unit basic and diluted	$ 2.97	$ 0.29	$ (0.75)	$ 0.89
Weighted-average limited partner units outstanding basic and diluted	28.2	22.3	27.1	19.3

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(Millions)			
Net income (loss)	$ 152.7	$ 7.5	$ (13.1)	$ 24.1
Other comprehensive loss:				
Reclassification of cash flow hedges into earnings	2.3	(0.7)	5.0	(2.8)
Net unrealized losses on cash flow hedges	(4.4)	(5.7)	(5.5)	(11.4)
Total other comprehensive loss	(2.1)	(6.4)	(0.5)	(14.2)
Total comprehensive income (loss)	$ 150.6	$ 1.1	$ (13.6)	$ 9.9

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, 2008	Nine Months Ended September 30, 2007
	(Millions)	
OPERATING ACTIVITIES:		
Net (loss) income	$ (13.1)	$ 24.1
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation and amortization expense	26.3	15.8
Earnings from equity method investments, net of distributions	11.2	3.5
Non-controlling interest in income	2.7	0.3
Other, net	(0.6)	(0.7)
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:		
Accounts receivable	45.5	(2.1)
Inventories	5.5	2.1
Net unrealized losses on derivative instruments	44.6	19.9
Accounts payable	(85.9)	(2.2)
Accrued interest		0.2
Other current assets and liabilities	18.7	4.3
Other long-term assets and liabilities	(0.2)	0.9
Net cash provided by operating activities	54.7	66.1
INVESTING ACTIVITIES:		
Capital expenditures	(23.0)	(11.6)
Acquisition of subsidiaries of Momentum Energy Group, Inc., net of cash acquired	(10.9)	(142.0)
Acquisition of assets		(191.3)
Acquisition of equity method investments		(153.3)
Investments in equity method investments	(5.7)	(4.3)
Payment of earnest deposit		(9.0)
Refund of earnest deposit		9.0
Proceeds from sales of assets	2.5	0.1
Purchases of available-for-sale securities	(532.2)	(6,789.8)
Proceeds from sales of available-for-sale securities	410.9	6,793.1
Net cash used in investing activities	(158.4)	(499.1)
FINANCING ACTIVITIES:		
Proceeds from debt	432.0	569.0
Payments of debt	(407.0)	(207.0)
Payment of deferred financing costs		(0.6)
Proceeds from issuance of common units, net of offering costs	132.1	228.5
Purchase of units		(0.2)
Excess purchase price over acquired assets		(100.3)
Net change in advances from DCP Midstream, LLC		(14.6)
Distributions to unitholders	(55.4)	(28.8)
Contributions from non-controlling interests	2.8	
Distributions to non-controlling interests	(3.2)	
Contributions from DCP Midstream, LLC	1.9	0.4

Distributions to DCP Midstream, LLC	(0.5)	
Net cash provided by financing activities	102.7	446.4
Net change in cash and cash equivalents	(1.0)	13.4
Cash and cash equivalents, beginning of period	24.5	46.2
Cash and cash equivalents, end of period	$ 23.5	$ 59.6

See accompanying notes to condensed consolidated financial statements.

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, producing, transporting, storing and selling propane and transporting and selling NGLs and condensate.

We are a Delaware master limited partnership. Our partnership includes: our Northern Louisiana system; our Southern Oklahoma system (acquired in May 2007); our limited liability company interests in DCP East Texas Holdings, LLC, or East Texas, and Discovery Producer Services LLC, or Discovery (acquired in July 2007); our Wyoming system and a 70% interest in our Colorado system (each acquired in August 2007); our wholesale propane logistics business; and our NGL transportation pipelines.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, which is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC and its affiliates employees provide administrative support to us and operate our assets. DCP Midstream, LLC owns approximately 30% of our partnership.

The acquisition from DCP Midstream, LLC in July 2007 of our limited liability company interest in East Texas and Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, was a transaction among entities under common control. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC s basis in the net assets contributed. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, prior periods are retroactively adjusted to furnish comparative information similar to the pooling method and the amount of the purchase price in excess of DCP Midstream, LLC s basis in the net assets, if any, is recognized as a reduction to partners equity. Accordingly, our financial information includes the historical results of East Texas, Discovery and the Swap for all periods presented. In addition, the results of operations of our Southern Oklahoma, Wyoming and Colorado systems have been included in the condensed consolidated financial statements since their respective acquisition dates.

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 equity interests in East Texas and Discovery, and the Swap, for periods prior to our acquisition, 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 2007 Form 10-K.

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.

Fair Value Measurements We measure our derivative financial assets and liabilities related to our commodity derivative activity and our interest rate swaps at fair value as of each balance sheet date. While we utilize as much information as is readily

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

observable in the marketplace in determining fair value, to the extent that information is not available we may use a combination of indirectly observable facts or, in certain instances, may develop our own expectation of the fair value. Calculating the fair value of an instrument is a highly subjective process and involves a significant level of judgment based on our interpretation of a variety of market conditions. The resulting fair value may be significantly different from one measurement date to the next. All realized and unrealized gains and losses, and settlements of commodity derivative instruments are recorded in the condensed consolidated statements of operations as losses from commodity derivative activity, net. All unrealized gains and losses resulting from changes in the fair value of our interest rates swaps are recorded in the condensed consolidated balance sheets within accumulated other comprehensive income, or AOCI.

3. Recent Accounting Pronouncements

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

FASB Staff Position, or FSP, No. SFAS 142-3 Determination of the Useful Life of Intangible Assets, **or FSP 142-3** In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3 on our consolidated results of operations, cash flows or financial position.

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

SFAS No. 160 Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51, **or SFAS 160** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. We are assessing the impact of the adoption of SFAS 160, and believe that it will not have a significant impact on our consolidated results of operations, cash flows or financial position. Any required changes to presentation and disclosures will be made in our first filing following the effective date of this standard.

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

***SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FAS 115*, or SFAS 159** In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. The provisions of SFAS 159 were

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in our consolidated results of operations, cash flows or financial position.

***SFAS No. 157, Fair Value Measurements*, or SFAS 157** In September 2006, the FASB issued SFAS 157, which was effective for us on January 1, 2008. SFAS 157:

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

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we recorded a transition adjustment of approximately $5.8 million as an increase to earnings and approximately $1.3 million as an increase to AOCI during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we have not assessed the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities.

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

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

4. Acquisitions

Gathering and Compression Assets

In August 2007, we acquired certain subsidiaries of Momentum Energy Group, Inc., or MEG, from DCP Midstream, LLC for approximately $165.8 million. As a result of the acquisition, we expanded our operations into the Piceance and Powder River producing basins, thus diversifying our business into new operating areas. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments totaling $10.9 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of borrowings under our credit

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

agreement, along with the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate. The proceeds from this private placement were used to purchase high-grade securities to fully secure our term loan borrowings. These units were registered with the SEC in January 2008.

The transfer of the MEG subsidiaries between DCP Midstream, LLC and us represents a transfer between entities under common control. Transfers between entities under common control are accounted for at DCP Midstream, LLC s carrying value, similar to the pooling method. DCP Midstream, LLC recorded its acquisition of the MEG subsidiaries under the purchase method of accounting, whereby the assets and liabilities were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $52.8 million, including purchase price adjustments of $1.9 million during the first quarter of 2008. The goodwill amount recognized relates primarily to projected growth in the Piceance basin due to significant natural gas reserves and high levels of drilling activity. The purchase price allocation is as follows:

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

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

In April 2007, we acquired certain gathering and compression assets located in northern Louisiana from Laser Gathering Company, LP for approximately $10.2 million.

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

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 $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.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Agreements and Transactions with Affiliates
DCP Midstream, LLC

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for certain costs incurred and centralized corporate functions performed by DCP Midstream, LLC on our behalf. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, totaling $63.0 million at September 30, 2008, to certain counterparties to our commodity derivative instruments. During the three months ended September 30, 2008 and 2007, we incurred $2.4 million and $2.1 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $0.4 million for both periods. During the nine months ended September 30, 2008 and 2007, we incurred $7.3 million and $5.6 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $1.3 million and $1.6 million, respectively.

Other Agreements and Transactions with DCP Midstream, LLC

We sell a portion of our residue gas and NGLs to, purchase raw natural gas and other petroleum products from, and provide gathering and transportation services for, DCP Midstream, LLC. We anticipate continuing to purchase commodities from and sell commodities to DCP Midstream, LLC in the ordinary course of business. In addition, DCP Midstream, LLC conducts derivative activities on our behalf.

DCP Midstream, LLC was a significant customer during the three and nine months ended September 30, 2008 and 2007.

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. DCP Midstream, LLC has made capital contributions of $1.6 million to us during the nine months ended September 30, 2008 to reimburse us for these capital projects.

In July 2008, DCP Midstream, LLC issued additional parental guarantees outside of the Omnibus Agreement, totaling $200.0 million, to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. These guarantees were reduced to $150.0 million during the third quarter of 2008 to correspond with lower commodity prices and collateral requirements. We pay DCP Midstream, LLC a fee of 0.5% per annum on these outstanding guarantees.

Spectra Energy

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

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

ConocoPhillips

We have multiple agreements whereby we provide a variety of services for ConocoPhillips and its affiliates. The agreements include fee-based and percent-of-proceeds gathering and processing arrangements, gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received $1.8 million and $2.4 million of capital reimbursements during the nine months ended September 30, 2008 and 2007, respectively.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Summary of Transactions with Affiliates

The following table summarizes the transactions with affiliates:

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$ 133.1	$ 70.3	$ 398.7	$ 184.2
Transportation, processing and other	$ 1.9	$ 1.5	$ 13.6	$ 4.4
Purchases of natural gas, propane and NGLs	$ 30.6	$ 24.1	$ 134.0	$ 94.1
Losses from commodity derivative activity, net	$ (1.4)	$ (1.4)	$ (2.5)	$ (1.9)
General and administrative expense	$ 2.8	$ 2.5	$ 8.6	$ 7.2
Interest expense	$ 0.3	$	$ 0.3	$
Spectra Energy:				
Sales of natural gas, propane, NGLs and condensate	$	$	$ 0.2	$
Transportation, processing and other	$	$	$ 0.1	$
Purchases of natural gas, propane and NGLs	$ 21.9	$	$ 26.3	$
ConocoPhillips:				
Sales of natural gas, propane, NGLs and condensate	$ 0.2	$ 3.3	$ 1.8	$ 6.0
Transportation, processing and other	$ 2.3	$ 2.9	$ 8.0	$ 7.9
Purchases of natural gas, propane and NGLs	$ 10.7	$ 7.9	$ 33.6	$ 21.4

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

	September 30, 2008	December 31, 2007
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 39.2	$ 47.3
Accounts payable	$ 16.2	$ 53.3
Spectra Energy:		
Accounts receivable	$ 5.1	$ 1.5
Accounts payable	$	$
ConocoPhillips:		
Accounts receivable	$ 2.5	$ 3.3
Accounts payable	$ 1.6	$ 2.3

6. Fair Value Measurement

Determination of Fair Value

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

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in an inactive (or less active) market for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

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

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 9 Risk Management and Hedging Activities.

Valuation Hierarchy

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

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

Level 2 inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 inputs are unobservable and considered significant to the fair value measurement.

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

Commodity Derivative Assets and Liabilities

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

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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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

Interest Rate Derivative Assets and Liabilities

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

Short-Term and Restricted Investments

We are required to post collateral to secure the term loan portion of our credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated tax-exempt debt securities that have stated maturities of 20 years or less, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. Given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper and highly rated tax-exempt debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2. As of September 30, 2008, nearly all of our short-term and restricted investments were held in the form of money market securities. By virtue of our balances in these funds on September 19, 2008, all of these investments are eligible for, and the funds are participating in, the U.S. Treasury Department s Temporary Guarantee Program for Money Market Funds.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following table presents the financial instruments carried at fair value as of September 30, 2008, by condensed consolidated balance sheet caption and by valuation hierarchy, as described above:

	Quoted Market Prices In Active Markets (Level 1)	Internal Models With Significant Observable Market Inputs (Level 2)	Internal Models With Significant Unobservable Market Inputs (Level 3)	Total Carrying Value
			(Millions)	
Current assets:				
Short-term investments	$	$ 2.5	$	$ 2.5
Commodity derivative instruments (a)	$	$ 1.5	$ 1.8	$ 3.3
Long-term assets:				
Restricted investments	$	$ 221.1	$	$ 221.1
Commodity derivative instruments (b)	$	$	$ 1.3	$ 1.3
Interest rate instruments (b)	$	$ 0.2	$	$ 0.2
Current liabilities (c):				
Commodity derivative instruments	$	$ (29.1)	$ (0.1)	$ (29.2)
Interest rate instruments	$	$ (6.9)	$	$ (6.9)
Long-term liabilities (d):				
Commodity derivative instruments	$	$ (102.1)	$	$ (102.1)
Interest rate instruments	$	$ (6.8)	$	$ (6.8)

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

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

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

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

Changes in Level 3 Fair Value Measurements

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

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Balance at December 31, 2007	Net Realized and Unrealized Gains (Losses) Included in Earnings	Transfers In/ Out of Level 3 (a)	Purchases, Issuances and Settlements, Net	Balance at September 30, 2008	Net Unrealized Gains (Losses) Still Held Included in Earnings (b)
			(Millions)			
Commodity derivative instruments:						
Current assets	$ 0.2	$ 2.0	$	$ (0.4)	$ 1.8	$ 1.8
Long-term assets	$ 1.5	$ (0.2)	$	$	$ 1.3	$ (0.3)
Current liabilities	$ (1.6)	$ (0.3)	$	$ 1.8	$ (0.1)	$ (0.1)
Long-term liabilities	$ (0.2)	$ 0.2	$	$	$	$ 0.2

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

(b) Represents the amount of total gains or losses for the period, included in losses from commodity derivative activity, net, attributable to change in unrealized gains (losses) relating to assets and liabilities classified as Level 3 that are still held at September 30, 2008.

7. Debt

Long-term debt was as follows:

	September 30, 2008	December 31, 2007
	(Millions)	
Revolving credit facility, weighted-average interest rate of 3.51% and 5.47%, respectively, due June 21, 2012 (a)	$ 435.0	$ 530.0
Term loan facility, interest rate of 2.59% and 5.05%, respectively, due June 21, 2012	220.0	100.0
Total long-term debt	$ 655.0	$ 630.0

(a) $425.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 3.97% to 5.19%, for a net effective rate of 5.19% on the $435.0 million of outstanding debt under our revolving credit facility as of September 30, 2008.

Credit Agreement

We have a 5-year credit agreement that matures June 21, 2012, or the Credit Agreement, consisting of a $630.0 million revolving credit facility and a $220.0 million term loan facility. 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, 2008 and December 31, 2007. The unused portion of the revolving credit facility may be used for general corporate purposes and letters of credit. At September 30, 2008 and December 31, 2007, we had $0.3 million and $0.2 million of letters of credit outstanding under the Credit Agreement, respectively. As of September 30, 2008, the available capacity under our credit facility was $182.8 million.

Lehman Brothers Commercial Bank, or Lehman Brothers, is a lender in our Credit Agreement. Lehman Brothers has not funded its portion of our borrowing requests associated with the Michigan acquisition, and it is uncertain whether it will fund future borrowing requests. Accordingly, unless Lehman Brothers transfers their commitment to another commercial lender to the credit facility, we expect the availability of new borrowings under the existing $850.0 million credit agreement to be reduced by up to approximately $25.4 million. Our borrowing capacity may be further limited by the Credit Agreement s financial covenant requirements. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the June 21, 2012 maturity date.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Other Agreements

As of September 30, 2008, we had outstanding letters of credit with counterparties to our commodity derivative instruments of $75.0 million, which reduce the amount of cash we may be required to post as collateral. These letters of credit were issued directly by financial institutions and do not reduce the available capacity under our credit facility.

8. Partnership Equity and Distributions

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

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

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

- less the amount of cash reserves established by the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to the unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

General Partner Interest and Incentive Distribution Rights Prior to June 2007, the general partner was entitled to 2% of all quarterly distributions that we make prior to our liquidation. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner has not participated in certain issuances of common units. Therefore, the general partner s 2% interest has been diluted to 1.3% as of September 30, 2008.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash as pre-defined distribution targets have been achieved. The general partner s incentive distribution rights were not reduced as a result of our March 2008 common limited partner unit offering, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest. Please read the *Distributions of Available Cash during the Subordination Period* and *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on the general partner s incentive distribution rights.

Subordinated Units All of the subordinated units are held by 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. We determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2008 and, therefore, 50% of the subordinated units, or 3,571,428 units, converted into common units. Our board of directors certified that all

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

conditions for early conversion were satisfied. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Distributions of Available Cash during the Subordination Period Our partnership agreement, after adjustment for the general partner s relative ownership level, currently 1.3%, requires that we make distributions of Available Cash for any quarter during the subordination period in the following manner:

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

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

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

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

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

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

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

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

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

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

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

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

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

Payment Date	**Per Unit Distribution**	**Total Cash Distribution (Millions)**
August 14, 2008	$ 0.600	$ 20.1
May 15, 2008	0.590	19.6
February 14, 2008	0.570	15.7
November 14, 2007	0.550	14.7
August 14, 2007	0.530	12.4
May 15, 2007	0.465	8.6
February 14, 2007	0.430	7.8

Our current distribution places us in the Fourth Target Distribution level.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. Risk Management and Hedging Activities

The impact of our derivative activity on our results of operations and financial position is summarized below:

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Millions)			
Commodity cash flow hedges:				
(Losses) gains reclassified into earnings	$ (0.1)	$ 0.5	$ (0.5)	$ 2.3
Commodity derivative activity:				
Unrealized gains (losses) from derivative activity	$ 154.4	$ (5.6)	$ (43.9)	$ (20.5)
Realized losses from derivative activity	$ (12.4)	$ (0.5)	$ (37.8)	$ (0.6)
Interest rate cash flow hedges:				
(Losses) gains reclassified into earnings	$ (2.2)	$ 0.2	$ (4.5)	$ 0.5

	September 30, 2008	December 31, 2007
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (2.1)	$ (2.6)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	$ (13.3)	$ (12.3)

For the three and nine months ended September 30, 2008 and 2007, 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.

As of September 30, 2008, we had outstanding letters of credit with counterparties to our commodity derivative instruments of $75.0 million. These letters of credit reduce the amount of cash we may be required to post as collateral. As of September 30, 2008, we had no cash collateral posted with counterparties to our commodity derivative instruments.

Commodity Cash Flow Protection Activities We used NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGLs, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was accumulated in AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to the 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 derivative instruments. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings. Deferred net losses of $1.0 million are expected to be reclassified during the next 12 months. Subsequent to July 1, 2007, the changes in fair value of financial derivatives are included in losses from commodity derivative activity, net, in the condensed consolidated statements of operations. The agreements are with major financial institutions, which management expects to fully perform under the terms of the agreements.

Commodity Fair Value Hedges Historically, we used fair value hedges to mitigate risk to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) to reduce our cash flow exposure to fixed price risk by swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index-based).

Interest Rate Cash Flow Hedges We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $425.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheets. Deferred net losses of $6.7 million 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 3.97% to 5.19%, and receive interest payments based on the three-month London Interbank Offered Rate, or 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 management expects to fully perform under the terms of the agreements.

10. Net Income (Loss) per Limited Partner Unit

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

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

These required disclosures do not impact our overall net income or loss, or other financial results; however, in periods in which aggregate net income exceeds the First Target Distribution Level, it will have the impact of reducing net income per limited partner unit, or 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, 2008, our aggregate net income per LPU exceeded the Fourth Target Distribution level, and as a result, we allocated $63.9 million in additional earnings to the general partner. 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 no additional earnings were allocated to the general partner.

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

The following table illustrates our calculation of net income (loss) per LPU:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(Millions)			
Net income (loss)	$ 152.7	$ 7.5	$ (13.1)	$ 24.1
Less:				
Net income attributable to predecessor operations				(3.6)

Net income (loss) attributable to the partnership	152.7	7.5	(13.1)	20.5
Less: General partner interest in net income or net loss	(4.9)	(0.9)	(7.1)	(1.5)
Limited partners interest in net income (loss)	147.8	6.6	(20.2)	19.0
Less: Additional earnings allocation to general partner	(63.9)			(1.8)
Net income (loss) available to limited partners	$ 83.9	$ 6.6	$ (20.2)	$ 17.2
Net income (loss) per LPU basic and diluted	$ 2.97	$ 0.29	$ (0.75)	$ 0.89

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Commitments and Contingent Liabilities

Litigation We are a party to various legal proceedings, as well as 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 these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our consolidated results of operations, financial position, or cash flows. See Note 16 in Item 8 of our 2007 Form 10-K for additional details.

Indemnification DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors. See the Indemnification section of Note 5 in Item 8 of our 2007 Form 10-K for additional details.

12. Business Segments

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

Natural Gas Services The Natural Gas Services segment consists of (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; and (4) our Colorado and Wyoming systems, acquired in August 2007.

Wholesale Propane Logistics The Wholesale Propane Logistics segment consists of six owned rail terminals, one of which is currently idle, one leased marine terminal, one pipeline terminal that became operational in May 2007, and access to several open-access pipeline terminals. We generally offer our customers the ability to obtain propane supply volumes from us in the winter months that are generally significantly greater than their purchase of propane from us in the summer.

NGL Logistics The NGL Logistics segment consists of our Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline.

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.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following tables set forth our segment information:

Three Months Ended September 30, 2008

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics (Millions)	Other	Total
Total operating revenue	$ 341.3	$ 82.0	$ 3.5	$	$ 426.8
Gross margin (a)	$ 174.9	$ 0.9	$ 1.6	$	$ 177.4
Operating and maintenance expense	(7.9)	(1.9)	(0.4)		(10.2)
Depreciation and amortization expense	(8.1)	(0.3)	(0.4)		(8.8)
General and administrative expense				(6.0)	(6.0)
Earnings from equity method investments	7.8		0.3		8.1
Interest income				1.7	1.7
Interest expense				(8.3)	(8.3)
Non-controlling interest in income	(1.2)				(1.2)
Net income (loss)	$ 165.5	$ (1.3)	$ 1.1	$ (12.6)	$ 152.7
Non-cash derivative mark-to-market (b)	$ 154.1	$ 0.2	$	$	$ 154.3
Capital expenditures	$ 5.1	$ 0.7	$ 0.1	$	$ 5.9

Three Months Ended September 30, 2007

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics (Millions)	Other	Total
Total operating revenues	$ 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
Non-cash derivative mark-to-market (b)	$	(3.9)	$	(1.0)	$		$		$	(4.9)
Capital expenditures	$	3.1	$	0.6	$	0.3	$		$	4.0

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Nine Months Ended September 30, 2008

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 523.6	$ 378.0	$ 8.8	$	$ 910.4
Gross margin (a)	$ 26.2	$ 11.9	$ 5.4	$	$ 43.5
Operating and maintenance expense	(23.7)	(7.3)	(0.8)		(31.8)
Depreciation and amortization expense	(24.3)	(0.9)	(1.1)		(26.3)
General and administrative expense				(16.8)	(16.8)
Other		1.5			1.5
Earnings from equity method investments	37.8		0.9		38.7
Interest income				5.1	5.1
Interest expense				(24.3)	(24.3)
Non-controlling interest in income	(2.7)				(2.7)
Net income (loss)	$ 13.3	$ 5.2	$ 4.4	$ (36.0)	$ (13.1)
Non-cash derivative mark-to-market (b)	$ (47.1)	$ 2.7	$	$ (0.2)	$ (44.6)
Capital expenditures	$ 20.0	$ 2.7	$ 0.3	$	$ 23.0

Nine Months Ended September 30, 2007

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenues	$ 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

Non-cash derivative mark-to-market (b)	$ (18.4)	$ (1.5)	$	$	$ (19.9)
Capital expenditures	$ 7.2	$ 3.2	$ 1.2	$	$ 11.6

	September 30, 2008	December 31, 2007
	(Millions)	
Segment long-term assets:		
Natural Gas Services	$ 699.6	$ 710.7
Wholesale Propane Logistics	54.4	52.6
NGL Logistics	34.6	34.8
Other (c)	224.2	104.1
Total long-term assets	1,012.8	902.2
Current assets	149.5	218.5
Total assets	$ 1,162.3	$ 1,120.7

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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

13. Supplemental Cash Flow Information

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Millions)	
Cash paid for interest, net of amounts capitalized	$ 19.7	$ 17.3
Non-cash investing and financing activities:		
Net decrease in property, plant and equipment	$ (5.3)	$ (5.3)

14. Subsequent Events

In October 2008, we acquired Michigan Pipeline & Processing, LLC, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.1 million, subject to additional customary purchase price adjustments. We may pay up to an additional $15.0 million to the sellers depending on the earnings of the assets after a three-year period. We financed the acquisition with liquidation of a portion of our restricted investments. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller will pay us up to $1.5 million annually for up to nine years for this service; however, this agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. We hold a $25.0 million letter of credit to secure the seller s performance under this agreement and to secure the seller s indemnification obligation under the acquisition agreement. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

On October 23, 2008, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on November 14, 2008 to unitholders of record on November 7, 2008. This distribution of $0.60 per unit places us in the Fourth Target Distribution level (see Note 8 of the Notes to Condensed Consolidated Financial Statements in Item 1. Financial Statements for discussion of distributions of available cash).

In October 2008, we received distributions of $7.2 million from Discovery and paid contributions of $3.6 million to Discovery to fund capital expansion, of which $2.2 million was reimbursed by DCP Midstream, LLC.

As of September 30, 2008, DCP Midstream, LLC had issued parental guarantees totaling $63.0 million under the Omnibus Agreement and $150.0 million outside of the Omnibus Agreement to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. These guarantees were reduced to correspond with lower commodity prices and collateral requirements by $35.0 million, to $178.0 million as of November 3, 2008.

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Item 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and the consolidated financial statements and notes thereto included in our 2007 Form 10-K. We refer to our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, and our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, as well as 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 predecessor. The financial information contained herein includes, for each period presented, our accounts, and those of our predecessor.

Overview

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

- our Natural Gas Services segment, which consists of (1) our Northern Louisiana natural gas gathering, processing and transportation system; (2) our Southern Oklahoma system acquired in May 2007; (3) our limited liability company interest in East Texas, our limited liability company interest in Discovery, and the Swap, acquired in July 2007 from DCP Midstream, LLC; and (4) our Colorado and Wyoming systems, acquired in August 2007 from DCP Midstream, LLC, which were acquired by DCP Midstream, LLC from Momentum Energy Group, Inc. in August 2007 (referred to as the MEG acquisition);

- our Wholesale Propane Logistics segment, which consists of six owned rail terminals, one of which is currently idle, one leased marine terminal, one pipeline terminal that became operational in May 2007, and access to several open-access pipeline terminals; and

- our NGL Logistics segment, which consists of our Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline.

Recent Events

As of November 3, 2008, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $178.0 million to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We pay DCP Midstream, LLC a fee of 0.5% per annum on $115.0 million of these guarantees. The fee on the remaining guarantees is covered under the omnibus agreement with DCP Midstream, LLC. During the second and third quarters of 2008, we issued letters of credit totaling $75.0 million to counterparties to our commodity derivative instruments, which reduce the amount of cash we may be required to post as collateral. These letters of credit were issued directly by financial institutions and do not reduce the available capacity under our credit facility.

We completed pipeline integrity testing at our Wyoming system during the second quarter of 2008 and commenced work on the pipeline to bring it back to normal operations. We are further upgrading our Wyoming system to assure future integrity, improve system reliability and reduce operating costs. We believe this work will be completed at a total cost of approximately $13.0 million, the majority of which is maintenance capital. Of the $13.0 million, approximately $1.6 million was incurred through the third quarter of 2008. We believe we will recover the costs of this work over time. The work on the pipeline will be completed in phases so that volumes will return to the system throughout the fourth quarter of 2008 and into the first quarter of 2009. We anticipate decreased operating revenues through the first quarter of 2009 as we complete this work.

Angela A. Minas was appointed vice president and chief financial officer of our general partner, effective September 8, 2008. In addition, Thomas C. O Connor, Chief Executive Officer of DCP Midstream, LLC, replaced Fred J. Fowler as Chairman of the Board of our general partner, effective September 1, 2008. Mr. Fowler will remain a director of our general partner s board of directors.

During the third quarter of 2008, we announced that Collbran Valley Gas Gathering, LLC, or Collbran, plans to invest approximately $150.0 million over a multi-year period to construct approximately 20 miles of 24-inch diameter gathering pipeline, and compression and liquids handling facilities, to support its Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. We are the operator and 70% owner of Collbran. The gathering system is designed to ultimately have throughput capacity of over 600 million cubic feet per day, or MMcf/d, and is supported by long-term acreage dedications from Plains Exploration & Production Company and Delta Petroleum

Corporation, which own 25% and 5% of

Collbran, respectively, and a long-term dedication from a subsidiary of Enterprise Products Partners LP covering gas that it has the right to gather from a specified, dedicated area within the Piceance Basin. Collbran will invest approximately $100.0 million in 2008 and 2009 to achieve throughput capacity of approximately 300 MMcf/d by the second quarter of 2009. The remaining investment in primarily compression equipment of approximately $50.0 million will be spent in 2010 through 2013 as production volumes increase, providing total throughput capacity in excess of 600 MMcf/d. We ultimately expect to invest approximately $105.0 million in this project, in proportion to our respective ownership interest.

During the third quarter of 2008, we announced plans, along with DCP Midstream, LLC, to invest approximately $56.0 million in East Texas to construct a gathering pipeline to support the East Texas system. Our interest in this pipeline is 25%. The pipeline is scheduled to be operational during the second quarter of 2009.

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

In October 2008, due to executive management rotational changes at ConocoPhillips, Willie C.W. Chiang and Sigmund L. Cornelius resigned as directors of the board of directors of our general partner, and John E. Lowe and Gregory J. Goff were appointed as the ConocoPhillips representatives to the board of directors. Mr. Lowe currently serves as assistant to the Chief Executive Officer of ConocoPhillips, an affiliate of our general partner and Mr. Goff currently serves as Senior Vice President, Commercial of ConocoPhillips.

In October 2008, we acquired Michigan Pipeline & Processing, LLC, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.1 million, subject to additional customary purchase price adjustments, plus up to an additional $15.0 million to the sellers depending on the earnings of the assets after a three-year period. We financed the acquisition with liquidation of a portion of our restricted investments. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller will pay us up to $1.5 million annually for up to nine years for this service; however, this agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. We hold a $25.0 million letter of credit to secure the seller s performance under this agreement and to secure the seller s indemnification obligation under the acquisition agreement. The fees under the omnibus agreement with DCP Midstream, LLC increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

On October 23, 2008, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on November 14, 2008 to unitholders of record on November 7, 2008. This distribution of $0.60 per unit places us in the Fourth Target Distribution level (see Note 8 of the Notes to Condensed Consolidated Financial Statements in Item 1. Financial Statements for discussion of distributions of available cash).

In October 2008, we received distributions of $7.2 million from Discovery and paid contributions of $3.6 million to Discovery to fund capital expansion, of which $2.2 million was reimbursed by DCP Midstream, LLC. In September 2008 we received distributions of $3.3 million from East Texas and paid a contribution of $1.3 million to East Texas to fund capital expansion.

Factors That Significantly Affect Our Results

Capital Markets

Beginning in the third quarter of 2008, the capital markets experienced volatility, uncertainty and interventions by various governments around the globe. The effects of these market conditions include significant changes in the valuation of equity securities and overnight and longer-term borrowing rates. The availability of credit through traditional sources of funding such as the commercial paper, bank lending and the private and public placement debt markets also decreased dramatically. The uncertainty in the capital markets may impact our business in multiple ways, including limiting our producers ability to finance their drilling programs and limiting our ability to grow our operations through acquisitions or organic growth projects. These events may impact our counterparties ability to perform under their credit or commercial obligations. We have not observed any change in the routine payment patterns of our customers, and where possible we have obtained additional collateral agreements, letters of credit from highly rated banks, or have managed credit lines. To date, our counterparties to our existing derivative instruments have fully performed under their commitments. Due to the financial troubles of one of the lenders to our Credit Agreement, however, the availability of borrowings under this facility has been reduced by approximately $21.1 million as of November 3, 2008.

Impact of Hurricanes

As a result of hurricanes during the third quarter of 2008, certain of our owned and operated facilities were fully or partially curtailed pending resumption of operations at downstream third party NGL facilities in some cases and restoration of electric power service. All of our operated assets have been returned to service. There could be some temporary impact to demand as third party NGL facilities are fully returned to service. Additionally, Discovery s offshore gathering system sustained damage as a result of hurricanes and is not accepting gas from offshore producers while repairs are being made. Inspections of the system revealed that an 18-inch lateral was severed from its connection to the 30-inch mainline in approximately 250 feet of water. Williams expects the 30-inch line to be repaired and returned to service by December 2008. Due to ongoing damage assessments, the repair schedule for the 18-inch lateral has not yet been finalized. The net income impact of hurricane-related damages and lost margins due to curtailed operations for the third quarter of 2008 was approximately $5.0 to $6.0 million, including losses from our equity method investment in Discovery. We estimate a net income impact of hurricane-related damages and lost margins due to curtailed operations for the fourth quarter of 2008 of approximately $7.0 million to $12.0 million. We do not anticipate receiving a distribution from Discovery during the first quarter of 2009 reflecting fourth quarter activity.

Other Factors

Deterioration in commodity prices did not cause a goodwill or asset impairment charge as of September 30, 2008. Future deterioration in commodity prices, unit prices or other market declines may increase the likelihood of a goodwill or asset impairment charge. An impairment charge would arise if the fair value is less than the carrying value. We determine fair value using widely accepted valuation techniques, namely discounted cash flow and market multiple analyses. These techniques are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors, and the profitability of future business strategies. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill or asset impairment charges.

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, which are collectively referred to as our predecessor, from DCP Midstream, LLC, in a transaction among entities under common control. Accordingly, our financial information includes the historical results of our predecessor for each period presented. Prior to July 2007, our financial statements do not give effect to various items that affected our results of operations and liquidity following this acquisition, including the indebtedness we incurred in conjunction with the closing of this acquisition, which increased our interest expense from the interest expense reflected in our historical financial statements.

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

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

Additionally, our results of operations for our Natural Gas Services segment are impacted by market conditions causing variability in natural gas, crude oil and NGL prices. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally correlated to the price of crude oil. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close correlation. Changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary significantly.

Based on historical trends, however, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather, and the level of worldwide economic growth. Drilling activity can be

adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity in the future. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed.

We have mitigated a portion of the anticipated commodity price risk associated with the equity volumes from our gathering and processing operations, for both our consolidated entities and our proportionate share of exposure from our equity method investments, through 2013 with natural gas and crude oil swaps. We also mitigate a portion of the anticipated commodity price risk associated with fixed price propane sales by entering into either offsetting physical purchase agreements or financial derivative instruments, with DCP Midstream, LLC or third parties, which typically match the quantities of propane subject to these fixed price sales agreements. We mark these derivative instruments to market through current period earnings based upon their fair value. While the swaps may mitigate the variability of our future cash flows resulting from changes in commodity prices, the mark-to-market method of accounting significantly increases the volatility of our net income because we recognize, in current period operating revenues, all non-cash gains and losses from the changes in the fair value of these derivatives.

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

For the nine months ended September 30, 2008, the net loss recorded in operating revenues for commodity derivatives was $81.7 million. Of the loss, $37.8 million was related to cash settlements during 2008. The fair value of commodity derivatives was a net liability of $126.7 million as of September 30, 2008. Prior to our initial public offering, DCP Midstream provided parental guarantees, totaling $63.0 million, to certain counterparties to our commodity derivative instruments. In July 2008, DCP Midstream provided additional parental guarantees totaling $200.0 million to certain counterparties to our commodity derivative instruments. These parental guarantees totaled $178.0 million as of November 3, 2008. As of November 3, 2008, we had letters of credit totaling $75.0 million. These parental guarantees and letters of credit reduce the amount of cash we may be required to post as collateral. As of November 3, 2008, we had no cash collateral posted with counterparties.

We completed pipeline integrity testing at our Wyoming system during the second quarter of 2008 and commenced work on the pipeline to bring it back to normal operations. We are further upgrading our Wyoming system to assure future integrity, improve system reliability and reduce operating costs. We believe this work will be completed at a total cost of approximately $13.0 million, the majority of which is maintenance capital. Of the $13.0 million, approximately $1.6 million was incurred through the third quarter of 2008. We believe we will recover the costs of this work over time. The work on the pipeline will be completed in phases so that volumes will return to the system throughout the fourth quarter of 2008 and into the first quarter of 2009. We anticipate decreased operating revenues through the first quarter of 2009 as we complete this work.

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

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 areas 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.

The Black Lake pipeline has experienced increased operating costs due to pipeline integrity testing that commenced in 2005 and was completed during the second quarter of 2008. Testing revealed irregularities, the more severe of which were repaired in October 2008 and the less severe of which are scheduled for repair in 2009. DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions 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. We anticipate

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repairs of approximately $0.5 million on the pipeline. 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. We have not made any capital contributions to Black Lake associated with repairing the Black Lake pipeline.

Our Operations

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

Natural Gas Services Segment

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

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

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

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

We have mitigated a portion of our anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with natural gas and crude oil swaps. With these swaps, we expect our cash flow exposure to commodity price movements to be reduced. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Commodity Cash Flow Protection Activities in our 2007 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 derivative financial instruments, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on derivative activity.

The natural gas supply for our gathering pipelines and processing plants is derived primarily from natural gas wells located in Colorado, Louisiana, Oklahoma, Texas, Wyoming and the Gulf of Mexico. The Pelico system also receives natural gas produced in Texas through its interconnect with other pipelines that transport natural gas from Texas into western Louisiana. These areas have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. Our three primary suppliers of natural gas in our Natural Gas Services segment represented approximately 54% of the 357 MMcf/d of natural gas supplied to this system during the nine months ended September 30, 2008. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been released from other gathering systems. In the near term, drilling activity will depend on several factors, including geographic area, targeted products and available capital.

We sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. The NGLs extracted from the natural gas at our processing plants are sold at market index prices to DCP Midstream, LLC or its affiliates, or to third parties. In addition, under our merchant arrangements, we use a subsidiary of DCP Midstream, LLC as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties. We also have entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that requires DCP Midstream, LLC to supply Pelico s system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index based price less a contractually agreed to marketing fee. In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index. We may enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting. We also gather, process and transport natural gas under fee-based transportation contracts.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the Midwest and northeastern United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Midwest and the northeastern areas of the United States. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our three primary suppliers of propane, one of which is an affiliated entity, represented approximately 82% of our propane supplied during the nine months ended September 30, 2008. We sell propane on a wholesale basis to retail propane distributors who in turn resell propane to their retail customers.

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

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

NGL Logistics Segment

Our pipelines provide transportation services for customers on a fee basis. We have entered into contractual arrangements with DCP Midstream, LLC that require DCP Midstream, LLC to pay us to transport NGLs pursuant to a fee-based rate that is applied to the volumes transported. Therefore, the results of operations for this business segment are generally dependent upon the volume of product transported and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines; rather, the shipper retains title and the associated commodity price risk. For the Seabreeze and Wilbreeze pipelines, we are responsible for any line loss or gain in NGLs. For the Black Lake pipeline, any line loss or gain in NGLs is allocated to the shipper. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the 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, segment gross margin and adjusted segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) EBITDA and adjusted EBITDA; and (5) distributable cash flow. Gross margin, segment gross margin, adjusted segment gross margin, EBITDA, adjusted EBITDA and distributable cash flow measurements are not accounting principles generally accepted in the United States of America, or GAAP, financial measures. We provide reconciliations of certain non-GAAP measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

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

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

We define gross margin as total operating revenues less purchases of natural gas, propane and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases for that segment. Our gross margin equals the sum of our segment gross margins. We define adjusted segment gross margin as segment gross margin plus non-cash derivative losses, less non-cash derivative gains for that segment. Gross margin, segment gross margin and adjusted

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segment gross margin are primary performance measures used by management, as these measures represent the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin, segment gross margin and adjusted segment gross margin should not be considered an alternative to, or more meaningful than, net income or loss, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of net income (loss) to gross margin:				
Net income (loss)	$ 152.7	$ 7.5	$ (13.1)	$ 24.1
Interest expense	8.3	8.1	24.3	16.5
Operating and maintenance expense	10.2	8.1	31.8	21.0
Depreciation and amortization expense	8.8	7.9	26.3	15.8
General and administrative expense	6.0	5.4	16.8	17.1
Other			(1.5)	
Non-controlling interest in income	1.2	0.3	2.7	0.3
Interest income	(1.7)	(1.2)	(5.1)	(3.7)
Earnings from equity method investments	(8.1)	(10.8)	(38.7)	(23.6)
Gross margin	$ 177.4	$ 25.3	$ 43.5	$ 67.5
Non-cash derivative mark-to-market (a)	$ 154.3	$ (4.9)	$ (44.6)	$ (19.9)
Reconciliation of segment net income (loss) to segment gross margin:				
Natural Gas Services segment:				
Segment net income	$ 165.5	$ 19.2	$ 13.3	$ 42.9
Operating and maintenance expense	7.9	5.4	23.7	12.6
Depreciation and amortization expense	8.1	7.4	24.3	14.1
Earnings from equity method investments	(7.8)	(10.3)	(37.8)	(22.6)
Non-controlling interest in income	1.2	0.3	2.7	0.3
Segment gross margin	$ 174.9	$ 22.0	$ 26.2	$ 47.3
Non-cash derivative mark-to-market (a)	$ 154.1	$ (3.9)	$ (47.1)	$ (18.4)
Wholesale Propane Logistics segment:				
Segment net (loss) income	$ (1.3)	$ (0.9)	$ 5.2	$ 8.0
Operating and maintenance expense	1.9	2.5	7.3	7.8
Depreciation and amortization expense	0.3	0.3	0.9	0.7
Other			(1.5)	
Segment gross margin	$ 0.9	$ 1.9	$ 11.9	$ 16.5
Non-cash derivative mark-to-market (a)	$ 0.2	$ (1.0)	$ 2.7	$ (1.5)
NGL Logistics segment:				
Segment net income	$ 1.1	$ 1.5	$ 4.4	$ 3.1

Operating and maintenance expense	0.4	0.2	0.8	0.6
Depreciation and amortization expense	0.4	0.2	1.1	1.0
Earnings from equity method investment	(0.3)	(0.5)	(0.9)	(1.0)
Segment gross margin	$ 1.6	$ 1.4	$ 5.4	$ 3.7

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

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

A substantial amount of our general and administrative expense is incurred from DCP Midstream, LLC. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for certain costs incurred and centralized corporate functions performed by DCP Midstream, LLC on our behalf. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the Michigan acquisition. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, which currently total $63.0 million, to certain counterparties to our commodity derivative instruments. We anticipate incurring a total of $9.8 million for all fees under the Omnibus Agreement in 2008. During the three months ended September 30, 2008 and 2007, we incurred $2.4 million and $2.1 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $ $0.4 million for both periods. During the nine months ended September 30, 2008 and 2007, we incurred $7.3 million and $5.6 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $1.3 million and $1.6 million, respectively. We also incurred third party general and administrative fees of $3.2 million and $8.2 million, and $2.9 million and $9.9 million, for the three and nine months ended September 30, 2008 and 2007, respectively.

The Omnibus Agreement also addresses the following matters:

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

DCP Midstream, LLC s obligation to continue to maintain its credit support for certain obligations related to derivative financial instruments, such as commodity derivative instruments, to the extent that such credit support arrangements were in effect as of December 7, 2005 until the earlier of December 7, 2010 or when we obtain certain credit ratings from either Moody s Investor Services, Inc. or Standard & Poor s Ratings Group with respect to any of our unsecured indebtedness; and

DCP Midstream, LLC s obligation to continue to maintain its credit support for our obligations related to commercial contracts with respect to its business or operations that were in effect at December 7, 2005 until the expiration of such contracts.

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

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

East Texas and Discovery also pay fees to DCP Midstream, LLC and Williams, respectively, for direct costs incurred on their behalf. These fees reduce the amount of cash available from East Texas and Discovery for distribution to us.

EBITDA, Adjusted EBITDA and Distributable Cash Flow We define EBITDA as net income or loss less interest income, plus interest expense, income tax expense and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus non-cash derivative losses, less non-cash derivative gains. EBITDA and adjusted EBITDA are used as supplemental liquidity measures by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures. EBITDA is also a financial measurement that is reported to our lenders, and used as a gauge for compliance with

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our financial covenants under our credit facility, which requires us to maintain: (1) a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters following the consummation of asset acquisitions in the midstream energy business (including the quarter in which such acquisition is consummated), of not more than 5.50 to 1.0; and (2) an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal to or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination. Our EBITDA and adjusted EBITDA may not be comparable to similarly titled measures of another company because other entities may not calculate these measures in the same manner.

EBITDA and adjusted EBITDA are also used as supplemental performance measures 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 and adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations. The following table sets forth reconciliations of EBITDA from its most directly comparable financial measures calculated in accordance with GAAP:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of net income (loss) to EBITDA:				
Net income (loss)	$ 152.7	$ 7.5	$ (13.1)	$ 24.1
Interest income	(1.7)	(1.2)	(5.1)	(3.7)
Interest expense	8.3	8.1	24.3	16.5
Depreciation and amortization expense	8.8	7.9	26.3	15.8
EBITDA	$ 168.1	$ 22.3	$ 32.4	$ 52.7
Reconciliation of net cash provided by operating activities to EBITDA:				
Net cash provided by operating activities	$ 42.0	$ 26.3	$ 54.7	$ 66.1
Interest income	(1.7)	(1.2)	(5.1)	(3.7)
Interest expense	8.3	8.1	24.3	16.5
Earnings from equity method investments, net of distributions	(4.3)	2.2	(11.2)	(3.5)
Net changes in operating assets and liabilities	125.2	(13.1)	(28.2)	(23.1)
Other, net	(1.4)		(2.1)	0.4
EBITDA	$ 168.1	$ 22.3	$ 32.4	$ 52.7

We define distributable cash flow as net cash provided by or used in operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, proceeds from divestiture of assets, non-controlling interest on depreciation, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities (see Liquidity and Capital Resources for further definition of maintenance capital expenditures). Maintenance capital expenditures are capital expenditures made where we add on to or improve capital assets owned, or acquire or construct new capital assets, if such expenditures are made to maintain, including over the long term, our operating capacity or revenues. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing distributable cash flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices. Distributable cash flow is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research

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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.

Fair Value Measurements We utilize fair value to measure our financial instruments, including commodity and interest rate swap derivative assets and liabilities, as well as our short-term and restricted investments. Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

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

Level 2 inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 inputs are unobservable and considered significant to the fair value measurement.

A financial instrument s categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. We have a process for determining fair values, which are generally based upon quoted market prices, where available. In the event that listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an exit price methodology, in line with how we believe a marketplace participant would value that asset or liability. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, representing an accurate fair value for each instrument, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2007 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the nine months ended September 30, 2008 are the same as those described in our 2007 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, 2008 and 2007. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2008 vs. 2007		Variance Nine Months 2008 vs. 2007	
	2008 (a)	2007 (a)	2008 (a)	2007 (a)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Natural Gas Services (b)	$ 341.3	$ 118.6	$ 523.6	$ 306.3	$ 222.7	188%	$ 217.3	71%
Wholesale Propane Logistics	82.0	66.7	378.0	293.7	15.3	23%	84.3	29%
NGL Logistics	3.5	3.3	8.8	6.9	0.2	6%	1.9	28%
Total operating revenues	426.8	188.6	910.4	606.9	238.2	126%	303.5	50%
Gross margin (c):								
Natural Gas Services	174.9	22.0	26.2	47.3	152.9	695%	(21.1)	(45)%
Wholesale Propane Logistics	0.9	1.9	11.9	16.5	(1.0)	(53)%	(4.6)	(28)%
NGL Logistics	1.6	1.4	5.4	3.7	0.2	14%	1.7	46%
Total gross margin	177.4	25.3	43.5	67.5	152.1	601%	(24.0)	(36)%
Operating and maintenance expense	(10.2)	(8.1)	(31.8)	(21.0)	2.1	26%	10.8	51%
General and administrative expense	(6.0)	(5.4)	(16.8)	(17.1)	0.6	11%	(0.3)	(2)%
Other			1.5				1.5	*
Earnings from equity method investments (d)	8.1	10.8	38.7	23.6	(2.7)	(25)%	15.1	64%
Non-controlling interest in income	(1.2)	(0.3)	(2.7)	(0.3)	0.9	300%	2.4	800%
EBITDA (e)	168.1	22.3	32.4	52.7	145.8	654%	(20.3)	(39)%
Depreciation and amortization expense	(8.8)	(7.9)	(26.3)	(15.8)	0.9	11%	10.5	66%
Interest income	1.7	1.2	5.1	3.7	0.5	42%	1.4	38%
Interest expense	(8.3)	(8.1)	(24.3)	(16.5)	0.2	2%	7.8	47%
Net income (loss)	$ 152.7	$ 7.5	$ (13.1)	$ 24.1	$ 145.2	1,936%	$ (37.2)	(154)%
Operating data:								
Natural gas throughput (MMcf/d) (d)	704	770	797	735	(66)	(9)%	62	8%
NGL gross production (Bbls/d) (d)	18,783	22,570	22,241	21,083	(3,787)	(17)%	1,158	5%
Propane sales volume (Bbls/d)	11,445	13,014	19,934	21,539	(1,569)	(12)%	(1,605)	(7)%
NGL pipelines throughput (Bbls/d) (d)	31,881	30,837	32,681	28,890	1,044	3%	3,791	13%

* Percentage change is not meaningful.

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

(b)

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

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

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

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

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Three Months Ended September 30, 2008 vs. Three Months Ended September 30, 2007

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

- $147.6 million increase related to commodity derivative activity, of which a $0.5 million loss is included in sales of natural gas, NGLs and condensate, and a $148.1 million gain is included in gains from commodity derivative activity;

- $72.1 million increase attributable primarily to increased commodity prices, as well as higher natural gas and NGL sales volumes, primarily as a result of the MEG acquisition, partially offset by lower NGL and condensate production across our Northern Louisiana system as well as decreased volumes due to the impact of hurricanes, for our Natural Gas Services segment;

- $13.9 million increase attributable to increased propane prices, partially offset by decreased propane sales volumes as a result of lower demand due to higher prices for our Wholesale Propane Logistics segment; and

- $4.7 million increase in transportation, processing and other revenue, primarily attributable to the MEG acquisition in our Natural Gas Services segment; partially offset by

- $0.1 million decrease primarily due to decreases related to settlement of pipeline imbalances, partially offset by increased throughput volumes in our NGL Logistics segment.

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

- $152.9 million increase for our Natural Gas Services segment primarily due to increases related to commodity derivative activity, increased commodity prices, an increase in natural gas, NGL and condensate production as a result of the MEG acquisition, and increases due to changes in contract mix, partially offset by lower NGL and condensate production across our Northern Louisiana system as well as decreased volumes due to the impact of hurricanes; and

- $0.2 million increase for our NGL Logistics segment primarily due to increased throughput volumes; partially offset by

- $1.0 million decrease for our Wholesale Propane Logistics segment primarily as a result of unfavorable non-cash lower of cost or market inventory adjustments recognized in 2008 and favorable adjustments recognized in 2007, as well as lower propane sales volumes, partially offset by commodity derivative activity and higher per unit margins.

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

General and Administrative Expense General and administrative expense increased in 2008 compared to 2007, primarily as a result of increased fees paid to DCP Midstream, LLC under the Omnibus Agreement, primarily due to the MEG acquisition, partially offset by transaction costs incurred in 2007 related to acquisitions and decreased labor and benefits due to lower long-term incentive plan expenses.

Earnings from Equity Method Investments Earnings from equity method investments decreased in 2008 compared to 2007, due to decreased equity earnings of $2.0 million from East Texas, $0.5 million from Discovery and $0.2 million from Black Lake.

Non-Controlling Interest in Income Non-controlling interest in income reduced income in 2008 and 2007, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2008 compared to 2007, primarily as a result of the MEG acquisition.

Interest Expense Interest expense increased in 2008 compared to 2007, primarily as a result of financing the MEG acquisition in 2007.

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Nine Months Ended September 30, 2008 vs. Nine Months Ended September 30, 2007

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

- $267.5 million increase attributable primarily to increased commodity prices, as well as higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system as well as decreased volumes due to the impact of hurricanes, for our Natural Gas Services segment;

- $82.2 million increase attributable to increased propane prices and increased propane sales volumes due to the completion of the Midland terminal in May 2007, partially offset by decreased propane sales volumes as a result of milder weather in portions of our markets in 2008, supply disruptions and lower demand as a result of higher prices, for our Wholesale Propane Logistics segment;

- $16.0 million increase in transportation, processing and other revenue, primarily attributable to the MEG acquisition in our Natural Gas Services segment; and

- $1.1 million increase attributable primarily to increases related to settlement of pipeline imbalances and increased throughput volumes and for our NGL Logistics segment; partially offset by

- $63.3 million decrease related to commodity derivative activity, of which a $60.6 million loss is included in losses from commodity derivative activity and a $2.7 million loss is included in sales of natural gas, NGLs and condensate.

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

- $21.1 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity derivative activity and lower NGL and condensate production across our Northern Louisiana system as well as decreased volumes due to the impact of hurricanes, partially offset by an increase in natural gas, NGL and condensate production as a result of the MEG and Southern Oklahoma acquisitions, increased commodity prices and changes in contract mix; and

- $4.6 million decrease for our Wholesale Propane Logistics segment due to unfavorable non-cash lower of cost or market inventory adjustments recognized in 2008 and favorable adjustments recognized in 2007, lower per unit margins and lower sales volumes, partially offset by commodity derivative activity; partially offset by

- $1.7 million increase for our NGL Logistics segment attributable primarily to increases related to settlement of pipeline imbalances and increased throughput volumes.

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

General and Administrative Expense General and administrative expense decreased in 2008 compared to 2007, primarily attributable to transaction costs incurred in 2007 related to acquisitions and decreased labor and benefits due to lower long-term incentive plan expenses, partially offset by increased fees paid to DCP Midstream, LLC under the Omnibus Agreement, primarily due to acquisitions.

Other Other operating income increased due to a payment received during the second quarter of 2008 from a supplier to our Wholesale Propane Logistics segment related to the early termination of its supply agreement.

Earnings from Equity Method Investments Earnings from equity method investments increased in 2008 compared to 2007, due to increased equity earnings of $9.1 million from Discovery and $6.1 million from East Texas, partially offset by decreased equity earnings of $0.1 million from Black Lake.

Non-Controlling Interest in Income Non-controlling interest in income reduced income in 2008 and 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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Depreciation and Amortization Expense Depreciation and amortization expense increased in 2008 compared to 2007, primarily as a result of the 2007 acquisitions.

Interest Expense Interest expense increased in 2008 compared to 2007, primarily as a result of financing of the 2007 acquisitions.

Results of Operations Natural Gas Services Segment

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

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2008 vs. 2007		Variance Nine Months 2008 vs. 2007	
	2008 (a)	2007 (a)	2008 (a)	2007 (a)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 187.9	$ 116.3	$ 570.8	$ 306.0	$ 71.6	62%	$ 264.8	87%
Transportation, processing and other	12.0	7.3	34.0	19.6	4.7	64%	14.4	73%
Gains (losses) from commodity derivative activity (b)	141.4	(5.0)	(81.2)	(19.3)	146.4	*	61.9	321%
Total operating revenues	341.3	118.6	523.6	306.3	222.7	188%	217.3	71%
Purchases of natural gas and NGLs	166.4	96.6	497.4	259.0	69.8	72%	238.4	92%
Segment gross margin (c)	174.9	22.0	26.2	47.3	152.9	695%	(21.1)	(45)%
Operating and maintenance expense	(7.9)	(5.4)	(23.7)	(12.6)	2.5	46%	11.1	88%
Depreciation and amortization expense	(8.1)	(7.4)	(24.3)	(14.1)	0.7	9%	10.2	72%
Earnings from equity method investments (d)	7.8	10.3	37.8	22.6	(2.5)	(24)%	15.2	67%
Non-controlling interest in income	(1.2)	(0.3)	(2.7)	(0.3)	0.9	300%	2.4	800%
Segment net (loss) income	$ 165.5	$ 19.2	$ 13.3	$ 42.9	$ 146.3	762%	$ (29.6)	(69)%
Operating data:								
Natural gas throughput (MMcf/d) (d)	704	770	797	735	(66)	(9)%	62	8%
NGL gross production (Bbls/d) (d)	18,783	22,570	22,241	21,083	(3,787)	(17)%	1,158	5%

* Percentage change is not meaningful.

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

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

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

(d) Includes our proportionate share of the throughput volumes and earnings of East Texas and Discovery, 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, 2008 vs. Three Months Ended September 30, 2007

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

- $145.9 million increase related to commodity derivative activity, of which a $0.5 million loss is included in sales of natural gas, NGLs and condensate, and a $146.4 million gain is included in gains from commodity derivative activity. This activity includes cash settlements related to our investments in East Texas and Discovery of $4.7 million which reduced operating revenues;

- $65.5 million increase attributable to an increase in commodity prices;

- $6.6 million increase primarily attributable to higher natural gas and NGL sales volumes, primarily as a result of the MEG acquisition, partially offset by lower NGL and condensate production across our Northern Louisiana system as well as decreased volumes due to the impact of hurricanes; and

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$4.7 million increase in transportation, processing and other revenue primarily as a result of the MEG acquisition.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased in 2008 compared to 2007, primarily due to increased natural gas purchased volumes, primarily as a result of the MEG acquisition, and higher costs of raw natural gas supply, driven by higher commodity prices.

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

$145.9 million increase related to commodity derivative activity, as discussed in the Operating Revenues section above; and

$3.5 million increase due to increased commodity prices;

$2.4 million increase primarily attributable to an increase in natural gas, NGL and condensate production as a result of the MEG acquisition, partially offset by lower NGL and condensate production across our Northern Louisiana system as well as decreased volumes due to the impact of hurricanes; and

$1.1 million increase primarily attributable to changes in contract mix.

Operating and Maintenance Expense Operating and maintenance expense increased in 2008 compared to 2007, primarily as a result of the MEG acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2008 compared to 2007, primarily as a result of the MEG acquisition.

Earnings from Equity Method Investments Earnings from equity method investments decreased in 2008 compared to 2007, due to decreased equity earnings of $2.0 million from East Texas and decreased equity earnings of $0.5 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 net income of $7.8 million, due primarily to a $15.9 million decrease attributable to decreased natural gas throughput and NGL production, partially due to the effects of hurricanes, and increased operating and maintenance and general and administrative expense of $2.4 million, partially offset by an $8.8 million increase as a result of higher commodity prices and a $2.0 million increase due to increased fee-based revenue.

Increased equity earnings from Discovery were the result of an increase in Discovery s net income of $0.5 million, due primarily to $1.2 million higher NGL sales margins resulting primarily from increased per-unit margins on NGL sales volumes lowered by the impact of hurricanes, $2.5 million lower depreciation expense and $0.7 million lower general and administrative expense, substantially offset by $1.5 million lower transportation, gathering and fractionation revenue and $2.3 million higher operating and maintenance expense.

Non-Controlling Interest in Income Non-controlling interest in income reduced income in 2008 and 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.

NGL production and natural gas transported and/or processed decreased in 2008 compared to 2007, due primarily to decreased volumes across our Northern Louisiana system, and decreases at Discovery and East Texas, partially due to hurricanes, partially offset by increased volumes from the MEG acquisition.

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Nine Months Ended September 30, 2008 vs. Nine Months Ended September 30, 2007

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

- $175.0 million increase attributable to an increase in commodity prices;
- $92.5 million increase primarily attributable to higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system as well as decreased volumes due to the impact of hurricanes; and
- $14.4 million increase in transportation, processing and other revenue primarily as a result of the MEG acquisition; partially offset by
- $64.6 million decrease related to commodity derivative activity, $2.7 million of which is included as a loss in sales of natural gas, NGLs and condensate, and $61.9 million of which is included in losses from commodity derivative activity. This activity includes cash settlements related to our investments in East Texas and Discovery of $12.8 million which reduced operating revenues.

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

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

- $64.6 million decrease related to commodity derivative activity, as discussed in the Operating Revenues section above; partially offset by
- $27.4 million increase primarily attributable to an increase in natural gas, NGL and condensate production as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system as well as decreased volumes due to the impact of hurricanes;
- $12.6 million increase due to increased commodity prices; and
- $3.5 million increase primarily attributable to changes in contract mix.

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

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

Earnings from Equity Method Investments Earnings from equity method investments increased in 2008 compared to 2007, due to increased equity earnings of $9.1 million from Discovery and $6.1 million from East Texas. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

Increased equity earnings from Discovery were the result of an increase in Discovery s net income of $24.5 million, due primarily to $22.7 million higher NGL sales margins resulting from increased per-unit margins on NGL sales and plant inlet volumes that were reduced by hurricanes, a $3.5 million higher other income, and $1.7 million lower depreciation expense, partially offset by $2.2 million higher operating and maintenance expense and $1.7 million higher general and administrative expense.

Increased equity earnings from East Texas were the result of an increase in East Texas net income of $24.6 million, due primarily to a $29.8 million increase as a result of higher commodity prices, a $8.0 million increase due to increased fee-based revenue and a decrease in general and administrative expenses of $2.4 million, partially offset by a $10.4 million decrease due to decreased NGL production, partially due to the effects of hurricanes and other severe weather, and an increase in operating expenses of $4.5 million.

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Non-Controlling Interest in Income Non-controlling interest in income reduced income in 2008 and 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.

NGL production and natural gas transported and/or processed increased in 2008 compared to 2007, due primarily to increased volumes from the MEG and Southern Oklahoma acquisitions and increased volumes from East Texas, partially offset by decreased volumes from Pelico.

Results of Operations Wholesale Propane Logistics Segment

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

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2008 vs. 2007		Variance Nine Months 2008 vs. 2007	
	2008	2007	2008	2007	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of propane	$ 81.4	$ 67.5	$ 377.4	$ 295.2	$ 13.9	21%	$ 82.2	28%
Other		0.3	1.1	0.3	(0.3)	*	0.8	267%
Gains (losses) from commodity derivative activity	0.6	(1.1)	(0.5)	(1.8)	1.7	*	(1.3)	(72)%
Total operating revenues	82.0	66.7	378.0	293.7	15.3	23%	84.3	29%
Purchases of propane	81.1	64.8	366.1	277.2	16.3	25%	88.9	32%
Segment gross margin (a)	0.9	1.9	11.9	16.5	(1.0)	(53)%	(4.6)	(28)%
Operating and maintenance expense	(1.9)	(2.5)	(7.3)	(7.8)	(0.6)	(24)%	(0.5)	(6)%
Depreciation and amortization expense	(0.3)	(0.3)	(0.9)	(0.7)			0.2	29%
Other			1.5				1.5	*
Segment net (loss) income	$ (1.3)	$ (0.9)	$ 5.2	$ 8.0	$ (0.4)	(44)%	$ (2.8)	(35)%
Operating data:								
Propane sales volume (Bbls/d)	11,445	13,014	19,934	21,539	(1,569)	(12)%	(1,605)	(7)%

* Percentage change is not meaningful.

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

Three Months Ended September 30, 2008 vs. Three Months Ended September 30, 2007

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

$22.1 million increase attributable to higher propane prices; and

$1.7 million increase related to commodity derivative activity; partially offset by

$8.2 million decrease attributable to decreased propane sales volumes as a result of lower demand due to higher prices; and

$0.3 million decrease attributable to other fee revenue.

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

Segment Gross Margin Segment gross margin decreased in 2008 compared to 2007, primarily as a result of unfavorable non-cash lower of cost or market inventory adjustments of $3.0 million recognized in 2008 and favorable adjustments recognized in 2007, as well as lower propane sales volumes, partially offset by commodity derivative activity and higher per unit margins.

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

Nine Months Ended September 30, 2008 vs. Nine Months Ended September 30, 2007

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

- $103.7 million increase attributable to higher propane prices;
- $1.3 million increase related to commodity derivative activity; and
- $0.8 million increase attributable to other fee revenue; partially offset by
- $21.5 million decrease attributable to decreased propane sales volumes as a result of milder weather in portions of our markets in 2008, supply disruptions and lower demand as a result of higher prices, partially offset by increased propane sales volumes due to the completion of the Midland terminal in May 2007.

Purchases of Propane Purchases of propane increased in 2008 compared to 2007, primarily due to increased prices and the completion of the Midland terminal in May 2007, partially offset by decreased purchased volumes as a result of milder weather in portions of our markets in 2008 and supply disruptions.

Segment Gross Margin Segment gross margin decreased in 2008 compared to 2007, primarily as a result of unfavorable non-cash lower of cost or market inventory adjustments of $3.0 million recognized in 2008 and favorable adjustments recognized in 2007, lower per unit margins and lower sales volumes, partially offset by commodity derivative activity.

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

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

Results of Operations NGL Logistics Segment

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

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2008 vs. 2007		Variance Nine Months 2008 vs. 2007	
	2008	2007	2008	2007	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of NGLs	$ 1.9	$ 2.0	$ 4.2	$ 3.1	$ (0.1)	(5)%	$ 1.1	35%
Transportation, processing and other	1.6	1.3	4.6	3.8	0.3	23%	0.8	21%
Total operating revenues	3.5	3.3	8.8	6.9	0.2	6%	1.9	28%
Purchases of NGLs	1.9	1.9	3.4	3.2			0.2	6%
Segment gross margin (a)	1.6	1.4	5.4	3.7	0.2	14%	1.7	46%

Operating and maintenance expense	(0.4)	(0.2)	(0.8)	(0.6)	0.2	100%	0.2	33%
Depreciation and amortization expense	(0.4)	(0.2)	(1.1)	(1.0)	0.2	100%	0.1	10%
Earnings from equity method investment (b)	0.3	0.5	0.9	1.0	(0.2)	(40)%	(0.1)	(10)
Segment net income	$ 1.1	$ 1.5	$ 4.4	$ 3.1	$ (0.4)	(27)%	$ 1.3	42%
Operating data:								
NGL pipelines throughput (Bbls/d) (b)	31,881	30,837	32,681	28,890	1,044	3%	3,791	13%

(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.

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Three Months Ended September 30, 2008 vs. Three Months Ended September 30, 2007

Total Operating Revenues Total operating revenues increased in 2008 compared to 2007, primarily due to increased transportation and other fees and increased throughput volumes, partially offset by decreases related to settlement of pipeline imbalances.

Segment Gross Margin Segment gross margin increased in 2008 compared to 2007 primarily due to increased throughput volumes.

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

Nine Months Ended September 30, 2008 vs. Nine Months Ended September 30, 2007

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

Purchases of NGLs Purchases of NGLs increased in 2008 compared to 2007, due to increased throughput volumes and increases related to settlement of pipeline imbalances.

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

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

Liquidity and Capital Resources

Our predecessor s sources of liquidity, prior to their acquisition by us, included cash generated from operations and funding from DCP Midstream, LLC. Our predecessor s cash receipts were deposited in DCP Midstream, LLC s bank accounts and all cash disbursements were made from these accounts. Cash transactions for our predecessor were handled by DCP Midstream, LLC and 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 our equity method investments;
- borrowings under our revolving credit facility;
- cash realized from the liquidation of securities that are pledged under our term loan facility;
- issuance of additional partnership units;
- debt offerings;

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

We anticipate our more significant uses of resources to include:

- capital expenditures;
- contributions to our equity method investments to finance our share of their capital expenditures;

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- business and asset acquisitions;
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts; and
- quarterly distributions to our unitholders.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions for the next twelve months.

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

We have an existing credit agreement of $850.0 million, which is comprised of a revolver and term loan. As of September 30, 2008 we had revolver borrowings of $435.0 million. On October 1, 2008 we borrowed an additional $151.2 million to finance the Michigan acquisition. As of November 3, 2008, we had $586.2 million of outstanding indebtedness under our revolving credit facility.

Lehman Brothers Commercial Bank, or Lehman Brothers, is a lender in our Credit Agreement. Lehman Brothers has not funded its portion of our borrowing requests associated with the Michigan acquisition, and it is uncertain whether it will fund future borrowing requests. Accordingly, unless Lehman Brothers transfers their commitment to another commercial lender or we add another lender to the credit facility, we expect the availability of new borrowings under the existing $850.0 million credit agreement to be reduced by up to approximately $25.4 million. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the June 21, 2012 maturity date. As of November 3, 2008, we had approximately $238.0 million of liquidity, which includes available commitments under the Credit Agreement and excludes cash on hand.

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. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty s assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Prior to our initial public offering, DCP Midstream, LLC provided parental guarantees to certain counterparties to our commodity derivative instruments, totaling $63.0 million as of November 3, 2008. In July 2008, DCP Midstream, LLC provided additional parental guarantees to certain counterparties to our commodity derivative instruments, totaling $115.0 million as of November 3, 2008. As of November 3, 2008, we have letters of credit totaling $75.0 million. These parental guarantees and letters of credit reduce the amount of cash we may be required to post as collateral. As of November 3, 2008, we had no cash collateral posted with counterparties. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. Predetermined collateral thresholds for 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.

Working Capital Working capital is the amount by which current assets exceed current liabilities. Quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement, reduce our working capital. 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, cash collateral we may be required to post with counterparties to our commodity derivative instruments, 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 $22.7 million and a working capital deficit of $1.1 million as of September 30, 2008 and December 31, 2007, 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 were as follows:

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Millions)	
Net cash provided by operating activities	$ 54.7	$ 66.1
Net cash used in investing activities	$ (158.4)	$ (499.1)
Net cash provided by financing activities	$ 102.7	$ 446.4

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 paid net cash for settlements of our commodity derivative instruments during the nine months ended September 30, 2008 and 2007 totaling $37.8 million and $0.6 million, respectively.

We received cash of approximately $18.2 million from the counterparties to our commodity derivative instruments as a result of issuing letters of credit and DCP Midstream, LLC issuing parental guarantees to these counterparties.

We and our predecessor received cash distributions from equity method investments of $49.9 million and $27.1 million during the nine months ended September 30, 2008 and 2007, respectively. Distributions exceeded earnings by $11.2 million and $3.5 million for the nine months ended September 30, 2008 and 2007, respectively.

Net Cash Used in Investing Activities Net cash used in investing activities during the nine months ended September 30, 2008 was comprised of: (1) capital expenditures of $23.0 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities; (2) acquisition of the MEG subsidiaries of $10.9 million; (3) investments in Discovery of $1.9 million and East Texas of $3.8 million; and (4) net purchases of available-for-sale securities of $121.3 million; which were partially offset by (5) $2.5 million of proceeds from the sale of assets.

Net cash used in investing activities during the nine months ended September 30, 2007 was comprised primarily of: (1) asset acquisitions of $191.3 million; (2) acquisition of the MEG subsidiaries of $142.0 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.

We invested cash in equity method investments of $5.7 million and $4.3 million during the nine months ended September 30, 2008 and 2007, respectively, to fund our share of capital expansion projects.

Net Cash Provided by Financing Activities Net cash provided by financing activities during the nine months ended September 30, 2008 was comprised of (1) proceeds from debt of $432.0 million; (2) proceeds from sales of common limited partner units of $132.1 million, net of offering costs; (3) contributions from non-controlling interests of $2.8 million; and (4) net contributions from DCP Midstream, LLC of $1.4 million; which were partially offset by (5) payments of debt of $407.0 million; (6) distributions to our unitholders of $55.4 million; and (7) distributions to non-controlling interests of $3.2 million.

Net cash provided by financing activities during the nine months ended September 30, 2007, was comprised of (1) proceeds from debt of $569.0 million; and (2) the issuance of common units for $228.5 million, net of offering costs; partially offset by (3) payments of debt of $207.0 million; (4) distributions to our unitholders of $28.8 million; (5) changes in advances from DCP Midstream, LLC of $14.6 million; and (6) the excess of purchase price over the acquired assets attributable to payments related to our acquisition of Discovery, East Texas and the Swap of $90.4 million and our wholesale propane logistics business of $9.9 million.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 8 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. 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 made to increase our operating capacity or revenues (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).

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

We anticipate maintenance capital expenditures of $8.5 million and expansion capital expenditures of $164.4 million for the fourth quarter of 2008, including acquisitions. We may be required to contribute cash to East Texas and Discovery to cover our respective share of expansion capital expenditures at both East Texas and Discovery. DCP Midstream, LLC has agreed to reimburse us for our share of Discovery s capital expenditures for the Tahiti pipeline lateral. The board of directors may approve additional growth capital during the year, at their discretion.

Our capital expenditures, excluding acquisitions, totaled $23.0 million and $11.6 million, including maintenance capital expenditures of $3.7 million and $1.9 million, and expansion capital expenditures of $19.3 million and $9.7 million, during the nine months ended September 30, 2008 and 2007, respectively. In conjunction with the acquisition of our investments in East Texas and Discovery, we entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for 25% of certain East Texas capital expenditures, and will reimburse us for 40% of certain Discovery capital expenditures, as defined in the agreement, from July 1, 2007 through completion of the capital projects, for a period not to exceed three years. We also have an agreement with certain producers whereby these producers will reimburse us for certain capital projects completed by us. As a result, during the nine months ended September 30, 2008 and 2007, we had an increase in receivables of $0.2 million for both periods, related to collections of maintenance capital expenditures from DCP Midstream, LLC and producers. As a result, our total maintenance capital expenditures net of reimbursements totaled approximately $3.5 million and $1.7 million for the nine months ended September 30, 2008 and 2007, respectively.

In October 2008, we acquired Michigan Pipeline & Processing, LLC, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.1 million, subject to additional customary purchase price adjustments, plus up to an additional $15.0 million to the sellers depending on the earnings of the assets after a three-year period. We financed the acquisition with liquidation of a portion of our restricted investments. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller will pay us up to $1.5 million annually for up to nine years for this service; however, this agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. We hold a $25.0 million letter of credit to secure the seller s performance under this agreement and to secure the seller s indemnification obligation under the acquisition agreement. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

During the third quarter of 2008, we announced that Collbran Valley Gas Gathering, LLC, or Collbran, plans to invest approximately $150.0 million over a multi-year period to construct approximately 20 miles of 24-inch diameter gathering pipeline, and compression and liquids handling facilities, to support its Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. We are the operator and 70% owner of Collbran. The gathering system is designed to ultimately have throughput capacity of over 600 million cubic feet per day, or MMcf/d, and is supported by long-term acreage dedications from Plains Exploration & Production Company and Delta Petroleum Corporation, which own 25% and 5% of Collbran, respectively, and a long-term dedication from a subsidiary of Enterprise Products Partners LP covering gas that it has the right to gather from a specified, dedicated area within the Piceance Basin. Collbran will invest approximately $100.0 million in 2008 and 2009 to achieve throughput capacity of approximately 300 MMcf/d by the second quarter of 2009. The remaining investment in primarily compression equipment of approximately $50.0 million will be spent in 2010 through 2013 as production volumes increase, providing total throughput capacity in excess of 600 MMcf/d. We ultimately expect to invest approximately $105.0 million in this project, in proportion to our respective ownership interest.

We completed pipeline integrity testing at our Wyoming system during the second quarter of 2008 and commenced work on the pipeline to bring it back to normal operations. We are further upgrading our Wyoming system to assure future integrity, improve system reliability and reduce operating costs. We believe this work will be completed at a total cost of approximately $13.0 million, the majority of which is maintenance capital. Of the $13.0 million, approximately $1.6 million was incurred through the third quarter of 2008. We believe we will recover the costs of this work over time. The work on the pipeline will be completed in phases so that volumes will return to the system throughout the fourth quarter of 2008 and into the first quarter of 2009. We anticipate decreased operating revenues through the first quarter of 2009 as we complete this work.

During the third quarter of 2008, we announced plans, along with DCP Midstream, LLC, to invest approximately $56.0 million in East Texas to construct a gathering pipeline to support the East Texas system. Our interest in this pipeline is 25%. The pipeline is scheduled to be operational during the second quarter of 2009.

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

Annual maintenance capital expenditures in 2008 have increased as a result of a larger asset base due to the MEG and Southern Oklahoma acquisitions. We expect to fund future capital expenditures with restricted investments, funds generated from our operations, borrowings under our credit facility and the issuance of additional partnership units.

Cash Distributions to Unitholders Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders of $55.4 million during the nine months ended September 30, 2008, as compared to $28.8 million for the same period in 2007. 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 We have a 5-year credit agreement, or the Credit Agreement, consisting of a $630.0 million revolving credit facility and a $220.0 million term loan facility at September 30, 2008. The Credit Agreement matures on June 21, 2012. During the nine months ended September 30, 2008, we borrowed $252.0 million from our revolving credit facility for general corporate purposes and $30.0 million to fund a partial retirement of our term loan facility, and we repaid $377.0 million. During the nine months ended September 30, 2008, we borrowed $150.0 million from our term loan facility, and we repaid $30.0 million. As of September 30, 2008, the outstanding balance on the revolving credit facility was $435.0 million and the outstanding balance on the term loan facility was $220.0 million. As of September 30, 2008, the weighted-average effective interest rate was 5.19% per annum on the $435.0 million of outstanding debt under our revolving credit facility, and the interest rate was 2.59% on the $220.0 million of outstanding debt under our term loan facility. Subsequent to September 30, 2008, we borrowed $218.1 million from our revolving credit facility to repay a portion of our term loan facility and for general corporate purposes, repaid $150.0 million on our term loan facility to liquidate the restricted investments to fund the Michigan acquisition, and repaid $66.9 million on our revolving credit facility. As of November 3, 2008, the outstanding balances were $586.2 million and $70.0 million on our revolving credit and term loan facilities, respectively. The term loan is fully collateralized with restricted investments of $70.0 million.

Lehman Brothers has not funded its portion of our borrowing requests associated with the Michigan acquisition, and it is uncertain whether it will fund future borrowing requests. Accordingly, unless Lehman Brothers transfers their commitment to another commercial lender or we add another lender to the credit facility, we expect the availability of new borrowings under the existing $850.0 million credit agreement to be reduced by up to approximately $25.4 million. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the June 21, 2012 maturity date. As of November 3, 2008, we had approximately $238.0 million of liquidity, which includes available commitments under the Credit Agreement and excludes cash on hand.

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. Our restricted investments totaled $70.4 million as of November 3, 2008. Any portion of the term loan balance may be repaid at any time, and we would then have access to a corresponding amount of the collateral securities. Upon any prepayment of term loan borrowings, the amount of our revolving credit facility will automatically increase to the extent that the repayment of our term loan facility is made in connection with an acquisition of assets in the midstream energy business. The unused portion of the revolving credit facility may be used for general corporate purposes and for letters of credit. At September 30, 2008 and December 31, 2007, we had outstanding letters of credit of $0.3 million and $0.2 million under the Credit Agreement, respectively.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of September 30, 2008, is as follows:

		Payments Due by Period			
	Total	Remainder of 2008	2009-2010	2011-2012	2013 and Thereafter
			(Millions)		
Long-term debt (a)	$ 729.4	$ 5.6	$ 45.1	$ 678.7	$
Operating lease obligations	47.3	2.9	17.2	14.2	13.0
Purchase obligations (b)	1,266.0	121.6	467.0	351.2	326.2
Other long-term liabilities (c)	8.6		0.3	0.3	8.0
Total	$ 2,051.3	$ 130.1	$ 529.6	$ 1,044.4	$ 347.2

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

(b) Purchase obligations include $16.9 million of purchase orders for capital expenditures and $1,249.1 million of various non-cancelable commitments to purchase physical quantities of commodities in future periods. For contracts where the price paid is based on an index, the amount is based on the forward market prices at September 30, 2008. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the condensed consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in 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 of the underlying commodity. In addition, many of our gas purchase contracts include short and long term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(c) Other long-term liabilities include $7.9 million of asset retirement obligations and $0.7 million of environmental reserves recognized in the September 30, 2008 condensed consolidated balance sheet.

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

Recent Accounting Pronouncements

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

FASB Staff Position, or FSP, No. SFAS 142-3 Determination of the Useful Life of Intangible Assets, **or FSP 142-3** In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3 on our consolidated results of operations, cash flows or financial position.

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

SFAS No. 160 Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51, **or SFAS 160** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. We are assessing the impact of the adoption SFAS 160, and believe that it will not have a significant impact on our consolidated results of operations, cash flows or financial position. Any required changes to presentation and disclosures will be made in our first filing following the effective date of this standard.

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

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

SFAS No. 157, Fair Value Measurements**, or SFAS 157** In September 2006, the FASB issued SFAS 157, which was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;

establishes a framework for measuring fair value;

establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;

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

significantly expands the disclosure requirements around instruments measured at fair value.

The adoption of this standard resulted in us making slight changes to our valuation methodologies to incorporate the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we have recorded a transition adjustment of approximately $5.8 million as an increase to earnings and approximately $1.3 million as an increase to accumulated other comprehensive income during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While, we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we have not assessed the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities.

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

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

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 2007 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, as these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC s corporate credit policy. DCP Midstream, LLC s corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC s credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Interest Rate Risk

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

We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $425.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swaps re-price prospectively approximately every 90 days. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. At September 30, 2008, the effective weighted-average interest rate on our $435.0 million of outstanding revolver debt was 5.19%, taking into account the $425.0 million of indebtedness with designated interest rate swaps.

Based on the annualized unhedged borrowings under our credit facility of $230.0 million as of September 30, 2008, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $1.2 million annualized increase or decrease in interest expense.

Commodity Price Risk

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

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

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

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

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

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

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income) (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 5.7
Crude oil prices	$ 5.00	Barrel	$ 19.0

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

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 1.1
NGL prices	$ 0.10	Gallon	$ 2.6
Crude oil prices	$ 5.00	Barrel	$ 0.2

Based on our current contract mix, we believe that during the remainder of 2008 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 Commodity Cash Flow Protection Activities in our 2007 Form 10-K for more information about 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.

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 residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close correlation.

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

Item 4. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

Our management, including the Chief Executive Officer and the Chief Financial Officer, of DCP Midstream GP, LLC, has 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 and 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 Executive Officer and the Chief Financial 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, 2008 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 16, Commitments and Contingent Liabilities, included in Item 8 of our 2007 Form 10-K, 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 2007 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 2007 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 are new or modified risk factors that should be read in conjunction with the risk factors disclosed in our 2007 Form 10-K:

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

The capital markets have recently experienced volatility, uncertainty and interventions by various governments around the globe. This turmoil in the global capital markets has caused significant financial uncertainty. As further described in this Form 10-Q, one of the lenders to our 5-year credit agreement, or the Credit Agreement, recently failed to fund under that agreement. If that lender continues to fail to fund under the Credit Agreement, it would result in a reduction in the available borrowings under the Credit Agreement up to approximately $25.4 million. If additional lenders under the Credit Agreement were to fail to fund their share of the Credit Agreement, our available borrowings could be further reduced. In addition, our borrowing capacity may be further limited by the Credit Agreement s financial covenant requirements. Our access to funds under the Credit Agreement is dependent on the ability of the lenders that are party to the Credit Agreement to meet their funding obligations. Those lenders may not be able to meet their funding commitments if they experience shortages of capital and liquidity.

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

Our derivative activities and the application of fair value measurements may have a material adverse effect on our earnings, profitability, cash flows, liquidity and financial condition.

We are exposed to risks associated with fluctuations in commodity prices. The extent of our commodity price risk is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have primarily entered into derivative financial instruments relating to the future price of crude oil. If the price relationship between NGLs and crude oil changes, our commodity price risk may increase. Furthermore, we have entered into derivative transactions related to only a portion of the volume of our expected natural gas supply and production of NGLs and condensate from our processing plants; as a result, we will continue to have direct commodity price risk to the open portion. Our actual future production may be significantly higher or

lower than we estimate at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimate, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, reducing our liquidity.

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

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

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

The counterparties to our derivative instruments may require us to post collateral in the event that our potential payment exposure exceeds a predetermined collateral threshold. As of November 3, 2008, DCP Midstream, LLC provided parental guarantees to certain counterparties to our commodity derivative instruments totaling $178.0 million and we had letters of credit totaling $75.0 million, which reduce the amount of cash we may be required to post as collateral. As of November 3, 2008, we had no cash collateral posted with counterparties. Depending on the movement in commodity prices, the amount of collateral posted may increase, reducing our liquidity.

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

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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on November 10, 2008.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP

its General Partner

By: DCP Midstream GP, LLC

its General Partner

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

By: /s/ Angela A. Minas
Name: Angela A. Minas
Title: Vice President and Chief Financial Officer

(Principal Financial Officer)

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