DCP Midstream Partners, LP
Form 10-Q
May 11, 2009
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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 March 31, 2009

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ 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 May 4, 2009, there were outstanding 28,233,183 common limited partner units and 3,500,000 Class D units.

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DCP MIDSTREAM PARTNERS, LP

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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/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, 2008, as well as the following risks and uncertainties:

- 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;
- general economic, market and business conditions;
- the level and success of natural gas drilling around our assets, the level of gas production volumes 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 our ability to comply with the covenants to our credit agreement;
- 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;

- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of the insurance to cover our losses;

- 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; and

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

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)

	March 31, 2009	December 31, 2008
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12.0	$ 48.0
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.7 million and $0.6 million, respectively	35.4	43.6
Affiliates	36.3	36.8
Inventories	18.0	20.9
Unrealized gains on derivative instruments	15.8	15.4
Other	0.8	0.5
Total current assets	118.3	165.2
Restricted investments	60.2	60.2
Property, plant and equipment, net	646.5	629.3
Goodwill	89.3	88.8
Intangible assets, net	46.6	47.7
Equity method investments	174.5	175.4
Unrealized gains on derivative instruments	9.5	8.6
Other long-term assets	4.6	4.8
Total assets	$ 1,149.5	$ 1,180.0
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 32.2	$ 44.8
Affiliates	27.9	33.6
Unrealized losses on derivative instruments	18.4	17.7
Accrued interest payable	0.9	1.3
Other	26.4	27.4
Total current liabilities	105.8	124.8
Long-term debt	645.0	656.5
Unrealized losses on derivative instruments	26.3	26.0
Other long-term liabilities	8.7	8.9
Total liabilities	785.8	816.2

Commitments and contingent liabilities

Equity:		
Common unitholders (28,233,183 and 24,661,754 units issued and outstanding, respectively)	376.4	429.0
Subordinated unitholders (0 and 3,571,429 convertible units issued and outstanding, respectively)		(54.6)
General partner interest	(4.8)	(4.8)
Accumulated other comprehensive loss	(40.5)	(40.5)
Total partners equity	331.1	329.1
Noncontrolling interests	32.6	34.7
Total equity	363.7	363.8
Total liabilities and equity	$ 1,149.5	$ 1,180.0

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 March 31, 2009	2008
	(Millions, except per unit amounts)	
Operating revenues:		
Sales of natural gas, propane, NGLs and condensate	$ 142.1	$ 251.8
Sales of natural gas, propane, NGLs and condensate to affiliates	75.6	110.9
Transportation, processing and other	12.4	5.8
Transportation, processing and other to affiliates	3.5	6.3
Gains (losses) from commodity derivative activity, net	7.7	(37.8)
(Losses) gains from commodity derivative activity, net affiliates	(0.7)	0.7
Total operating revenues	240.6	337.7
Operating costs and expenses:		
Purchases of natural gas, propane and NGLs	104.3	247.9
Purchases of natural gas, propane and NGLs from affiliates	78.5	81.8
Operating and maintenance expense	9.2	10.6
Depreciation and amortization expense	10.4	8.5
General and administrative expense	2.6	2.6
General and administrative expense affiliates	3.2	2.9
Total operating costs and expenses	208.2	354.3
Operating income (loss)	32.4	(16.6)
Interest income	0.2	1.6
Interest expense	(7.3)	(8.1)
(Losses) earnings from equity method investments	(2.2)	17.2
Income (loss) before income taxes	23.1	(5.9)
Income tax expense	(0.1)	
Net income (loss)	23.0	(5.9)
Net income attributable to noncontrolling interests	(0.9)	(0.6)
Net income (loss) attributable to partners	22.1	(6.5)
General partner interest in net income or net loss	(3.2)	(2.6)
Net income (loss) allocable to limited partners	$ 18.9	$ (9.1)
Net income (loss) per limited partner unit basic and diluted	$ 0.67	$ (0.36)
Weighted-average limited partner units outstanding basic and diluted	28.2	24.9

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 March 31, 2009	Three Months Ended March 31, 2008
	(Millions)	
Net income (loss)	$ 23.0	$ (5.9)
Other comprehensive loss:		
Reclassification of cash flow hedges into earnings	4.5	0.4
Net unrealized losses on cash flow hedges	(4.5)	(13.7)
Total other comprehensive loss		(13.3)
Total comprehensive income (loss)	23.0	(19.2)
Total comprehensive income attributable to noncontrolling interests	(0.9)	(0.6)
Total comprehensive income (loss) attributable to partners	$ 22.1	$ (19.8)

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31, 2009	2008
	(Millions)	
OPERATING ACTIVITIES:		
Net income (loss)	$ 23.0	$ (5.9)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization expense	10.4	8.5
Distributions from equity method investments, net of losses and earnings, respectively	2.7	2.0
Other, net	0.1	(0.5)
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:		
Accounts receivable	8.4	21.3
Inventories	2.9	6.2
Net unrealized losses on derivative instruments	(0.2)	28.6
Accounts payable	(18.3)	(43.3)
Accrued interest	(0.4)	(0.6)
Other current assets and liabilities	(2.3)	8.9
Other long-term assets and liabilities	0.3	(0.1)
Net cash provided by operating activities	26.6	25.1
INVESTING ACTIVITIES:		
Capital expenditures	(25.7)	(9.2)
Acquisition of Michigan Pipeline & Processing, LLC	(0.3)	
Acquisition of subsidiaries of Momentum Energy Group, Inc		(10.9)
Investments in equity method investments	(1.8)	(2.8)
Purchases of available-for-sale securities	(1.0)	(389.0)
Proceeds from sales of available-for-sale securities	0.8	270.3
Net cash used in investing activities	(28.0)	(141.6)
FINANCING ACTIVITIES:		
Proceeds from debt		255.0
Payments of debt	(11.5)	(230.0)
Proceeds from issuance of common units, net of offering costs		132.3
Distributions to unitholders and general partner	(20.1)	(16.2)
Distributions to noncontrolling interests	(3.9)	
Contributions from noncontrolling interests	0.9	2.1
Contributions from DCP Midstream, LLC		1.9
Net cash (used in) provided by financing activities	(34.6)	145.1
Net change in cash and cash equivalents	(36.0)	28.6
Cash and cash equivalents, beginning of period	48.0	24.5

Cash and cash equivalents, end of period	$ 12.0	$ 53.1

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Unaudited)

	Partners Equity					
	Common Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
				(Millions)		
Balance, January 1, 2009	$ 429.0	$ (54.6)	$ (4.8)	$ (40.5)	$ 34.7	$ 363.8
Conversion of subordinated units to common units	(52.1)	52.1				
Distributions to unitholders and general partner	(14.8)	(2.1)	(3.2)			(20.1)
Contributions from noncontrolling interests					0.9	0.9
Distributions to noncontrolling interests					(3.9)	(3.9)
Comprehensive income:						
Net income	14.3	4.6	3.2		0.9	23.0
Reclassification of cash flow hedges into earnings				4.5		4.5
Net unrealized losses on cash flow hedges				(4.5)		(4.5)
Total comprehensive income	14.3	4.6	3.2		0.9	23.0
Balance, March 31, 2009	$ 376.4	$	$ (4.8)	$ (40.5)	$ 32.6	$ 363.7

	Partners Equity					
	Common Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
				(Millions)		
Balance, January 1, 2008	$ 308.8	$ (120.1)	$ (5.4)	$ (14.9)	$ 26.9	$ 195.3
Conversion of subordinated units to common units	(66.4)	66.4				
Distributions to unitholders and general partner	(9.6)	(4.1)	(2.0)			(15.7)
Contributions from noncontrolling interests					2.1	2.1
Contributions from unitholders	1.8					1.8
Issuance of 4,250,000 common units	132.3					132.3
Comprehensive income:						
Net (loss) income	(2.4)	(5.8)	1.7		0.6	(5.9)
Reclassification of cash flow hedges into earnings				0.4		0.4
Net unrealized losses on cash flow hedges				(13.7)		(13.7)
Total comprehensive income	(2.4)	(5.8)	1.7	(13.3)	0.6	(19.2)

Balance, March 31, 2008	$ 364.5	$	(63.6)	$	(5.7)	$	(28.2)	$	29.6	$	296.6

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Description of Business and Basis of Presentation

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

We are a Delaware master limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our Northern Louisiana system; our Southern Oklahoma system; our limited liability company interests in DCP East Texas Holdings, LLC, or East Texas, and Discovery Producer Services LLC, or Discovery; our Wyoming system and a 70% interest in our Colorado system; our Michigan systems (acquired in October 2008); 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 results of operations of our Michigan systems have been included in the condensed consolidated financial statements since October 1, 2008, the date of acquisition.

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP.

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 2008 Form 10-K.

2. Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or 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. We adopted the provisions of SFAS 161 effective January 1, 2009, and have included all required disclosures in this filing. SFAS 161 impacts only disclosures so there was no effect on our consolidated results of operations, cash flows or financial position as a result of adoption.

***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. We adopted SFAS 160 effective January 1, 2009, which required retrospective restatement of our condensed consolidated financial statements for all periods presented in this filing. As a result of adoption, we have reclassified our noncontrolling interest on our condensed consolidated balance sheets, from a component of liabilities to a component of equity and have also reclassified net income attributable to noncontrolling interest on our condensed consolidated statements of operations, to below net income for all periods presented. Furthermore, we have displayed the portion of other comprehensive income that is attributable to the noncontrolling interest within our condensed consolidated statements of comprehensive income. We also added a rollforward of the noncontrolling interest within our condensed consolidated statements of changes in equity.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

***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 subsequent to January 1, 2009 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. We adopted SFAS 141(R) effective January 1, 2009, and will account for all transactions with closing dates subsequent to adoption in accordance with the provisions of this standard.

***SFAS No. 157 Fair Value Measurements*, or SFAS 157** In September 2006, the FASB issued SFAS 157, which we adopted on January 1, 2008. Pursuant to FASB Staff Position, or FSP, 157-2, the FASB issued a partial deferral, ending on December 31, 2008, of the implementation of SFAS 157 as it relates to all nonfinancial assets and liabilities where fair value is the required measurement attribute by other accounting standards. Effective January 1, 2009, we adopted SFAS 157 for all nonfinancial assets and liabilities. There was no effect on our consolidated results of operations, cash flows, or financial position, and we have included all required disclosures as a result of the adoption of this standard relative to nonfinancial assets and liabilities. The provisions of SFAS 157 will be applied at such time a fair value measurement of a nonfinancial asset or nonfinancial liability is required, which may result in a fair value that is different than would have been calculated prior to the adoption of SFAS 157.

***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 an intangible asset. We adopted FSP 142-3 on January 1, 2009. As a result of acquisitions, we have intangible assets for customer contracts and related relationships in our condensed consolidated balance sheets. Generally, costs to renew or extend such contracts are not significant, and are expensed to the condensed consolidated statements of operations as incurred. During the current quarter, there were no contracts that were recognized as intangible assets that were renewed or extended.

***FSP No. SFAS 157-4 Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* or FSP 157-4** In April 2009, the FASB issued FSP 157-4, which provides additional guidance on the valuation of assets or liabilities that are held in markets that have seen a significant decline in activity. While this FSP does not change the overall objective of determining fair value, it emphasizes that in markets with significantly decreased activity and the appearance of non-orderly transactions, an entity may employ multiple valuation techniques, to which significant adjustments may be required, to determine the most appropriate fair value. Generally, for instruments that we measure at fair value, we do not transact within markets that have seen either a significant change in the volume of activity, or in the relevance of the related pricing, which would affect the validity and reliability of our fair value measurements. This FSP becomes effective for us for annual and interim periods beginning after June 30, 2009. We are currently in the process of assessing the impact of this FSP on our operations, but we do not expect there to be a significant effect on our consolidated results of operations, cash flows or financial position as a result of adoption.

***FSP No. SFAS 141(R)-1 Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies,* or FSP 141(R)-1** In April 2009, the FASB issued FSP 141(R)-1, which provides additional guidance on the valuation of assets and liabilities assumed in a business combination that arise from contingencies, which would otherwise be subject to the provisions of SFAS No. 5 Accounting for Contingencies, or SFAS 5. This FSP emphasizes the guidance set forth in SFAS 141(R) that assets and liabilities assumed in a business combination that have an estimated fair value should be recorded at the time of acquisition. Assets and liabilities where the fair value may not be determinable during the measurement period will continue to be recognized pursuant to SFAS 5. This FSP becomes effective for us for business combinations with closing dates subsequent to January 1, 2009. During the first quarter of 2009 we did not have any transactions that were accounted for as business combinations. We will account for any business combinations with closing dates subsequent to the effective date in accordance with this new guidance.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

FSP No. SFAS 107-1 and APB 28-1 Interim Disclosures about Fair Value of Financial Instruments This FSP was issued in April 2009, and requires disclosure of summarized financial information for financial instruments accounted for under SFAS No. 107 Disclosures about Fair Value of Financial Instruments, or SFAS 107. We have instruments that are subject to the fair value disclosure requirements of SFAS 107, and will be subject to the revised disclosure provisions of this FSP. This FSP becomes effective for us for annual and interim periods beginning after June 30, 2009, and we will begin providing this information in our interim and annual statements subsequent to the effective date of this FSP.

FSP No. SFAS 115-2 and SFAS 124-2 Recognition and Presentation of Other-Than-Temporary Impairments This FSP was issued in April 2009, and amends the other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This FSP becomes effective for us for annual and interim periods beginning after June 30, 2009, and we will begin providing this information in our interim and annual statements subsequent to the effective date of this FSP. We are currently in the process of evaluating the impact of this FSP on our operations, but do not believe that it will have a significant impact on our consolidated results of operations, cash flows or financial position.

***Emerging Issues Task Force, or EITF, 08-6 Equity Method Investment Accounting Considerations*, or EITF 08-6** In November 2008 the EITF issued EITF 08-6. Although the issuance of SFAS 141(R) and SFAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee s issuance of shares should be accounted for; and d) how to account for a change in an investment from the equity method to the cost method. This issue became effective for us on January 1, 2009, and although it has not impacted the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

***EITF 07-4 Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships* or EITF 07-4** In March 2008, the EITF issued EITF 07-4. This issue seeks to improve the comparability of earnings per unit, or EPU, calculations for master limited partnerships with incentive distribution rights in accordance with FASB Statement No. 128 and its related interpretations. We adopted EITF 07-4 effective January 1, 2009. As a result of adopting EITF 07-4, undistributed earnings or losses are reduced or increased, respectively, by the amount of available cash that was generated during the current period, and undistributed earnings are no longer allocated to our general partner with respect to its incentive distribution rights, as our partnership agreement specifically limits incentive distributions to available cash. EITF 07-4 is applied retrospectively for all periods. We have retrospectively restated our previously disclosed net income (loss) per limited partner unit, or LPU, and related disclosures, within this filing. As a result of adoption, net loss per LPU increased from $(0.33) per unit to $(0.36) per unit for the three months ended March 31, 2008.

3. Acquisitions

Gathering and Compression Assets

On October 1, 2008, we acquired Michigan Pipeline & Processing, LLC, or MPP, 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. The results of MPP s operations have been included in the condensed consolidated financial statements, within the Natural Gas Services segment, since that date. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.4 million. 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 through utilization of our credit facility. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay up to $1.5 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments may reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. Certain of these performance criteria were satisfied and, as a result, the amount was reduced to approximately $0.8 million per year as of March 31, 2009. We initially held 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; however as a result of the satisfaction of certain performance conditions, this amount was reduced to approximately $20.0 million as of March 31, 2009. The fees under our omnibus agreement with DCP Midstream, LLC increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Under the purchase method of accounting, the assets and liabilities of MPP were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $7.2 million. The goodwill amount recognized relates primarily to projected growth from new customers. The values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained, which when finalized may result in material adjustments. The purchase price allocation is as follows:

	(Millions)
Cash	$ 1.7
Accounts receivable	1.9
Other assets	0.1
Other long term assets	3.9
Property, plant and equipment	116.1
Goodwill	7.2
Intangible assets	19.6
Other liabilities	(0.5)
Noncontrolling interest in joint venture	(1.6)
Total purchase price allocation	$ 148.4

4. 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 has issued parental guarantees, totaling $43.0 million at March 31, 2009, to certain counterparties to our commodity derivative instruments. During the three months ended March 31, 2009 and 2008, we incurred $2.4 million for both periods for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $0.7 million and $0.5 million, respectively.

Other Agreements and Transactions with DCP Midstream, LLC

On February 25, 2009, we entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC will contribute an additional 25.1% interest in East Texas to us in exchange for 3,500,000 Class D units, providing us with a 50.1% interest in East Texas. This transaction closed in April 2009. Subsequent to this transaction we will consolidate our 50.1% interest in East Texas and we will consequently no longer disclose East Texas as an equity method investment.

We sell a portion of our residue gas and NGLs to, purchase 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 owns certain assets and is party to certain contractual relationships around our Pelico system that are periodically used for the benefit of Pelico. DCP Midstream, LLC is able to source natural gas upstream of Pelico and deliver it to us and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. Pelico has certain contractual relationships that define how natural gas is bought and sold between us and DCP Midstream, LLC.

In January 2009, we amended our Pelico gas purchase and sales agreement with DCP Midstream, LLC. As a result of the amendment, our purchases from DCP Midstream, LLC occur upstream of Pelico, rather than at the inlet of Pelico. We assumed from DCP Midstream, LLC a firm transportation agreement with an affiliate to transport our natural gas purchases from DCP Midstream, LLC to Pelico. In addition, historically, the sales price of a portion of the natural gas we sold to DCP Midstream, LLC was determined based on the price at which we purchased the natural gas from DCP Midstream, LLC plus a portion of the index differential between upstream sources to certain downstream indices with a maximum and minimum differential. The pricing methodology has changed as described below:

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For volumes supplied to certain industrial end users and any volumes in excess of the on-system demand, DCP Midstream, LLC will purchase natural gas from us and sell it to certain industrial end users, or transport it to sales points at an index-based price, less contractually agreed-to marketing fees. We generally report revenues associated with these activities gross in the condensed consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates.

DCP Midstream, LLC was a significant customer during the three months ended March 31, 2009 and 2008.

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 did not make capital contributions to us during the three months ended March 31, 2009 and made $1.6 million of capital contributions to us during the three months ended March 31, 2008, to reimburse us for these capital projects.

DCP Midstream, LLC has issued additional parental guarantees outside of the Omnibus Agreement, totaling $40.0 million at March 31, 2009, 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 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. This 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 provided under a contract with a third party that was terminated for non-performance 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, and 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 $0.2 million and $0.9 million of capital reimbursements during the three months ended March 31, 2009 and 2008, respectively.

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 March 31, 2009	Three Months Ended March 31, 2008
	(Millions)	
DCP Midstream, LLC:		
Sales of natural gas, propane, NGLs and condensate	$ 75.6	$ 110.1
Transportation, processing and other	$ 1.2	$ 5.5
Purchases of natural gas, propane and NGLs	$ 43.1	$ 75.2
(Losses) gains from commodity derivative activity, net	$ (0.7)	$ 0.7
General and administrative expense	$ 3.1	$ 2.9
Interest expense	$ 0.1	$
Spectra Energy:		
Sales of natural gas, propane, NGLs and condensate	$	$ 0.2
Purchases of natural gas, propane and NGLs	$ 33.7	$
ConocoPhillips:		
Sales of natural gas, propane, NGLs and condensate	$	$ 0.6
Transportation, processing and other	$ 2.3	$ 0.8
Purchases of natural gas, propane and NGLs	$ 1.3	$ 6.6
General and administrative expense	$ 0.1	$
Unconsolidated affiliates:		
Purchases of natural gas, propane and NGLs	$ 0.4	$

We had balances with affiliates as follows:

	March 31, 2009	December 31, 2008
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 32.5	$ 30.3
Accounts payable	$ 27.0	$ 27.9
Unrealized losses on derivative instruments current	$ (1.2)	$ (1.2)
Spectra Energy:		
Accounts receivable	$ 2.4	$ 4.0
Accounts payable	$ 0.3	$ 5.3
ConocoPhillips:		
Accounts receivable	$ 1.4	$ 2.5
Accounts payable	$ 0.2	$ 0.4
Unconsolidated affiliates:		
Accounts payable	$ 0.4	$

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Equity Method Investments

The following table summarizes our equity method investments:

	Percentage of Ownership as of March 31, 2009 and December 31, 2008	Carrying Value as of March 31, 2009	Carrying Value as of December 31, 2008
		(Millions)	
Discovery Producer Services LLC	40%	$ 103.8	$ 105.0
DCP East Texas Holdings, LLC	25%	64.3	63.9
Black Lake Pipe Line Company	45%	6.2	6.3
Other	50%	0.2	0.2
Total equity method investments		$ 174.5	$ 175.4

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $39.1 million and $39.7 million at March 31, 2009 and December 31, 2008, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

There was a deficit between the carrying amount of the investment and the underlying equity of Black Lake of $6.0 million at March 31, 2009 and December 31, 2008, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

Earnings from equity method investments were as follows:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(Millions)	
Discovery Producer Services LLC	$ (1.5)	$ 10.2
DCP East Texas Holdings, LLC	(1.1)	6.6
Black Lake Pipe Line Company and other	0.4	0.4
Total (losses) earnings from equity method investments	$ (2.2)	$ 17.2
Distributions from equity method investments	$ 0.5	$ 19.2
Distributions from equity method investments, net of losses and earnings, respectively	$ 2.7	$ 2.0

The following summarizes financial information of our equity method investments:

	Three Months Ended March 31,	
	2009	2008
	(Millions)	
Statements of operations:		
Operating revenue	$ 65.4	$ 230.5
Operating expenses	$ 74.0	$ 184.6
Net (loss) income	$ (8.9)	$ 49.7

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	March 31, 2009	December 31, 2008
	(Millions)	
Balance sheets:		
Current assets	$ 93.7	$ 104.3
Long-term assets	679.1	646.3
Current liabilities	(99.9)	(84.4)
Long-term liabilities	(23.4)	(22.4)
Net assets	$ 649.5	$ 643.8

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.

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 less active markets 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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.

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 input that requires the highest degree of judgment in the determination of the instrument s fair value. 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.

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.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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. The swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR 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 and money market instruments. 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 are priced using a yield curve for similarly rated instruments, and are classified within Level 2. As of March 31, 2009, 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.

Nonfinancial Assets and Liabilities

We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3, in the event that we were required to measure and record such assets at fair value within our consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations on our leased property, plant and equipment. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following table presents the financial instruments carried at fair value as of March 31, 2009:

	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 (a)	$	$ 0.2	$	$ 0.2
Commodity derivatives (b)	$	$ 14.8	$ 1.0	$ 15.8
Long-term assets:				
Restricted investments	$	$ 60.2	$	$ 60.2
Commodity derivatives (c)	$	$ 7.8	$ 1.7	$ 9.5
Current liabilities (d):				
Commodity derivatives	$	$ (1.2)	$	$ (1.2)
Interest rate derivatives	$	$ (17.2)	$	$ (17.2)
Long-term liabilities (e):				
Commodity derivatives	$	$ (3.3)	$ (0.3)	$ (3.6)
Interest rate derivatives	$	$ (22.7)	$	$ (22.7)

(a) Included in other current assets in our condensed consolidated balance sheets.

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

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

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

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

Changes in Level 3 Fair Value Measurements

The tables below illustrate 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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(Unaudited)

	Balance at December 31, 2008	Net Realized and Unrealized Gains (Losses) Included in Earnings	Transfers In/ Out of Level 3 (a)	Purchases, Issuances and Settlements, Net	Balance at March 31, 2009	Net Unrealized Gains (Losses) Still Held Included in Earnings (b)
	(Millions)					
Commodity derivatives:						
Current assets	$ 0.3	$ 0.8	$	$ (0.1)	$ 1.0	$ 0.8
Long-term assets	$ 1.7	$	$	$	$ 1.7	$
Long-term liabilities	$	$ (0.3)	$	$	$ (0.3)	$ (0.3)

	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 March 31, 2008	Net Unrealized Gains (Losses) Still Held Included in Earnings (b)
	(Millions)					
Commodity derivatives:						
Current assets	$ 0.2	$	$ (0.2)	$	$	$
Long-term assets	$ 1.5	$ (0.3)	$	$	$ 1.2	$ (0.3)
Current liabilities	$ (1.6)	$ (0.5)	$	$ 0.8	$ (1.3)	$ (0.5)
Long-term liabilities	$ (0.2)	$	$ 0.2	$	$	$

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

(b) Represents the amount of total gains or losses for the period, included in gains or 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 March 31, 2009 and 2008.

7. Debt

Long-term debt was as follows:

December 31, 2008

	March 31, 2009	
	(Millions)	
Revolving credit facility, weighted-average interest rate of 1.57% and 2.08%, respectively, due June 21, 2012 (a)	$ 585.0	$ 596.5
Term loan facility, interest rate of 0.65% and 1.54%, respectively, due June 21, 2012 (b)	60.0	60.0
Total long-term debt	$ 645.0	$ 656.5

(a) $575.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.26% to 5.19%, for a net effective rate of 4.59% on the $585.0 million of outstanding debt under our revolving credit facility as of March 31, 2009.

(b) The term loan facility is fully secured by restricted investments.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Credit Agreement

We have an $824.6 million 5-year credit agreement that matures June 21, 2012, or the Credit Agreement, which consists of:

- a $764.6 million revolving credit facility; and
- a $60.0 million term loan facility.

The above amounts are net of non-participation by Lehman Brothers Commercial Bank. At March 31, 2009 and December 31, 2008, we had $0.3 million of letters of credit outstanding under the Credit Agreement. 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 March 31, 2009 the available capacity under the revolving credit facility was $183.0 million.

Other Agreements

As of March 31, 2009, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million, which reduces the amount of cash we may be required to post as collateral. We pay a fee of 0.8% per annum on this letter of credit. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under the Credit Agreement.

8. Risk Management and Hedging Activities

Our day to day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures by using physical and financial derivative instruments. We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The following briefly describes each of the risks that we manage.

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, sales and storage activities. For gathering and processing services, we may receive fees or commodities as payment for these services, depending on the types of contracts. We enter into derivative financial instruments to mitigate the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. Additionally, given the limited depth of the NGL derivatives market, we utilize crude oil derivatives to mitigate a significant portion of our commodity price exposure for propane and heavier NGLs. Historically, there has been a 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 mitigate NGL price risk. As a result of the current movements in the relationship of NGL prices to crude oil prices outside of recent historical ranges, we have additional exposure to changes in the correlation. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2013 with natural gas, crude oil and NGL derivative instruments. These transactions are primarily accomplished through the use of forward contracts, swap futures that effectively exchange our floating rate price risk for a fixed rate, but the type of instrument that we use to mitigate our risk may vary depending upon our risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within our condensed consolidated statements of operations.

Our Wholesale Propane Logistics segment is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. 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. However, to the extent that we carry propane inventories or our sales and supply arrangements are not aligned, we are exposed to market variables and commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. While the majority of our sales and purchases in this segment are index-based, occasionally, we may enter into fixed price sales agreements in

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. In such cases, we may manage this risk with derivatives that allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These transactions are not designated as hedging instruments for accounting purposes and the change in value is reflected within our condensed consolidated statements of operations.

Furthermore, with respect to our Pelico system, we may enter into financial derivatives to lock in price differentials across the system to maximize its value. This objective may be achieved through the use of physical purchases or sales of gas that are accounted for under accrual accounting. While the physical purchase or sale of gas transactions are accounted for under accrual accounting, the swaps are not designated as hedging instruments for accounting purposes and any change in fair value of these instruments is reflected within our condensed consolidated statements of operations.

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for derivatives that manage our commodity price risk. We have used the mark-to-market method of accounting for all derivatives that manage our commodity price risk since July 2007, thus changes in fair value are recorded directly to the condensed consolidated statements of operations. Derivative contracts that were put in place prior to this date may have been designated as cash flow or fair value hedges, and are described below.

Commodity Cash Flow Hedges 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 recorded in accumulated other comprehensive income, or 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.

Given our election to discontinue using the hedge method of accounting, the remaining net loss deferred in AOCI relative to these cash flow hedges will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the underlying transactions impact earnings. Subsequent to July 1, 2007, the changes in fair value of financial derivatives are included in gains and losses from commodity derivative activity in the condensed consolidated statements of operations.

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. As described above relative to our Wholesale Propane Logistics segment, we may have hedged producer price locks, or 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 linked to the New York Mercantile Exchange or an index-based position.

Interest Rate Risk

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 $575.0 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 swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. The effect that these swaps have on our condensed consolidated financial statements, as well as the effect that is expected over the upcoming 12 months is summarized in the charts below. 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. $425.0 million of the agreements reprice prospectively approximately every 90 days and the remaining $150.0 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 2.26% to 5.19%, and receive interest payments based on the three-month and one-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swap Dealers Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- If we were to have an event of default, of any covenant to our credit agreement, that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.

- In the event that DCP Midstream, LLC was to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties may have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.

- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. For example, if we were to fail to make a required interest or principal payment on a debt instrument, above a predefined threshold level, and after giving effect to any applicable notice or grace period as defined in the ISDA, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.

Our commodity derivative contracts that are not governed by ISDA agreements do not have any credit-risk related contingent features.

Depending upon the movement of commodity prices, each of our individual contracts with counterparties to our commodity derivative instruments are in either a net asset or net liability position. As of March 31, 2009, we had approximately $1.5 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have posted $0 in the form of cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA permits us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of March 31, 2009 if a credit-risk related event were to occur, we would not be required to post any additional collateral in the form of cash since our commodity derivative contracts in a net asset position more than offset our contracts in a net liability position. Furthermore, our commodity derivative contracts that contain credit-risk related contingent features have a net asset position that exceeds the value of our contracts in a net liability position by approximately $21.6 million as of March 31, 2009.

As of March 31, 2009 our interest rate swaps were in a net liability position of approximately $39.9 million, of which, the entire amount is subject to credit-risk related contingent features. If we were to have a default of any of our covenants to our credit agreement, that occurs and is continuing, the counterparties to our swap instruments may have the right to request that we net settle the instrument in the form of cash.

Collateral

As of March 31, 2009, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million. This letter of credit reduces the amount of cash we may be required to post as collateral. As of March 31, 2009, we had no cash collateral posted with counterparties to our commodity derivative instruments.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Summarized Derivative Information

The following summarizes the balance within AOCI relative to our commodity and interest rate cash flow hedges:

	March 31, 2009	December 31, 2008
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (1.2)	$ (1.8)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(39.3)	(38.7)
Total AOCI	$ (40.5)	$ (40.5)

The fair value of our derivative instruments that are designated as hedging instruments, those that are marked to market each period, as well as the location of each within our condensed consolidated balance sheets, by major category, is summarized as follows:

Balance Sheet Line Item	March 31, 2009	December 31, 2008	Balance Sheet Line Item	March 31, 2009	December 31, 2008
	(Millions)			(Millions)	
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments:**		
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (17.2)	$ (16.5)
Unrealized gains on derivative instruments long term			Unrealized losses on derivative instruments long term	(22.7)	(22.8)
	$	$		$ (39.9)	$ (39.3)
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments current	$ 15.8	$ 15.4	Unrealized losses on derivative instruments current	$ (1.2)	$ (1.2)
Unrealized gains on derivative instruments long term	9.5	8.6	Unrealized losses on derivative instruments long term	(3.6)	(3.2)
	$ 25.3	$ 24.0		$ (4.8)	$ (4.4)

The following table summarizes the impact on our condensed consolidated balance sheet and condensed consolidated statements of operations of our derivative instruments that are accounted for using the cash flow hedge method of accounting.

	Gain (Loss) Recognized in AOCI on Derivatives Effective Portion		Gain (Loss) Reclassified From AOCI to Earnings Effective Portion			Gain (Loss) Recognized in Income on Derivatives Ineffective Portion and Amount Excluded From Effectiveness Testing			Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	Three Months Ended March 31,								
	2009	2008	2009	2008		2009	2008		
	(Millions)		(Millions)			(Millions)			(Millions)
Interest rate derivatives	$ (4.5)	$ (13.7)	$ (4.0)	$ (0.1)	(b)	$	$	(b)(c)	$ (16.5)
Commodity derivatives	$	$	$ (0.5)	$ (0.3)	(a)	$	$	(a)(c)	$ (0.8)

(a) Included in sales of natural gas, propane, NGLs and condensate in our condensed consolidated statements of operations.

(b) Included in interest expense in our condensed consolidated statements of operations.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

(c) For the three months ended March 31, 2009 and 2008, 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.

Changes in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the condensed consolidated statements of operations. The following summarizes these amounts and the location within the condensed consolidated statements of operations that such amounts are reflected:

Commodity Derivatives	Statements of Operations Line Item	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
		(Millions)	
Third party:			
Realized		$ 6.9	$ (7.0)
Unrealized		0.8	(30.8)
	Gains (losses) from commodity derivative activity, net	$ 7.7	$ (37.8)
Affiliates:			
Realized		$ (0.7)	$ (2.1)
Unrealized			2.8
	(Losses) gains from commodity derivative activity, net affiliates	$ (0.7)	$ 0.7

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

The following table represents, by commodity type, our net long or short positions that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the table below.

	March 31, 2009		
Year of Expiration	Crude Oil Net Long (Short) Position (Bbls)	Natural Gas Net Long (Short) position (MMbtu)	Natural Gas Liquids Net Long (Short) Position (Bbls)
2009	(673,750)	(1,142,500)	17,321
2010	(950,225)	(1,841,000)	1,547
2011	(949,000)	(547,500)	
2012	(850,950)	(549,000)	
2013	(456,250)	(547,500)	

We periodically enter into interest rate swap agreements to mitigate our floating rate interest exposure. As of March 31, 2009 we have swaps with a notional value between $25.0 million and $150.0 million, which, in aggregate, exchange $575.0 million of our floating rate obligation to a fixed rate obligation.

9. 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.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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; and

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

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

General Partner Interest and Incentive Distribution Rights The general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest, approximately 1% as of March 31, 2009. 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 incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. The general partner s incentive distribution rights were not reduced as a result of our common limited partner unit issuances, 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 after the Subordination Period* section below for more details about the distribution targets and their impact on the general partner s incentive distribution rights.

Subordinated Units All of our subordinated units were held by DCP Midstream, LLC. The subordination period had an early termination provision that permitted 50% of the subordinated units, or 3,571,428 units, to convert into common units on a one-to-one basis in February 2008 and permitted the other 50% of the subordinated units, or 3,571,429 units, to convert into common units on a one-to-one basis in February 2009, following the satisfactory completion of the tests for ending the subordination period contained in our partnership agreement. Our board of directors certified that all conditions for early conversion were satisfied.

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, which ended in February 2009, 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 2009 and 2008:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
February 13, 2009	$ 0.600	$ 20.1
November 14, 2008	0.600	20.1
August 14, 2008	0.600	20.1
May 15, 2008	0.590	19.6
February 14, 2008	0.570	15.7

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

10. Net Income or 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, through the date of subordinated conversion, in accordance with their respective ownership percentages, after allocating Available Cash generated during the period in accordance with our partnership agreement.

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 our Available Cash it will have the impact of reducing net income per LPU. During the three months ended March 31, 2009 and 2008, 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 additional earnings allocated to the general 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 March 31, 2009	Three Months Ended March 31, 2008
	(Millions)	
Net income (loss) attributable to partners	$ 22.1	$ (6.5)
General partner interest in net income or net loss	(3.2)	(2.6)
Net income (loss) available to limited partners	$ 18.9	$ (9.1)
Net income (loss) per LPU basic and diluted	$ 0.67	$ (0.36)

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 17 in Item 8 of our 2008 Form 10-K for additional details.

Anderson Gulch In February 2009, the Colorado Department of Public Health and Environment, or CDPHE, issued a Notice of Violation that alleges violations of the environmental permit at our Anderson Gulch gas plant in 2008. The Anderson Gulch gas plant is owned by Collbran Valley Gas Gathering, LLC, our 70% owned joint venture in western Colorado. In March 2009, the CDPHE proposed a penalty of approximately $230,000 to resolve both this matter as well as alleged violations at an unrelated asset owned by DCP Midstream, LLC. We are currently in settlement discussions with the CDPHE to resolve these matters.

El Paso On February 27, 2009, a jury in the District Court, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream, LLC. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream, LLC in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we recorded a contingent liability of $2.5 million for this matter, which is included in other current liabilities in the condensed consolidated balance sheets as of March 31, 2009 and December 31, 2008.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 2008 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; (3) our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery; (4) our Colorado and Wyoming systems; and (5) our Michigan systems (acquired in October 2008).

Wholesale Propane Logistics The Wholesale Propane Logistics segment consists of five owned and operated rail terminals, one leased marine terminal, one pipeline terminal and access to several open-access pipeline terminals.

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.

The following tables set forth our segment information:

Three Months Ended March 31, 2009

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics (Millions)	Other	Total
Total operating revenues	$ 106.0	$ 132.8	$ 1.8	$	$ 240.6
Gross margin (a)	$ 30.7	$ 25.8	$ 1.3	$	$ 57.8
Operating and maintenance expense	(6.2)	(2.7)	(0.3)		(9.2)
Depreciation and amortization expense	(9.7)	(0.3)	(0.4)		(10.4)
General and administrative expense				(5.8)	(5.8)
(Losses) earnings from equity method investments	(2.6)		0.4		(2.2)
Interest income				0.2	0.2
Interest expense				(7.3)	(7.3)
Income tax expense (b)				(0.1)	(0.1)
Net income (loss)	12.2	22.8	1.0	(13.0)	23.0

Net income attributable to noncontrolling interests		(0.9)								(0.9)
Net income (loss) attributable to partners	$	11.3	$	22.8	$	1.0	$	(13.0)	$	22.1
Non-cash derivative mark-to-market (c)	$	0.1	$	0.2	$		$	(0.1)	$	0.2
Capital expenditures	$	25.6	$	0.1	$		$		$	25.7

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Three Months Ended March 31, 2008

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics (Millions)	Other	Total
Total operating revenues	$ 133.4	$ 201.7	$ 2.6	$	$ 337.7
Gross margin (a)	$ (2.5)	$ 8.6	$ 1.9	$	$ 8.0
Operating and maintenance expense	(7.7)	(2.7)	(0.2)		(10.6)
Depreciation and amortization expense	(7.8)	(0.3)	(0.4)		(8.5)
General and administrative expense				(5.5)	(5.5)
Earnings from equity method investments	16.8		0.4		17.2
Interest income				1.6	1.6
Interest expense				(8.1)	(8.1)
Net (loss) income	(1.2)	5.6	1.7	(12.0)	(5.9)
Net income attributable to noncontrolling interests	(0.6)				(0.6)
Net (loss) income attributable to partners	$ (1.8)	$ 5.6	$ 1.7	$ (12.0)	$ (6.5)
Non-cash derivative mark-to-market (c)	$ (31.0)	$ 2.7	$	$ (0.3)	$ (28.6)
Capital expenditures	$ 8.3	$ 0.8	$ 0.1	$	$ 9.2

	March 31, 2009	December 31, 2008
	(Millions)	
Segment long-term assets:		
Natural Gas Services	$ 871.8	$ 856.4
Wholesale Propane Logistics	54.2	54.3
NGL Logistics	33.4	33.8
Other (d)	71.8	70.3
Total long-term assets	1,031.2	1,014.8
Current assets	118.3	165.2
Total assets	$ 1,149.5	$ 1,180.0

(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.

(b) Income tax expense relates primarily to the Michigan business tax.

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

(d) 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.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Supplemental Cash Flow Information

	Three Months Ended March 31, 2009	2008
	(Millions)	
Cash paid for interest, net of amounts capitalized	$ 3.7	$ 8.6
Non-cash investing and financing activities:		
Non-cash additions of property, plant and equipment	$ 1.3	$ 2.1

14. Subsequent Events

On April 28, 2009, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on May 15, 2009 to unitholders of record on May 8, 2009.

On April 1, 2009, we completed our acquisition from DCP Midstream, LLC of an additional 25.1% ownership interest in East Texas in exchange for 3,500,000 Class D Units. The Class D units will automatically convert into common units in August 2009 and will not be eligible to receive a distribution until the second quarter distribution payable in August 2009. DCP Midstream, LLC also provided a fixed price NGL derivative by NGL component for the period of April 2009 to March 2010 for the newly acquired interest. In conjunction with the acquisition of our additional 25.1% interest in East Texas, DCP Midstream, LLC will continue to be responsible for 75% of certain East Texas capital expenditures from April 1, 2009 through completion of the capital projects, for a period not to exceed three years. Subsequent to this transaction we will consolidate our 50.1% interest in East Texas and we will consequently no longer disclose East Texas as an equity method investment. As a result of this transaction, DCP Midstream, LLC owns an approximately 37% limited partnership interest and an approximately 1% general partnership interest in us.

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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 2008 Form 10-K.

Overview

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

- our Natural Gas Services segment, which consists of (1) our Northern Louisiana natural gas gathering, processing and transportation system; (2) our Southern Oklahoma system; (3) our limited liability company interests in DCP East Texas Holdings, LLC, or East Texas, and Discovery Producer Services LLC, or Discovery; (4) our Colorado and Wyoming systems and (5) our Michigan systems (acquired in October 2008);

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

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

Recent Events

On April 28, 2009, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on May 15, 2009 to unitholders of record on May 8, 2009.

On April 1, 2009, we completed our acquisition from DCP Midstream, LLC of an additional 25.1% ownership interest in East Texas in exchange for 3,500,000 Class D Units. The Class D units will automatically convert into common units in August 2009 and will not be eligible to receive a distribution until the second quarter distribution payable in August 2009. DCP Midstream, LLC also provided a fixed price NGL derivative by NGL component for the period of April 2009 to March 2010 for the newly acquired interest. In conjunction with the acquisition of our additional 25.1% interest in East Texas, DCP Midstream, LLC will continue to be responsible for 75% of certain East Texas capital expenditures from April 1, 2009 through completion of the capital projects, for a period not to exceed three years. Subsequent to this transaction we will consolidate our 50.1% interest in East Texas and we will consequently no longer disclose East Texas as an equity method investment. As a result of this transaction, DCP Midstream, LLC owns an approximately 37% limited partnership interest and an approximately 1% general partnership interest in us.

In March 2009, we completed the third and final phase of our pipeline integrity and system enhancement project on the Wyoming natural gas gathering system. The system upgrade project was conducted to assure pipeline integrity, improve system reliability and reduce operating costs.

In March 2009, repairs were completed to Discovery s offshore gathering system and the system was returned to full service. Discovery s offshore gathering system sustained damage during Hurricane Ike in September 2008, when an 18-inch lateral was severed from its connection to the 30 inch mainline in 250 feet of water. The 30-inch mainline was repaired and placed back into service in January 2009. With the recent completion of repairs on the 18-inch lateral, Discovery s offshore gathering system is now fully operational and flowing approximately 400 MMcf/d of natural gas through Discovery s onshore Larose natural gas processing plant.

In March 2009, operations were fully restored at our East Texas natural gas processing complex and residue natural gas delivery system known as the Carthage Hub. In February 2009, production was temporarily shut in following a fire resulting from a third party underground pipeline rupture that occurred just outside DCP Midstream, LLC s property line. We are actively pursuing full reimbursement of our costs and lost margin associated with the incident from the responsible third party.

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Factors That Significantly Affect Our Results

Natural Gas Services Segment

Our results of operations for our Natural Gas Services segment are impacted by (1) increases and decreases in the volume of natural gas that we gather and transport through our systems, which we refer to as throughput, (2) prices of commodities such as NGLs, crude oil and natural gas, (3) the operating efficiency of our processing facilities, and (4) potential limitations on throughput volumes arising from downstream and infrastructure capacity constraints. Throughput and operating efficiency generally are driven by wellhead production, plant recoveries, operating availability of our facilities, physical integrity and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate. Historical and current trends in the price changes of commodities may not be indicative of future trends. Throughput and prices are also driven by demand and take-away capacity for residue natural gas and NGLs.

Natural Gas Services segment results of operations 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, the 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, impacting 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, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. 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.

While pricing impacts the Natural Gas Services segment, we have mitigated a significant portion of the anticipated commodity price risk associated with the equity volumes from our gathering and processing activities, for both our consolidated entities and our proportionate share of exposure from our equity method investments, through 2014 with fixed price natural gas and crude oil swaps. With these swaps, we expect our cash flow exposure to commodity price movements to be reduced. 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. For additional information regarding our derivative activities, please read Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 Form 10-K and Item 3. Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report on Form 10-Q.

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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 domestic production and drilling activity level of exploration and production companies. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity in the future. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall below demand levels.

Wholesale Propane Logistics Segment

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 risk. We may 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. There may be an impact on sales volumes from weather conditions in the Midwest and northeastern areas of the United States. Our annual sales volumes of propane may decline when these areas experience periods of milder weather in the winter months. Volumes may also be impacted by conservation and reduced demand in the current recessionary environment.

NGL Logistics Segment

Our results of operations for our NGL Logistics segment are impacted by the throughput volumes of the NGLs we transport on our NGL pipelines, as we transport NGLs exclusively on a fee basis. Throughput may be negatively impacted as a result of our customers operating their processing plants in ethane rejection mode, often as a result of low commodity prices for ethane. During the fourth quarter of 2008 and into the first quarter of 2009, we did experience reduced throughput due to ethane rejection at certain plants. Factors that impact the supply of and demand for NGLs, as described above in our Natural Gas Services segment, may also impact the throughput for our NGL Logistics segment.

Impact of Severe Weather

The economic impact of severe weather may negatively affect the nation s short-term energy supply and demand, and may result in increased commodity prices. Additionally, severe weather may restrict or prevent us from fully utilizing our assets, by damaging our assets, interrupting utilities, and through possible NGL and natural gas curtailments downstream of our facilities, which restricts our production. These impacts may linger past the time of the actual weather event. Severe weather may also impact the supply and demand in our Wholesale Propane Logistics segment. Although we carry insurance on our assets, insurance may be inadequate to cover our loss and in some instances, we may be unable to obtain insurance on commercially reasonable terms, if at all.

Other

The above factors, including further sustained deterioration in commodity prices, volumes or other market declines, including a decline in our unit price, may negatively impact our results of operations, and may increase the likelihood of a non-cash impairment charge or non-cash lower of cost or market inventory adjustments.

General Trends and Outlook

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

Commodity Prices We are continuing to experience relatively lower commodity prices in 2009. In the fourth quarter of 2008, natural gas, NGL and crude oil prices dropped significantly compared to 2007 and the first three quarters of 2008. Commodity prices are impacted by demand, which has been negatively impacted by the current recessionary environment.

Natural Gas Supply and Outlook In the near term, softening of natural gas prices, reduced demand for natural gas and NGLs, potential reduction in producer s available capital and cash flows, and the recent downturn in the economy is having a moderating effect on levels of drilling activity. The impact of these factors will vary across our broad geographic locations. Generally, we have seen a decrease in drilling levels in the first quarter of 2009. Although we have not seen a significant impact on our throughput volume in the first quarter of 2009 due to reduced drilling levels, throughput volumes could decline in the latter part of 2009 and beyond should natural gas prices and reduced drilling levels remain at current levels. Our long-term view is that as economic conditions improve, natural gas prices will return to a level that would support the relatively higher levels of natural gas-related drilling experienced in recent years in the United States, as producers seek to increase their level of natural gas production.

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 arrangements* Under percent-of-proceeds 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 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 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 natural gas gathered. This arrangement keeps the producer whole to the thermal value of the 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.

The natural gas supply for our gathering pipelines and processing plants is derived primarily from natural gas wells located in Colorado, Louisiana, Michigan, Oklahoma, Texas, Wyoming and the Gulf of Mexico. The Pelico system also receives natural gas produced in Texas through its interconnect with other pipelines that transport natural gas from Texas into western Louisiana. These areas have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. Our two primary suppliers of natural gas in our Natural Gas Services segment represented approximately 34% of the 708 MMcf/d of natural gas supplied to our systems during the three months ended March 31, 2009. 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 directly received by or released from other gathering systems.

We sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. The NGLs extracted from the natural gas at our processing plants are sold at market index prices to DCP Midstream, LLC or its affiliates, or to third parties. In addition, under our merchant

arrangements, we use a subsidiary of DCP Midstream, LLC as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties.

In January 2009, we amended our Pelico gas purchase and sales agreement with DCP Midstream, LLC. As a result of the amendment, our purchases from DCP Midstream, LLC occur upstream of Pelico, rather than at the inlet of Pelico. We assumed from DCP Midstream, LLC a firm transportation agreement with an affiliate to transport our natural gas purchases from DCP Midstream, LLC to Pelico. In addition, historically, the sales price of a portion of the natural gas we sold to DCP Midstream, LLC was determined based on the price at which we purchased the natural gas from DCP Midstream, LLC plus a portion of the index differential between upstream sources to certain downstream indices with a maximum and minimum differential. Accordingly, DCP Midstream, LLC purchases natural gas and we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. For volumes supplied to certain industrial end users and any volumes in excess of the on-system demand, DCP Midstream, LLC will purchase natural gas from us and sell it certain industrial end users, or transport it to sales points at an index-based price less contractually agreed to marketing fees. 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. 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, two of which are affiliated entities, represented approximately 98% of our propane supplied during the three months ended March 31, 2009. 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 allow us to maintain our generally favorable relationships with our customers.

We manage our wholesale propane margins by selling propane to retail propane distributors under annual sales agreements negotiated each spring that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. 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. Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may continue to periodically recognize non-cash lower of cost or market inventory adjustments. 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 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, Segment Gross Margin and Adjusted Segment 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 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.

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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 March 31, 2009	Three Months Ended March 31, 2008
Reconciliation of Non-GAAP Measures	**(Millions)**	
Reconciliation of net income (loss) attributable to partners to gross margin:		
Net income (loss) attributable to partners	$ 22.1	$ (6.5)
Interest expense	7.3	8.1
Income tax expense	0.1	
Operating and maintenance expense	9.2	10.6
Depreciation and amortization expense	10.4	8.5
General and administrative expense	5.8	5.5
Interest income	(0.2)	(1.6)
Losses (earnings) from equity method investments	2.2	(17.2)
Net income attributable to noncontrolling interests	0.9	0.6
Gross margin	$ 57.8	$ 8.0
Non-cash derivative mark-to-market (a)	$ 0.2	$ (28.6)
Reconciliation of segment net income (loss) attributable to partners to segment gross margin:		
Natural Gas Services segment:		
Segment net income (loss) attributable to partners	$ 11.3	$ (1.8)
Operating and maintenance expense	6.2	7.7
Depreciation and amortization expense	9.7	7.8
Losses (earnings) from equity method investments	2.6	(16.8)
Net income attributable to noncontrolling interests	0.9	0.6
Segment gross margin	$ 30.7	$ (2.5)
Non-cash derivative mark-to-market (a)	$ 0.1	$ (31.0)
Wholesale Propane Logistics segment:		
Segment net income attributable to partners	$ 22.8	$ 5.6
Operating and maintenance expense	2.7	2.7
Depreciation and amortization expense	0.3	0.3
Segment gross margin	$ 25.8	$ 8.6
Non-cash derivative mark-to-market (a)	$ 0.2	$ 2.7
NGL Logistics segment:		
Segment net income attributable to partners	$ 1.0	$ 1.7
Operating and maintenance expense	0.3	0.2

Depreciation and amortization expense	0.4	0.4
Earnings from equity method investment	(0.4)	(0.4)
Segment gross margin	$ 1.3	$ 1.9

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

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 $43.0 million, to certain counterparties to our commodity derivative instruments. We anticipate incurring a total of $9.7 million for all fees under the Omnibus Agreement in 2009. During the three months ended March 31, 2009 and 2008, we incurred $2.4 million for both periods, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $0.7 million and $0.5 million, 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 attributable to partners less interest income, plus interest expense, income tax expense and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus non-cash commodity derivative losses, less non-cash commodity derivative gains. EBITDA and adjusted EBITDA are used as supplemental liquidity and performance 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;

- 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.

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.

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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 March 31,	
	2009	**2008**
Reconciliation of Non-GAAP Measures	**(Millions)**	
Reconciliation of net income (loss) attributable to partners to EBITDA:		
Net income (loss) attributable to partners	$ 22.1	$ (6.5)
Interest income	(0.2)	(1.6)
Interest expense	7.3	8.1
Income tax expense	0.1	
Depreciation and amortization expense	10.4	8.5
EBITDA	$ 39.7	$ 8.5
Reconciliation of net cash provided by operating activities to EBITDA:		
Net cash provided by operating activities	$ 26.6	$ 25.1
Interest income	(0.2)	(1.6)
Interest expense	7.3	8.1
Distributions from equity method investments, net of losses and earnings, respectively	(2.7)	(2.0)
Income tax expense	0.1	
Net changes in operating assets and liabilities	9.6	(21.0)
Other, net	(1.0)	(0.1)
EBITDA	$ 39.7	$ 8.5

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, noncontrolling 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 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.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2008 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three months ended March 31, 2009 are the same as those described in our 2008 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 months ended March 31, 2009 and 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended March 31,		Variance 2009 vs. 2008	
	2009 (a)	2008	Increase (Decrease)	Percent
	(Millions, except as indicated)			
Operating revenues:				
Natural Gas Services	$ 106.0	$ 133.4	$ (27.4)	(21)%
Wholesale Propane Logistics	132.8	201.7	(68.9)	(34)%
NGL Logistics	1.8	2.6	(0.8)	(31)%
Total operating revenues	240.6	337.7	(97.1)	(29)%
Gross margin (b):				
Natural Gas Services	30.7	(2.5)	33.2	*
Wholesale Propane Logistics	25.8	8.6	17.2	200%
NGL Logistics	1.3	1.9	(0.6)	(32)%
Total gross margin	57.8	8.0	49.8	623%
Operating and maintenance expense	(9.2)	(10.6)	(1.4)	(13)%
General and administrative expense	(5.8)	(5.5)	0.3	5%
(Losses) earnings from equity method investments (c)	(2.2)	17.2	(19.4)	*
Net income attributable to noncontrolling interests	(0.9)	(0.6)	0.3	50%
EBITDA (d)	39.7	8.5	31.2	367%
Depreciation and amortization expense	(10.4)	(8.5)	1.9	22%
Interest income	0.2	1.6	(1.4)	(88)%
Interest expense	(7.3)	(8.1)	(0.8)	(10)%
Income tax expense	(0.1)		0.1	100%
Net income (loss) attributable to partners	$ 22.1	$ (6.5)	$ 28.6	*
Operating data:				
Natural gas throughput (MMcf/d) (c)	930	829	101	12%
NGL gross production (Bbls/d) (c)	16,374	25,191	(8,817)	(35)%
Propane sales volume (Bbls/d)	37,092	33,914	3,178	9%
NGL pipelines throughput (Bbls/d) (c)	23,969	31,876	(7,907)	(25)%

* Percentage change is not meaningful.

(a) Includes the results of MPP since October 1, 2008, the date of acquisition.

(b) 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.

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

(d) EBITDA consists of net income or loss attributable to partners 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 March 31, 2009 vs. Three Months Ended March 31, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

- $67.9 million decrease primarily attributable to lower propane prices, partially offset by increased sales volumes driven by an increase in spot sales, for our Wholesale Propane Logistics segment;
- $76.2 million decrease primarily attributable to decreased commodity prices and a decrease in NGL and condensate volumes, partially offset by increased natural gas volumes, and a January 1, 2009 amendment to a contract with an affiliate such that our sales to the affiliate are no longer associated with our purchases from the affiliate, which resulted in a prospective change in certain Pelico revenues from a net presentation to a gross presentation, for our Natural Gas Services segment; and
- $0.6 million decrease due to decreased throughput volumes resulting from ethane rejection at certain connected processing plants in our NGL Logistics segment; partially offset by
- $43.8 million increase related to commodity derivative activity, resulting from the following:
  - we had a gain of $7.0 million in 2009 and a loss of $37.1 million in 2008, resulting in an increase of $44.1 million, which is included in gains (losses) from commodity derivative activity. This increase includes an increase in unrealized gains of $28.8 million due to forward prices of commodities generally being lower in 2009 compared to 2008 and a decrease in realized cash settlement losses of $15.3 million due to average prices of commodities generally being lower in 2009 compared to 2008; and
  - we had a $0.3 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate; and
- $3.8 million increase in transportation processing and other revenue, primarily attributable to the MPP acquisition in our Natural Gas Services segment.

Gross Margin Gross margin increased in 2009 compared to 2008, primarily due to the following:

- $33.2 million increase for our Natural Gas Services segment primarily due to increases related to commodity derivative activity and the MPP acquisition, partially offset by the impact of decreased commodity prices and lower natural gas, NGL and condensate production; and
- $17.2 million increase for our Wholesale Propane Logistics segment as a result of increased per unit margins, approximately $6.0 million of which was attributable to the sale of inventory that was written down at the end of the fourth quarter of 2008, as well as increased volumes; partially offset by
- $0.6 million decrease for our NGL Logistics segment, primarily attributable to decreased throughput volumes resulting from ethane rejection at certain connected processing plants.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2009 compared to 2008, primarily as a result of our cost reduction initiatives, partially offset by increased expenses as a result of the MPP acquisition in our Natural Gas Services segment.

General and Administrative Expense General and administrative expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition.

Earnings from Equity Method Investments Earnings from equity method investments decreased in 2009 compared to 2008, primarily due to the impact of hurricanes on Discovery and the impact from the third party pipeline rupture and fire on East Texas, as discussed in the Natural Gas Services Segment section below. Settlements related to our commodity derivatives on our equity method investments are included in segment gross margin.

Noncontrolling Interest in Income Noncontrolling interest in income reduced income by $0.9 million and $0.6 million in 2009 and 2008, respectively, and represents the noncontrolling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, and in 2009 the noncontrolling interest holders portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition during 2008.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition.

Results of Operations Natural Gas Services Segment

This segment consists of our Northern Louisiana system, the Southern Oklahoma system, a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, our Colorado and Wyoming systems, and our Michigan systems acquired in October 2008.

	Three Months Ended March 31,		Variance 2009 vs. 2008	
	2009 (a)	2008	Increase (Decrease)	Percent
	(Millions, except as indicated)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 84.3	$ 160.8	$ (76.5)	(48)%
Transportation, processing and other	14.7	10.7	4.0	37%
Gains (losses) from commodity derivative activity	7.0	(38.1)	45.1	*
Total operating revenues	106.0	133.4	(27.4)	(21)%
Purchases of natural gas and NGLs	75.3	135.9	(60.6)	(45)%
Segment gross margin (b)	30.7	(2.5)	33.2	*
Operating and maintenance expense	(6.2)	(7.7)	(1.5)	(19)%
Depreciation and amortization expense	(9.7)	(7.8)	1.9	24%
(Losses) earnings from equity method investments (c)	(2.6)	16.8	(19.4)	*
Segment net income (loss)	12.2	(1.2)	13.4	*
Segment net income attributable to noncontrolling interests	(0.9)	(0.6)	0.3	50%
Segment net income (loss) attributable to partners	$ 11.3	$ (1.8)	$ 13.1	*
Operating data:				
Natural gas throughput (MMcf/d) (c)	930	829	101	12%
NGL gross production (Bbls/d) (c)	16,374	25,191	(8,817)	(35)%

* Percentage change is not meaningful.

(a) Includes the results of MPP since October 1, 2008, the date of acquisition.

(b) 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.

(c)

Includes our proportionate share of the throughput volumes and earnings of East Texas and Discovery for each period presented. Earnings for Discovery include the amortization of the net difference between the carrying amount of the investment and the underlying equity of the investment.

Three Months Ended March 31, 2009 vs. Three Months Ended March 31, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

- $80.0 million decrease attributable to decreased commodity prices; partially offset by

- $44.8 million increase related to commodity derivative activity, resulting from the following:

  - a gain of $7.0 million in 2009 and a loss of $38.1 million in 2008, resulting in an increase of $45.1 million, which is included in gains (losses) from commodity derivative activity. This increase includes an increase in unrealized gains of $31.3 million due to forward prices of commodities generally being lower in 2009 compared to 2008, and an increase in realized cash settlement gains of $13.8 million due to average prices of commodities generally being lower in 2009 compared to 2008; offset by a $0.3 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate;

$3.8 million increase attributable to increased natural gas volumes, and a January 1, 2009 amendment to a contract with an affiliate such that our sales to the affiliate are no longer associated with our purchases from the affiliate, which resulted in a prospective change in certain Pelico revenues from a net presentation to a gross presentation, partially offset by a decrease in NGL and condensate volumes; and

$4.0 million increase in transportation, processing and other revenue, primarily as a result of the MPP acquisition.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased in 2009 compared to 2008, primarily due to lower costs of natural gas supply, driven by lower commodity prices, partially offset by an amendment to a contract with an affiliate, which resulted in a prospective change in certain Pelico purchases from a net presentation to a gross presentation.

Segment Gross Margin Segment gross margin increased in 2009 compared to 2008, primarily as a result of the following:

$44.8 million increase related to commodity derivative activity, as discussed in the Operating Revenues section above; and

$4.9 million increase primarily as a result of the MPP acquisition; partially offset by

$12.6 million decrease due to lower commodity prices; and

$3.9 million decrease due to lower natural gas, NGL and condensate production.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2009 compared to 2008, primarily as a result of our cost reduction initiatives, partially offset by increased expenses as a result of the MPP acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition.

Earnings from Equity Method Investments Earnings from equity method investments decreased in 2009 compared to 2008, primarily due to the impact of hurricanes on Discovery and the impact from the third party pipeline rupture and fire on East Texas. Settlements related to our commodity derivatives on our equity method investments are included in segment gross margin. Decreased equity earnings were primarily as a result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

Decreased equity earnings from Discovery were the result of a decrease in Discovery s net income of $28.1 million due primarily to $23.0 million lower NGL sales margins resulting from lower volumes and lower average per-unit margins on NGL processing agreements, a $4.5 million unfavorable other income, net and $2.6 million lower fee based revenue, partially offset by $3.1 million lower depreciation and accretion expense.

Decreased equity earnings from East Texas were the result of a decrease in East Texas s net income of $30.6 million due primarily to a $14.0 million decrease as a result of lower commodity prices, a $13.2 million decrease due to decreased volumes, primarily due to production temporarily being shut in following a fire resulting from a third party underground pipeline rupture, and a $3.3 million decrease in fee-based revenue.

Noncontrolling Interest in Income Noncontrolling interest in income reduced income by $0.9 million and $0.6 million in 2009 and 2008, respectively, and represents the noncontrolling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture and in 2009 the noncontrolling interest holders portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition.

Natural gas transported, processed and/or treated increased in 2009 compared to 2008, due primarily to increased volumes from the MPP acquisition, partially offset by decreased volumes from Discovery and East Texas. NGL production decreased in 2009 compared to 2008, due primarily to decreased NGL production at Discovery as a result of hurricane damage, and decreased production at East Texas due to production being temporarily shut in following a fire resulting from a third party underground pipeline rupture.

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Results of Operations Wholesale Propane Logistics Segment

This segment includes our propane transportation facilities, which includes five owned and operated rail terminals, one leased marine terminal, one pipeline terminal, and access to several open-access pipeline terminals:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Variance 2009 vs. 2008 Increase (Decrease)	Variance 2009 vs. 2008 Percent
	(Millions, except as indicated)			
Operating revenues:				
Sales of propane	$ 132.8	$ 200.7	$ (67.9)	(34) %
Gains from commodity derivative activity		1.0	(1.0)	*
Total operating revenues	132.8	201.7	(68.9)	(34) %
Purchases of propane	107.0	193.1	(86.1)	(45) %
Segment gross margin (a)	25.8	8.6	17.2	200 %
Operating and maintenance expense	(2.7)	(2.7)		%
Depreciation and amortization expense	(0.3)	(0.3)		
Segment net income attributable to partners	$ 22.8	$ 5.6	$ 17.2	307 %
Operating data:				
Propane sales volume (Bbls/d)	37,092	33,914	3,178	9%

* 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 March 31, 2009 vs. Three Months Ended March 31, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

- $87.7 million decrease attributable to lower propane prices;
- $1.0 million decrease related to commodity derivative activity, which represents a decrease in unrealized gains of $2.5 million recognized in 2008, partially offset by decreased realized cash settlement losses of $1.5 million recognized in 2008; partially offset by
- $19.8 million increase attributable to increased propane sales volumes, driven by an increase in spot sales.

Purchases of Propane Purchases of propane decreased in 2009 compared to 2008, primarily due to decreased per unit prices, partially offset by increased purchase volumes.

Segment Gross Margin Segment gross margin increased in 2009 compared to 2008, primarily as a result of increased per unit margins, approximately $6.0 million of which was attributable to the sale of inventory that was written down at the end of the fourth quarter of 2008, as well as increased volumes, partially offset by decreases related to commodity derivative activity.

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Results of Operations NGL Logistics Segment

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Variance 2009 vs. 2008 Increase (Decrease)	Variance 2009 vs. 2008 Percent
	(Millions, except as indicated)			
Operating revenues:				
Sales of NGLs	$ 0.6	$ 1.2	$ (0.6)	(50)%
Transportation, processing and other	1.2	1.4	(0.2)	(14)%
Total operating revenues	1.8	2.6	(0.8)	(31)%
Purchases of NGLs	0.5	0.7	(0.2)	(29)%
Segment gross margin (a)	1.3	1.9	(0.6)	(32)%
Operating and maintenance expense	(0.3)	(0.2)	0.1	50%
Depreciation and amortization expense	(0.4)	(0.4)		%
Earnings from equity method investment (b)	0.4	0.4		%
Segment net income attributable to partners	$ 1.0	$ 1.7	$ (0.7)	(41)%
Operating data:				
NGL pipelines throughput (Bbls/d) (b)	23,969	31,876	(7,907)	(25)%

* Percentage change is not meaningful.

(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 each period presented.

Three Months Ended March 31, 2009 vs. Three Months Ended March 31, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to decreased throughput volumes resulting from ethane rejection at certain connected processing plants.

Purchases of NGLs Purchases of NGLs decreased in 2009 compared to 2008, due primarily to decreased throughput volumes resulting from ethane rejection at certain connected processing plants.

Segment Gross Margin Segment gross margin decreased in 2009 compared to 2008, primarily due to decreased throughput volumes resulting from ethane rejection at certain connected processing plants.

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Liquidity and Capital Resources

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 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;
- quarterly distributions to our unitholders;
- contributions to our equity method investments to finance our share of their capital expenditures;
- business and asset acquisitions; and
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts, which may, at times, be significant depending on commodity price movements, and which is required to the extent we exceed certain guarantees issued by DCP Midstream, LLC and letters of credit we have posted.

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. In the event these sources are not sufficient, we would reduce our discretionary spending.

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, as well as impact our compliance with our financial covenant requirements under our credit agreement.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a significant portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through 2014 with fixed price natural gas and crude oil swaps. For additional information regarding our derivative activities, please read Item7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 Form 10-K and Item 3. Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report on Form 10-Q.

Our banking group is comprised of various financial institutions, of which certain institutions have recently merged. We do not expect the aggregate contractual financial commitment of these institutions to us to change during the remaining life of our existing credit agreement as a result of these mergers.

We have a 5-year credit agreement, or the Credit Agreement, consisting of a $764.6 million revolving credit facility and a $60.0 million term loan facility at March 31, 2009. These amounts are net of non-participation by Lehman Brothers Commercial Bank. Our borrowing capacity may be limited by the Credit Agreement s financial covenant requirements. Except in the case of a default, which would make the borrowings under the Credit Agreement fully callable, amounts borrowed under the Credit Agreement will not mature prior to the June 21, 2012 maturity date. As of May 4, 2009, we had approximately $214.0 million of net available borrowings under the Credit Agreement.

The counterparties to each of our commodity 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. As of May 4, 2009 DCP Midstream, LLC had issued and outstanding parental guarantees totaling $83.0 million to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with these counterparties. We pay DCP Midstream LLC a fee of 0.5% per annum on $40.0 million of these parental guarantees. The fee on the remaining parental guarantees of $43.0 million, which were provided prior to our initial public offering, is covered under the omnibus agreement with DCP Midstream, LLC. As of May 4, 2009 we had a letter of credit of $10.0 million, on which we pay a fee of 0.8% per annum. These parental guarantees and letter of credit reduce the amount of cash we may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under our credit facility. As of May 4, 2009, 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 commodity derivative instruments 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.

If we were to have an event of default, of any covenant to our credit agreement, that occurs and is continuing, our International Swap Dealers Association, or ISDA, counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions. In the event that DCP Midstream, LLC was to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties may have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position. Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. For example, if we were to fail to make a required interest or principal payment on a debt instrument, above a predefined threshold level, and after giving effect to any applicable notice or grace period as defined in the ISDA, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.

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

As of March 31, 2009, we had $12.0 million in cash and cash equivalents. Of this balance, as of March 31, 2009, $0.2 million was held by Collbran Valley Gas Gathering, or Collbran, our 70% owned joint venture which we consolidate in our financial results. Other than the cash held by Collbran, this cash balance was available for general corporate purposes.

We had working capital of $12.5 million and $40.4 million as of March 31, 2009 and December 31, 2008, 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.

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Cash Flow Operating, investing and financing activities were as follows:

	Three Months Ended March 31,	
	2009	2008
	(Millions)	
Net cash provided by operating activities	$ 26.6	$ 25.1
Net cash used in investing activities	$ (28.0)	$ (141.6)
Net cash (used in) provided by financing activities	$ (34.6)	$ 145.1

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 three months ended March 31, 2009 and 2008 totaling $6.2 million and $9.1 million, respectively.

We received cash distributions from equity method investments of $0.5 million and $19.2 million during the three months ended March 31, 2009 and 2008, respectively. Distributions exceeded losses by $2.7 million for the three months ended March 31, 2009 and exceeded earnings by $2.0 million for the three months ended March 31, 2008.

Net Cash Used in Investing Activities Net cash used in investing activities during the three months ended March 31, 2009 was comprised of: (1) capital expenditures of $25.7 million, which primarily consisted of expenditures for expansion of our Collbran system and completion of the pipeline integrity system upgrades to our Douglas system; (2) investments in equity investments of $1.8 million; (3) a payment of $0.3 million related to our acquisition of MPP; and (4) net purchases of available-for-sale securities of $0.2 million.

Net cash used in investing activities during the three months ended March 31, 2008, was primarily used for: (1) capital expenditures of $9.2 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) a payment of $10.9 million related to our acquisition of the MEG subsidiaries; (3) investments in Discovery of $1.9 million and East Texas of $0.9 million; and (4) net purchases of available-for-sale securities of $118.7 million.

We invested cash in equity method investments of $1.8 million and $2.8 million during the three months ended March 31, 2009 and 2008, respectively, of which $1.8 million and $1.9 million, respectively, was to fund our share of capital expansion projects, and $0.9 million in 2008 was to fund working capital needs.

Net Cash (Used in) Provided by Financing Activities Net cash used in financing activities during the three months ended March 31, 2009 was comprised of (1) distributions to our unitholders of $20.1 million; (2) payments of debt of $11.5 million; and (3) net distributions to noncontrolling interests of $3.0 million.

Net cash provided by financing activities during the three months ended March 31, 2008 was comprised (1) of borrowings of $255.0 million; (2) net proceeds from sales of common limited partner units of $132.3 million; (3) contributions from noncontrolling interests of $2.1 million; and (4) contributions from DCP Midstream, LLC of $1.9 million, partially offset by; (5) distributions to our unitholders and general partner of $16.2 million; and (5) repayments of debt of $230.0 million.

During the three months ended March 31, 2009, total outstanding indebtedness under our $824.6 million credit agreement, which includes borrowings under our revolving credit facility, our term loan facility and letters of credit issued under the credit agreement, was not less than $645.3 million and did not exceed $656.8 million. The weighted average indebtedness outstanding for the three months ended March 31, 2009 and 2008 was $656.7 million and $643.1 million, respectively.

During the three months ended March 31, 2009 we had no incremental borrowings under our credit facility and we repaid $11.5 million on our revolving credit facility.

During the three months ended March 31, 2008, we borrowed (1) $75.0 million under our revolving credit facility for general corporate purposes; (2) $30.0 million under our revolving credit facility to fund a partial retirement of our term loan facility; and (3) $150.0 million under our term loan facility; and we repaid $200.0 million on our revolving credit facility and $30.0 million on our term loan facility.

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We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 9 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 (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets) in each case if such addition, improvement, acquisition or construction is made to increase our operating capacity or revenues.

We incur capital expenditures for our consolidated entities and our equity method investments. Our capital expenditures totaled $25.7 million and $9.2 million, including maintenance capital expenditures of $7.2 million and $0.8 million, and expansion capital expenditures of $18.5 million and $8.4 million, during the three months ended March 31, 2009 and 2008, respectively. These amounts do not reflect capital expenditures for our equity method investments, as those expenditures are recognized as capital contributions to those entities. Maintenance capital expenditures for the first quarter of 2009 included $6.8 million to complete the pipeline integrity and system upgrades to our Douglas system.

We anticipate maintenance capital expenditures of approximately $3.0 million to $8.0 million and expansion capital expenditures of approximately $50.0 million for the remainder of 2009. The board of directors may approve additional growth capital during the year, at their discretion.

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. We may invest a total of up to approximately $105.0 million in this project to achieve ultimate throughput capacity of over 600 MMcf/d. We have invested approximately $5.6 million in 2008 and $11.4 million during the first quarter of 2009 on this project.

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 net investment is approximately $14.0 million, which represents 25% of the total cost of the project. Of this total, we spent approximately $1.3 million in 2008 and $4.3 million during the three months ended March 31, 2009. We expect to spend the remaining $8.4 million in 2009. The pipeline began service in May 2009.

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

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. If these sources are not sufficient, we may reduce our capital spending.

Given our long-term strategy of profitable growth, our long-term objective is to obtain an investment grade credit rating, to increase our available sources to fund capital expenditures.

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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 and general partner of $20.1 million during the three months ended March 31, 2009, as compared to $16.2 million for the same period in 2008. We intend to make quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

Description of the Credit Agreement We have a 5-year credit agreement, or the Credit Agreement, consisting of a $764.6 million revolving credit facility and a $60.0 million term loan facility at March 31, 2009. The Credit Agreement matures on June 21, 2012. As of March 31, 2009, the outstanding balance on the revolving credit facility was $585.0 million and the outstanding balance on the term loan facility was $60.0 million.

Our obligations under the revolving credit facility are unsecured, and the term loan facility is secured at all times by high-grade securities, which are classified as restricted investments in the accompanying condensed consolidated balance sheets, in an amount equal to or greater than the outstanding principal amount of the term loan. 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 or construction of assets in the midstream energy business. The unused portion of the revolving credit facility may be used for letters of credit. At March 31, 2009 and December 31, 2008, we had outstanding letters of credit issued under the Credit Agreement of $0.3 million.

As of March 31, 2009, the weighted-average interest rate on our revolving credit facility was 1.57% per annum.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of March 31, 2009, is as follows:

		Payments Due by Period			
	Total	Remainder of 2009	2010-2011	2012-2013	2014 and Thereafter
			(Millions)		
Long-term debt (a)	$ 730.2	$ 20.3	$ 52.1	$ 657.8	$
Operating lease obligations	44.0	8.7	19.9	12.8	2.6
Purchase obligations (b)	569.6	96.2	194.7	180.0	98.7
Other long-term liabilities (c)	8.4		0.8	0.1	7.5
Total	$ 1,352.2	$ 125.2	$ 267.5	$ 850.7	$ 108.8

(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 $20.2 million of purchase orders for capital expenditures and $549.4 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 March 31, 2009. 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 $7.4 million of asset retirement obligations and $1.0 million of environmental reserves recognized in the March 31, 2009 condensed consolidated balance sheet.

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

Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or 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. We adopted the provisions of SFAS 161 effective January 1, 2009, and have included all required disclosures in this filing. SFAS 161 impacts only disclosures so there was no effect on our consolidated results of operations, cash flows or financial position as a result of adoption.

***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. We adopted SFAS 160 effective January 1, 2009, which required retrospective restatement of our condensed consolidated financial statements for all periods presented in this filing. As a result of adoption, we have reclassified our noncontrolling interest on our condensed consolidated balance sheets, from a component of liabilities to a component of equity and have also reclassified net income attributable to noncontrolling interest on our condensed consolidated statements of operations, to below net income for all periods presented. Furthermore, we have displayed the portion of other comprehensive income that is attributable to the noncontrolling interest within our condensed consolidated statements of comprehensive income. We also added a rollforward of the noncontrolling interest within our condensed consolidated statements of changes in equity.

***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 subsequent to January 1, 2009 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. We adopted SFAS 141(R) effective January 1, 2009, and will account for all transactions with closing dates subsequent to adoption in accordance with the provisions of this standard.

***SFAS No. 157 Fair Value Measurements*, or SFAS 157** In September 2006, the FASB issued SFAS 157, which we adopted on January 1, 2008. Pursuant to FASB Staff Position, or FSP, 157-2, the FASB issued a partial deferral, ending on December 31, 2008, of the implementation of SFAS 157 as it relates to all nonfinancial assets and liabilities where fair value is the required measurement attribute by other accounting standards. Effective January 1, 2009, we adopted SFAS 157 for all nonfinancial assets and liabilities. There was no effect on our consolidated results of operations, cash flows, or financial position, and we have included all required disclosures as a result of the adoption of this standard relative to nonfinancial assets and liabilities. The provisions of SFAS 157 will be applied at such time a fair value measurement of a nonfinancial asset or nonfinancial liability is required, which may result in a fair value that is different than would have been calculated prior to the adoption of SFAS 157.

***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 an intangible asset. We adopted FSP 142-3 on January 1, 2009. As a result of acquisitions, we have intangible assets for customer contracts and related relationships in our condensed consolidated balance sheets. Generally, costs to renew or extend such contracts are not significant, and are expensed to the condensed consolidated statements of operations as incurred. During the current quarter, there were no contracts that were recognized as intangible assets that were renewed or extended.

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***FSP No. SFAS 157-4 Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* or FSP 157-4** In April 2009, the FASB issued FSP 157-4, which provides additional guidance on the valuation of assets or liabilities that are held in markets that have seen a significant decline in activity. While this FSP does not change the overall objective of determining fair value, it emphasizes that in markets with significantly decreased activity and the appearance of non-orderly transactions, an entity may employ multiple valuation techniques, to which significant adjustments may be required, to determine the most appropriate fair value. Generally, for instruments that we measure at fair value, we do not transact within markets that have seen either a significant change in the volume of activity, or in the relevance of the related pricing, which would affect the validity and reliability of our fair value measurements. This FSP becomes effective for us for annual and interim periods beginning after June 30, 2009. We are currently in the process of assessing the impact of this FSP on our operations, but we do not expect there to be a significant effect on our consolidated results of operations, cash flows or financial position as a result of adoption.

***FSP No. SFAS 141(R)-1 Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies,* or FSP 141(R)-1** In April 2009, the FASB issued FSP 141(R)-1, which provides additional guidance on the valuation of assets and liabilities assumed in a business combination that arise from contingencies, which would otherwise be subject to the provisions of SFAS No. 5 Accounting for Contingencies, or SFAS 5. This FSP emphasizes the guidance set forth in SFAS 141(R) that assets and liabilities assumed in a business combination that have an estimated fair value should be recorded at the time of acquisition. Assets and liabilities where the fair value may not be determinable during the measurement period will continue to be recognized pursuant to SFAS 5. This FSP becomes effective for us for business combinations with closing dates subsequent to January 1, 2009. During the first quarter of 2009 we did not have any transactions that were accounted for as business combinations. We will account for any business combinations with closing dates subsequent to the effective date in accordance with this new guidance.

FSP No. SFAS 107-1 and APB 28-1 Interim Disclosures about Fair Value of Financial Instruments This FSP was issued in April 2009, and requires disclosure of summarized financial information for financial instruments accounted for under SFAS No. 107 Disclosures about Fair Value of Financial Instruments, or SFAS 107. We have instruments that are subject to the fair value disclosure requirements of SFAS 107, and will be subject to the revised disclosure provisions of this FSP. This FSP becomes effective for us for annual and interim periods beginning after June 30, 2009, and we will begin providing this information in our interim and annual statements subsequent to the effective date of this FSP.

FSP No. SFAS 115-2 and SFAS 124-2 Recognition and Presentation of Other-Than-Temporary Impairments This FSP was issued in April 2009, and amends the other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This FSP becomes effective for us for annual and interim periods beginning after June 30, 2009, and we will begin providing this information in our interim and annual statements subsequent to the effective date of this FSP. We are currently in the process of evaluating the impact of this FSP on our operations, but do not believe that it will have a significant impact on our consolidated results of operations, cash flows or financial position.

***Emerging Issues Task Force, or EITF, 08-6 Equity Method Investment Accounting Considerations*, or EITF 08-6** In November 2008 the EITF issued EITF 08-6. Although the issuance of SFAS 141(R) and SFAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee s issuance of shares should be accounted for; and d) how to account for a change in an investment from the equity method to the cost method. This issue became effective for us on January 1, 2009, and although it has not impacted the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

***EITF 07-4 Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships* or EITF 07-4** In March 2008, the EITF issued EITF 07-4. This issue seeks to improve the comparability of earnings per unit, or EPU, calculations for master limited partnerships with incentive distribution rights in accordance with FASB Statement No. 128 and its related interpretations. We adopted EITF 07-4 effective January 1, 2009. As a result of adopting EITF 07-4, undistributed earnings or losses are reduced or increased, respectively, by the amount of available cash that was generated during the current period, and undistributed earnings are no longer allocated to our general partner with respect to its incentive distribution rights, as our partnership agreement specifically limits incentive distributions to available cash. EITF 07-4 is applied retrospectively for all periods. We have retrospectively restated our previously disclosed net income (loss) per limited partner unit, or LPU, and related disclosures, within this filing. As a result of adoption, net loss per LPU increased from $(0.33) per unit to $(0.36) per unit for the three months ended March 31, 2008.

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Item 3. ***Quantitative and Qualitative Disclosures about Market Risk***

For an in-depth discussion of our market risks, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 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 $575.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. 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 March 31, 2009, the effective weighted-average interest rate on our $585.0 million of outstanding revolver debt was 4.59%, taking into account the $575.0 million of indebtedness with designated interest rate swaps.

Based on the annualized unhedged borrowings under our credit facility of $70.0 million as of March 31, 2009, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.4 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, sales and storage activities. For gathering services, we receive fees or commodities from producers to bring the natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, depending on the 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 fixed price natural gas and crude oil contracts to mitigate the effect pricing fluctuations may have on the value of our assets and operations. Depending on our risk management objectives, we may periodically settle a portion of these instruments prior to their maturity.

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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 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 mitigate NGL price risk. As a result of these transactions, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk through 2014.

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.

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.

The following table sets forth our commodity derivative instruments as of May 4, 2009:

Period	Commodity	Notional Volume	Reference Price	Swap Price Range
April 2009 December 2009	Natural Gas	2,000 MMBtu/d	Texas Gas Transmission Price (a)	$9.20/MMBtu
April 2009 December 2009	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
April 2009 December 2010	Natural Gas	1,634 MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (e)	$3.94/MMBtu
January 2010 December 2010	Natural Gas	1,900 MMBtu/d	Texas Gas Transmission Price (a)	$9.20/MMBtu
January 2010 December 2010	Natural Gas	1,000 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
January 2011 December 2011	Natural Gas	1,000 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
January 2012 December 2012	Natural Gas	1,000 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
January 2013 December 2013	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
April 2009 December 2009	Natural Gas Basis	1,500 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (c)	NYMEX less $0.68/MMBtu
January 2010 December 2010	Natural Gas Basis	1,000 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (c)	NYMEX less $0.68/MMBtu
January 2011 December 2011	Natural Gas Basis	1,000 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (c)	NYMEX less $0.68/MMBtu
January 2012 December 2012	Natural Gas Basis	1,000 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (c)	NYMEX less $0.68/MMBtu
January 2013 December 2013	Natural Gas Basis	1,500 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (c)	NYMEX less $0.68/MMBtu
April 2009 December 2009	Crude Oil	2,450 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$63.05 - $86.95/Bbl
January 2010 December 2010	Crude Oil	2,415 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$63.05 - $87.25/Bbl
April 2010 December 2011	Crude Oil	250 Bbls/d	Asian-pricing of NYMBEX crude oil futures (d)	$56.75 - $59.30/Bbl
January 2011 December 2011	Crude Oil	2,350 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$66.72 - $87.25/Bbl
January 2012 December 2012	Crude Oil	2,125 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$66.72 - $90.00/Bbl
January 2013 December 2013	Crude Oil	1,750 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$67.60 - $74.40/Bbl
January 2014 December 2014	Crude Oil	700 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$74.90 - $76.25/Bbl
April 2009 March 2010	NGLs	839 Bbls/d	Mt. Belvieu Non-TET (f)	$0.66 - $1.63/Gal

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

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

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

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

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

(f) The average monthly OPIS price for Mt. Belvieu Non-TET.

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We utilize crude oil derivatives to mitigate a significant portion of our commodity price exposure for propane and heavier NGLs. Due to current movements in the relationship of NGL prices to crude oil prices outside of recent historical ranges, we have provided an additional sensitivity factor to capture movements up or down in this relationship. We have combined the NGL and crude oil sensitivities into one factor, and added our sensitivity to changes in the relationship between the pricing of NGLs and crude oil. For fixed price natural gas and crude oil, the sensitivities are associated with our unhedged volumes. For our NGL to crude oil price relationship, the sensitivity is associated with both hedged and unhedged equity volumes. Given our current contract mix and the commodity derivative contracts we have in place, we have updated our annualized sensitivities for 2009 as shown in the table below, which excludes the impact from mark-to-market on our commodity derivatives. The following sensitivities reflect the acquisition of an additional interest of 25.1% in DCP East Texas Holdings, LLC on April 1, 2009.

Commodity Sensitivities Excluding Non-Cash Mark-To-Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 0.1
Crude oil prices (a)	$ 5.00	Barrel	$ 1.4
NGL to crude oil price relationship (b)	5 percentage point change	Barrel	$ 4.3

(a) Assuming 60% NGL to crude oil price relationship.

(b) Assuming 60% NGL to crude oil price relationship and $60.00/Bbl crude oil price. Generally, this sensitivity changes by $1.5 million for each $20.00/Bbl change in the price of crude oil. As crude oil prices increase from $60.00/Bbl, we become slightly more sensitive to the change in the relationship of NGL prices to crude oil prices. As crude oil prices decrease from $60.00/Bbl, we become less sensitive to the change in the relationship of NGL prices to crude oil prices.

In addition to the linear relationships in our commodity sensitivities above, additional factors cause us to be less sensitive to commodity price declines. A portion of our net income is derived from fee-based contracts and a certain percentage of liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as NGL prices decline.

The above sensitivities exclude the impact from arrangements where producers on a monthly basis may elect to not process their natural gas in which case we retain a portion of the customers natural gas in lieu of NGLs as a fee. The above sensitivities also exclude certain related processing arrangements where we control the processing or by-pass of the production based upon individual economic processing conditions. Under each of these types of arrangements, our processing of the natural gas would yield favorable processing margins. Less than 10% of our gas throughput is associated with these arrangements.

We estimate the following non-cash sensitivities in 2009 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in

					Net Income) (Millions)
Natural gas prices	$	1.00	MMBtu	$	3.9
Crude oil prices	$	5.00	Barrel	$	20.7
NGL prices	$	0.10	Gallon	$	1.2

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, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. 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. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing activities through 2014. Given the historical correlation between NGL prices and crude oil prices and lack of liquidity in the NGL financial market, we have generally used crude oil swaps to mitigate NGL price risk. As a result of the current movements in the relationship of NGL prices to crude oil prices outside of recent historical ranges, we have additional exposure to changes in the 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 domestic production and drilling activity level of exploration and production companies. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity in the future. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed, but would likely increase commodity prices.

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 three months ended March 31, 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

Except for the matter noted below, the information required for this item is provided in Note 17, Commitments and Contingent Liabilities, included in Item 8 of our 2008 Form 10-K, which information is incorporated by reference into this item.

Anderson Gulch In February 2009, the Colorado Department of Public Health and Environment, or CDPHE, issued a Notice of Violation that alleges violations of the environmental permit at our Anderson Gulch gas plant in 2008. The Anderson Gulch gas plant is owned by Collbran Valley Gas Gathering, LLC, our 70% owned joint venture in western Colorado. In March 2009, the CDPHE proposed a penalty of approximately $230,000 to resolve both this matter as well as alleged violations at an unrelated asset owned by DCP Midstream, LLC, the owner of our general partner. We are currently in settlement discussions with the CDPHE to resolve these matters. Management currently believes that the ultimate resolution of this matter, after consideration of amounts accrued or other indemnification arrangements, will not have a material adverse effect on our consolidated results of operations, financial position, or cash flows.

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 2008 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 2008 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 2008 Form 10-K:

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

Our gathering and transportation pipeline systems are connected to or dependent on the level of production from natural gas wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and NGL pipelines and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and NGLs, and to attract new customers to our assets, include the level of successful drilling activity near these assets, the demand for natural gas and crude oil, producers desire and ability to obtain necessary permits in an efficient manner, natural gas field characteristics and production performance, surface access and infrastructure issues, and our ability to compete for volumes from successful new wells. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells or because of competition, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows.

Recent commodity price erosion, the credit market crisis and the current economic conditions may adversely affect natural gas and NGL producers drilling activity and transportation spending levels, which may in turn negatively impact our volumes and results of operations and our ability to make distributions to our unitholders.

The level of drilling activity is dependent on economic and business factors beyond our control. Among the factors that impact drilling decisions are natural gas prices and the deterioration generally of the credit and financial markets. Natural gas prices are lower in recent periods when compared to historical periods. For example, the rolling twelve-month average New York Mercantile Exchange, or NYMEX, daily settlement price of natural gas futures contracts per MMBtu was $4.83 as of March 31, 2009 and was $6.21, $7.96 and $7.23 as of December 31, 2008, 2007 and 2006, respectively. During periods of natural gas price decline, in particular in periods when capital markets are experiencing severe strain as in the current economy, the level of drilling activity could decrease. Suppliers which finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity may not be able or willing to do so under current market conditions, which continue to demonstrate a decline from prior periods in credit availability and a reduction in equity values. When combined with a reduction of cash flow resulting from recent declines in natural gas prices, a reduction in our producers borrowing base under reserve-based credit facilities and lack of availability of debt or equity financing for our producers may result in a significant reduction in our producers spending for natural gas drilling activity, which could result in lower volumes being transported on our pipeline systems.

Furthermore, a sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering and pipeline transportation systems and our natural gas treating and processing plants, which could lead to reduced utilization of these assets. For example, exploration and production companies have announced that the depressed natural gas prices may lead to reduced capital expenditures in 2009, which could lead them to shut-in wells and reduce production. Other factors that impact production decisions include the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of natural gas to replace the declines due to reductions in drilling activity, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows, and ability to make cash distributions.

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

Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our credit facility contains covenants requiring us to maintain certain leverage and other financial ratios and tests. Any subsequent replacement of our credit facility or any new indebtedness could have similar or greater restrictions. If our covenants are not met, whether as a result of reduced production levels of natural gas and NGLs as described above or otherwise, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

Our assets and operations can be affected by weather and other weather related conditions.

Our assets and operations can be adversely affected by hurricanes, floods, tornadoes, wind, lightening and other natural phenomena, which could impact our results of operations and make it more difficult for us to realize historic rates of return. Although we carry insurance on our assets, insurance may be inadequate to cover our loss and in some instances, we may be unable to obtain insurance on commercially reasonable terms, if at all. If we incur a significant disruption in our operations or a significant liability for which we were not fully insured, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

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Item 6. ***Exhibits***
Exhibits

Exhibit Number		Description
10.1	*	Contribution Agreement dated February 25, 2009, among DCP Midstream Partners, LP, DCP LP Holdings, LLC, DCP Midstream GP, LP and DCP Midstream, LLC (attached as Exhibit 10.16 to DCP Midstream Partners LP s Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
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.

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on May 11, 2009.

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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EXHIBIT INDEX

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