UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 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 **(State or other jurisdiction of incorporation or organization)**	**03-0567133** **(I.R.S. Employer Identification No.)**
370 17th Street, Suite 2775 Denver, Colorado **(Address of principal executive offices)**	**80202** **(Zip Code)**

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

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

Indicate by check mark whether the registrant 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	☒
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 ☒

As of August 3, 2009, there were outstanding 28,233,183 common limited partner units and 3,500,000 Class D units.

DCP MIDSTREAM PARTNERS, LP
FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2009

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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

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, inflation rates, 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 the operation of company owned and third-party-owned infrastructure;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment, including climate change legislation, 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)

	June 30, 2009	December 31, 2008
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4.6	$ 61.9
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.8 million and $1.0 million, respectively	35.2	58.8
Affiliates	57.6	57.5
Inventories	16.9	20.9
Unrealized gains on derivative instruments	5.9	15.4
Other	1.7	0.9
Total current assets	121.9	215.4
Restricted investments	35.1	60.2
Property, plant and equipment, net	973.9	882.7
Goodwill	89.1	88.8
Intangible assets, net	46.0	47.7
Equity method investments	117.0	111.5
Unrealized gains on derivative instruments	3.8	8.6
Other long-term assets	4.6	4.8
Total assets	$1,391.4	$ 1,419.7
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 57.3	$ 71.6
Affiliates	13.4	36.0
Unrealized losses on derivative instruments	25.7	17.7
Accrued interest payable	0.8	1.3
Other	33.3	36.6
Total current liabilities	130.5	163.2
Long-term debt	638.0	656.5
Unrealized losses on derivative instruments	43.6	26.0
Other long-term liabilities	13.8	11.2
Total liabilities	825.9	856.9
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	66.0
Common unitholders (28,233,183 and 24,661,754 units issued and outstanding, respectively)	320.5	429.0
Class D unitholders (3,500,000 and 0 units issued and outstanding, respectively)	67.7	—
Subordinated unitholders (0 and 3,571,429 convertible units issued and outstanding, respectively)	—	(54.6)
General partner interest	(5.6)	(4.8)
Accumulated other comprehensive loss	(31.0)	(40.5)
Total partners' equity	351.6	395.1
Noncontrolling interests	213.9	167.7
Total equity	565.5	562.8
Total liabilities and equity	$1,391.4	$ 1,419.7

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 71.8	$ 236.2	$229.0	$ 532.3
Sales of natural gas, propane, NGLs and condensate to affiliates	101.9	274.6	201.8	475.7
Transportation, processing and other	20.7	9.5	37.4	22.4
Transportation, processing and other to affiliates	3.5	11.3	7.1	17.6
Losses from commodity derivative activity, net	(44.0)	(184.9)	(36.3)	(222.7)
Losses from commodity derivative activity, net — affiliates	(1.9)	(2.4)	(2.6)	(1.7)
Total operating revenues	152.0	344.3	436.4	823.6
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	110.6	397.5	248.4	746.8
Purchases of natural gas, propane and NGLs from affiliates	37.7	48.9	116.8	130.8
Operating and maintenance expense	17.1	19.3	33.3	37.3
Depreciation and amortization expense	16.3	13.0	30.9	25.7
General and administrative expense	2.0	3.0	5.2	5.5
General and administrative expense — affiliates	5.1	4.8	10.5	9.9
Other, net	—	(1.5)	—	(1.5)
Total operating costs and expenses	188.8	485.0	445.1	954.5
Operating loss	(36.8)	(140.7)	(8.7)	(130.9)
Interest income	0.1	2.0	0.3	3.7
Interest expense	(7.0)	(7.9)	(14.3)	(16.0)
Earnings from equity method investments	3.7	7.1	2.6	17.8
Loss before income taxes	(40.0)	(139.5)	(20.1)	(125.4)
Income tax expense	—	(0.3)	(0.1)	(0.6)
Net loss	(40.0)	(139.8)	(20.2)	(126.0)
Net (income) loss attributable to noncontrolling interests	(2.1)	(13.3)	(0.8)	(27.0)
Net loss attributable to partners	(42.1)	(153.1)	(21.0)	(153.0)
Net (income) loss attributable to predecessor operations	—	(6.2)	1.0	(12.8)
General partner interest in net income or net loss	(2.7)	(0.7)	(5.9)	(3.4)
Net loss allocable to limited partners	$ (44.8)	$ (160.0)	$ (25.9)	$(169.2)
Net loss per limited partner unit — basic and diluted	$ (1.41)	$ (5.67)	$ (0.86)	$ (6.36)
Weighted-average limited partner units outstanding — basic and diluted	31.7	28.2	30.0	26.6

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Millions)			
Net loss	$ (40.0)	$ (139.8)	$ (20.2)	$ (126.0)
Other comprehensive income:				
Reclassification of cash flow hedges into earnings	4.7	2.3	9.2	2.7
Net unrealized gains (losses) on cash flow hedges	4.8	12.6	0.3	(1.1)
Total other comprehensive income	9.5	14.9	9.5	1.6
Total comprehensive loss	(30.5)	(124.9)	(10.7)	(124.4)
Total comprehensive income attributable to noncontrolling interests	(2.1)	(13.3)	(0.8)	(27.0)
Total comprehensive loss attributable to partners	$ (32.6)	$ (138.2)	$ (11.5)	$ (151.4)

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Millions)	
OPERATING ACTIVITIES:		
Net loss	$ (20.2)	$(126.0)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization expense	30.9	25.7
Earnings from equity method investments, net of distributions	0.4	4.0
Other, net	(0.2)	(1.0)
Change in operating assets and liabilities, which provided (used) cash: net of effects of acquisition:		
Accounts receivable	22.8	(23.0)
Inventories	4.0	(2.0)
Net unrealized losses on derivative instruments	54.0	198.9
Accounts payable	(38.0)	16.7
Accrued interest	(0.5)	(0.8)
Other current assets and liabilities	(2.3)	(21.4)
Other long-term assets and liabilities	0.4	(0.3)
Net cash provided by operating activities	51.3	70.8
INVESTING ACTIVITIES:		
Capital expenditures	(118.4)	(31.2)
Acquisition of Michigan Pipeline & Processing, LLC	(0.1)	—
Acquisition of subsidiaries of Momentum Energy Group, Inc	—	(10.9)
Investments in equity method investments	(5.8)	(1.9)
Proceeds from sale of assets	0.3	—
Purchases of available-for-sale securities	(1.1)	(461.9)
Proceeds from sales of available-for-sale securities	26.1	341.9
Net cash used in investing activities	(99.0)	(164.0)
FINANCING ACTIVITIES:		
Proceeds from debt	68.3	432.0
Payments of debt	(86.8)	(402.0)
Proceeds from issuance of common units, net of offering costs	—	132.1
Net change in advances to predecessor from DCP Midstream, LLC	3.0	(12.6)
Distributions to unitholders and general partner	(40.2)	(35.8)
Distributions to noncontrolling interests	(4.9)	(34.6)
Contributions from noncontrolling interests	50.3	9.3
Contributions from DCP Midstream, LLC	0.7	1.9
Net cash (used in) provided by financing activities	(9.6)	90.3
Net change in cash and cash equivalents	(57.3)	(2.9)
Cash and cash equivalents, beginning of period	61.9	29.3
Cash and cash equivalents, end of period	$ 4.6	$ 26.4

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited)

	Partners' Equity							
	Predecessor Equity	Common Unitholders	Class D Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
				(Millions)				
Balance, January 1, 2009	$ 66.0	$ 429.0	$ —	$ (54.6)	$ (4.8)	$ (40.5)	$ 167.7	$ 562.8
Net change in parent advances	3.0	—	—	—	—	—	—	3.0
Conversion of subordinated units to common units	—	(52.1)	—	52.1	—	—	—	—
Distributions to unitholders and general partner	—	(31.7)	—	(2.1)	(6.4)	—	—	(40.2)
Distributions to noncontrolling interests	—	—	—	—	—	—	(4.9)	(4.9)
Contributions from DCP Midstream, LLC	—	0.7	—	—	—	—	—	0.7
Contributions from noncontrolling interests	—	—	—	—	—	—	50.3	50.3
Other	—	(0.1)	—	—	—	—	—	(0.1)
Issuance of 3,500,000 Class D units	—	—	49.7	—	—	—	—	49.7
Acquisition of additional 25.1% interest in East Texas and the NGL Hedge	(68.0)	—	4.6	—	—	—	—	(63.4)
Deficit purchase price over acquired assets	—	—	18.3	—	—	—	—	18.3
Comprehensive income:								
Net loss attributable to predecessor operations	(1.0)	—	—	—	—	—	—	(1.0)
Net (loss) income	—	(25.3)	(4.9)	4.6	5.6	—	0.8	(19.2)
Reclassification of cash flow hedges into earnings	—	—	—	—	—	9.2	—	9.2
Net unrealized gains on cash flow hedges	—	—	—	—	—	0.3	—	0.3
Total comprehensive (loss) income	(1.0)	(25.3)	(4.9)	4.6	5.6	9.5	0.8	(10.7)
Balance, June 30, 2009	$ —	$ 320.5	$ 67.7	$ —	$ (5.6)	$ (31.0)	$ 213.9	$ 565.5
Balance, January 1, 2008	$ 64.0	$ 308.8	$ —	$ (120.1)	$ (5.4)	$ (14.9)	$ 155.1	$ 387.5
Net change in parent advances	(12.6)	—	—	—	—	—	—	(12.6)
Conversion of subordinated units to common units	—	(66.4)	—	66.4	—	—	—	—
Distributions to unitholders and general partner	—	(24.2)	—	(6.2)	(4.9)	—	—	(35.3)
Distributions to noncontrolling interests	—	—	—	—	—	—	(34.6)	(34.6)
Contributions from DCP Midstream, LLC	—	1.8	—	—	—	—	—	1.8
Contributions from noncontrolling interests	—	—	—	—	—	—	9.3	9.3
Equity-based compensation	—	0.1	—	—	—	—	—	0.1
Issuance of 4,250,000 common units	—	132.1	—	—	—	—	—	132.1
Comprehensive income:								
Net income attributable to predecessor operations	12.8	—	—	—	—	—	—	12.8
Net (loss) income	—	(142.0)	—	(26.0)	2.2	—	27.0	(138.8)
Reclassification of cash flow hedges into earnings	—	—	—	—	—	2.7	—	2.7
Net unrealized losses on cash flow hedges	—	—	—	—	—	(1.1)	—	(1.1)
Total comprehensive (loss) income	12.8	(142.0)	—	(26.0)	2.2	1.6	27.0	(124.4)
Balance, June 30, 2008	$ 64.2	$ 210.2	$ —	$ (85.9)	$ (8.1)	$ (13.3)	$ 156.8	$ 323.9

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(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 interest in Discovery Producer Services LLC, or Discovery; our Wyoming system and a 70% interest in our Colorado system; our 50.1% interest in our East Texas 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 38% of our partnership.

In April 2009, we acquired an additional 25.1% interest in DCP East Texas Holdings, LLC, or East Texas, and a fixed price natural gas liquids derivative by NGL component for the period of April 2009 to March 2010, or NGL Hedge, from DCP Midstream, LLC, in a transaction among entities under common control. Our East Texas system includes a natural gas processing complex with a total capacity of 780 MMcf/d and an NGL fractionator, which serves as the processing facility for our 900-mile gathering system, as well as third party gathering systems. The complex is adjacent to our Carthage Hub, which delivers gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 billion cubic feet per day, acts as a key exchange point for the purchase and sale of residue gas. Transfers of net assets or exchanges of units between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method. Accordingly, these condensed consolidated financial statements include the historical results of East Texas for all periods presented. The NGL Hedge was entered into on the date of the transaction. Accordingly these condensed consolidated financial statements include the results of the NGL Hedge prospectively from April 1, 2009. Prior to this transaction we owned a 25.0% limited liability company interest in East Texas, which we accounted for under the equity method of accounting. Subsequent to this transaction we own a 50.1% interest in East Texas, and account for East Texas as a consolidated subsidiary. The $18.3 million deficit purchase price under the historical basis of the net acquired assets was recorded as an increase in partners' equity, and the $49.7 million of Class D units issued as consideration for this transaction was recorded as an increase in partners' equity. The Class D units will convert into the Partnership's Common units on a one for one basis on August 17, 2009.

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. We refer to the assets, liabilities and operations of East Texas prior to our acquisition of an additional 25.1% from DCP Midstream, LLC in April 2009, collectively as our "predecessor." The condensed consolidated financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity.

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.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

2. Summary of Significant Accounting Policies

Noncontrolling Interest — Noncontrolling interest represents (1) the noncontrolling interest holders' ownership interest in the net assets of Collbran Valley Gas Gathering, a joint venture acquired in August 2007; (2) the noncontrolling interest holders' ownership interest in the net assets of Jackson Pipeline Company, a partnership we acquired in October 2008; and (3) DCP Midstream, LLC's ownership interest in the net assets of East Texas. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party or affiliate interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third party and affiliate investors.

3. Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or SFAS, No. 168 "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a Replacement of FASB Statement No. 162,"* or SFAS 168** — In June 2009, the FASB issued SFAS 168, which establishes the FASB Accounting Standards Codification, or the Codification, as the source of authoritative U.S. Generally Accepted Accounting Principles, or GAAP. The Codification supersedes all existing non-SEC accounting and reporting standards. This SFAS becomes effective for us for annual and interim periods beginning after September 15, 2009 and will not affect our condensed consolidated results of operations, cash flows and financial position as a result of adoption.

***SFAS No. 167 "Amendments to FASB Interpretation No. 46(R),"* or SFAS 167** — In June 2009, the FASB issued SFAS 167, which requires entities to perform additional analysis of their variable interest entities and consolidation methods. This SFAS becomes effective for us on January 1, 2010 and we are in the process of assessing the impact of this guidance on our condensed consolidated results of operations, cash flows and financial position.

***SFAS No. 165 "Subsequent Events,"* or SFAS 165** — In May 2009, the FASB issued SFAS 165, which sets forth the recognition and disclosure requirements for events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. We adopted SFAS 165 effective June 30, 2009, and there was no effect on our condensed consolidated results of operations, cash flows or financial position as a result of adoption. All appropriate disclosure of subsequent events is made within the footnotes.

***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 condensed 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 partners' equity and will present this financial statement on a quarterly basis.

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***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 for all financial assets and liabilities. 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 condensed 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. Certain of the markets in which we transact have seen a decrease in overall volume; however, we believe that these markets continue to provide sufficient liquidity such that transactions are executed in an orderly manner at fair value. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated results of operations, cash flows or financial position.

***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 two quarters 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 are subject to the revised disclosure provisions of this FSP. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated results of operations, cash flows or financial position.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed 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 $(5.66) per unit to $(5.67) per unit and from $(6.33) per unit to $(6.36) per unit for the three and six months ended June 30, 2008, respectively.

4. Acquisitions

Gathering Compression and Processing Assets

On April 1, 2009, we acquired an additional 25.1% interest in East Texas and the NGL Hedge from DCP Midstream, LLC, for aggregate consideration of 3,500,000 Class D units valued at $49.7 million.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Combined Financial Information

The following table presents the impact on the condensed consolidated balance sheet as of December 31, 2008, adjusted for the acquisition of an additional 25.1% interest in East Texas, from DCP Midstream, LLC.

	DCP Midstream Partners, LP (a)	Consolidate East Texas (b)	Remove East Texas Equity Investment (c)	Combined DCP Midstream Partners, LP
		(Millions)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 48.0	$ 13.9	$ —	$ 61.9
Accounts receivable	80.4	35.9	—	116.3
Inventories	20.9	—	—	20.9
Other	15.9	0.4	—	16.3
Total current assets	165.2	50.2	—	215.4
Restricted investments	60.2	—	—	60.2
Property, plant and equipment, net	629.3	253.4	—	882.7
Goodwill and intangible assets, net	136.5	—	—	136.5
Equity method investments	175.4	—	(63.9)	111.5
Other non-current assets	13.4	—	—	13.4
Total assets	$ 1,180.0	$ 303.6	$ (63.9)	$ 1,419.7
LIABILITIES AND EQUITY				
Accounts payable and other current liabilities	$ 124.8	$ 38.4	$ —	$ 163.2
Long-term debt	656.5	—	—	656.5
Other long-term liabilities	34.9	2.3	—	37.2
Total liabilities	816.2	40.7	—	856.9
Commitments and contingent liabilities				
Equity:				
Partners' equity				
Net equity	369.6	129.9	(63.9)	435.6
Accumulated other comprehensive income	(40.5)	—	—	(40.5)
Total partners' equity	329.1	129.9	(63.9)	395.1
Noncontrolling interests	34.7	133.0	—	167.7
Total equity	363.8	262.9	(63.9)	562.8
Total liabilities and equity	$ 1,180.0	$ 303.6	$ (63.9)	$ 1,419.7

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

The following tables present the impact on the condensed consolidated statements of operations, adjusted for the acquisition of an additional 25.1% interest in East Texas, from DCP Midstream, LLC, for the three and six months ended June 30, 2008.

Three Months Ended June 30, 2008

	DCP Midstream Partners, LP (a)	Consolidate East Texas (b)	Remove East Texas Equity Earnings (c)	Combined DCP Midstream Partners, LP
	(Millions)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 318.5	$ 192.3	$ —	$ 510.8
Transportation, processing and other	14.0	6.8	—	20.8
Losses from commodity derivative activity, net	(186.6)	(0.7)	—	(187.3)
Total operating revenues	145.9	198.4	—	344.3
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	287.8	158.6	—	446.4
Operating and maintenance expense	11.0	8.3	—	19.3
Depreciation and amortization expense	9.0	4.0	—	13.0
General and administrative expense and other	3.8	2.5	—	6.3
Total operating costs and expenses	311.6	173.4	—	485.0
Operating (loss) income	(165.7)	25.0	—	(140.7)
Interest expense, net	(6.1)	0.2	—	(5.9)
Earnings from equity method investments	13.4	—	(6.3)	7.1
(Loss) income before income taxes	(158.4)	25.2	(6.3)	(139.5)
Income tax expense	—	(0.3)	—	(0.3)
Net (loss) income	(158.4)	24.9	(6.3)	(139.8)
Net income attributable to noncontrolling interests	(0.9)	(12.4)	—	(13.3)
Net (loss) income attributable to partners	$ (159.3)	$ 12.5	$ (6.3)	$ (153.1)

Six Months Ended June 30, 2008

	DCP Midstream Partners, LP (a)	Consolidate East Texas (b)	Remove East Texas Equity Earnings (c)	Combined DCP Midstream Partners, LP
	(Millions)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 681.2	$ 326.8	$ —	$ 1,008.0
Transportation, processing and other	26.1	13.9	—	40.0
Losses from commodity derivative activity, net	(223.7)	(0.7)	—	(224.4)
Total operating revenues	483.6	340.0	—	823.6
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	617.5	260.1	—	877.6
Operating and maintenance expense	21.6	15.7	—	37.3
Depreciation and amortization expense	17.5	8.2	—	25.7
General and administrative expense and other	9.3	4.6	—	13.9
Total operating costs and expenses	665.9	288.6	—	954.5
Operating (loss) income	(182.3)	51.4	—	(130.9)
Interest expense, net	(12.6)	0.3	—	(12.3)
Earnings from equity method investments	30.6	—	(12.8)	17.8
(Loss) income before income taxes	(164.3)	51.7	(12.8)	(125.4)
Income tax expense	—	(0.6)	—	(0.6)
Net (loss) income	(164.3)	51.1	(12.8)	(126.0)
Net income attributable to noncontrolling interests	(1.5)	(25.5)	—	(27.0)
Net (loss) income attributable to partners	$ (165.8)	$ 25.6	$ (12.8)	$ (153.0)

(a) Amounts as previously reported with 25% of East Texas' results presented as earnings from equity method investments.
(b) Adjustments to present East Texas on a consolidated basis at 100%, with noncontrolling interest of 49.9%.
(c) Adjustments to remove East Texas equity earnings at 25%.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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 June 30, 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 June 30, 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.

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 $7.0 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	2.1
Other assets	0.1
Other long term assets	3.9
Property, plant and equipment	116.1
Goodwill	7.0
Intangible assets	19.6
Other liabilities	(0.5)
Noncontrolling interest in joint venture	(1.6)
Total purchase price allocation	$ 148.4

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Predecessor

DCP Midstream, LLC provided centralized corporate functions on behalf of our predecessor operations, including legal, accounting, cash management, insurance administration and claims processing, risk management, health safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering.

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 June 30, 2009, to certain counterparties to our commodity derivative instruments.

During the three months ended June 30, 2009 and 2008, we incurred $2.4 million and $2.5 million, respectively for all fees under the Omnibus Agreement and incurred other fees with DCP Midstream, LLC of $2.7 million and $2.3 million, respectively. During the six months ended June 30, 2009 and 2008, we incurred $4.8 million and $4.9 million, respectively, for all fees under the Omnibus Agreement and incurred other fees with DCP Midstream, LLC of $5.6 million and $5.0 million, respectively.

Other Agreements and Transactions with DCP Midstream, LLC

In conjunction with our acquisition of an additional 25.1% limited liability company interest in East Texas from DCP Midstream, LLC in April 2009, we entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for certain East Texas capital projects as defined in the Contribution Agreement from April 1, 2009 for a period not to exceed three years. DCP Midstream, LLC made additional capital contributions of $11.5 million during the three months ended June 30, 2009 to East Texas for these capital projects.

On February 11, 2009, we announced that our East Texas natural gas processing complex and natural gas delivery system known as the Carthage Hub, had been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. We are actively pursuing full reimbursement of our costs and lost margin associated with the incident from the responsible third party. We also have insurance covering these amounts, net of applicable deductibles. Following this incident, DCP Midstream, LLC has agreed to reimburse us 25% of any claims received as reimbursement of costs and lost margin, from the responsible third party. DCP Midstream, LLC will pay 75% of costs related to the incident.

On February 25, 2009, we entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC contributed an additional 25.1% interest in East Texas and the NGL Hedge 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 consolidate our 50.1% interest in East Texas and consequently no longer account for 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.
- 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 and six months ended June 30, 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. DCP Midstream, LLC made capital contributions to us during the six months ended June 30, 2009 and 2008 of $0.7 million and $1.6 million, respectively, to reimburse us for these capital projects.

In conjunction with our acquisition of East Texas and Discovery in July 2007 we entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for 25% of certain East Texas capital expenditures, defined in the agreement, from July 1, 2007, through completion of the capital projects for a period not to exceed three years. DCP Midstream, LLC made additional capital contributions to East Texas for these capital projects of $6.2 million and $1.5 million during the six months ended June 30, 2009 and 2008, respectively.

DCP Midstream, LLC has issued additional parental guarantees outside of the Omnibus Agreement, totaling $40.0 million at June 30, 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 $0.7 million and $1.3 million of capital reimbursements during the six months ended June 30, 2009 and 2008, respectively.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Summary of Transactions with Affiliates

The following table summarizes the transactions with affiliates:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$ 101.3	$ 257.3	$ 201.1	$ 455.6
Transportation, processing and other	$ 1.4	$ 6.2	$ 2.6	$ 11.7
Purchases of natural gas, propane and NGLs	$ 19.3	$ 28.1	$ 62.4	$ 103.4
(Losses) gains from commodity derivative activity, net	$ (1.9)	$ (2.4)	$ (2.6)	$ (1.7)
General and administrative expense	$ 5.1	$ 4.8	$ 10.4	$ 9.9
Interest expense	$ —	$ —	$ 0.1	$ —
Spectra Energy:				
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ —	$ 0.2
Transportation, processing and other	$ 0.2	$ 0.1	$ 0.2	$ 0.1
Purchases of natural gas, propane and NGLs	$ 14.5	$ 4.4	$ 48.1	$ 4.4
ConocoPhillips:				
Sales of natural gas, propane, NGLs and condensate	$ 0.6	$ 17.3	$ 0.7	$ 19.9
Transportation, processing and other	$ 1.9	$ 5.0	$ 4.3	$ 5.8
Purchases of natural gas, propane and NGLs	$ 3.9	$ 16.4	$ 5.9	$ 23.0
General and administrative expense	$ —	$ —	$ 0.1	$ —
Unconsolidated affiliates:				
Purchases of natural gas, propane and NGLs	$ —	$ —	$ 0.4	$ —

We had balances with affiliates as follows:

	June 30, 2009	December 31, 2008
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 55.0	$ 51.0
Accounts payable	$ 11.6	$ 30.3
Unrealized gains on derivative instruments—current	$ 1.0	$ —
Unrealized losses on derivative instruments—current	$ (1.0)	$ (1.2)
Spectra Energy:		
Accounts receivable	$ 1.2	$ 4.0
Accounts payable	$ 1.3	$ 5.3
ConocoPhillips:		
Accounts receivable	$ 1.4	$ 2.5
Accounts payable	$ 0.5	$ 0.4

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	Depreciable Life	June 30, 2009	December 31, 2008
		(Millions)	
Gathering systems	15 — 30 Years	$ 576.5	$ 497.7
Processing plants	25 — 30 Years	407.6	383.2
Terminals	25 — 30 Years	28.9	28.5
Transportation	25 — 30 Years	217.5	216.6
Underground storage	20 — 50 Years	0.1	0.1
General plant	3 — 5 Years	15.0	13.9
Construction work in progress		89.1	73.9
Property, plant and equipment		1,334.7	1,213.9
Accumulated depreciation		(360.8)	(331.2)
Property, plant and equipment, net		$ 973.9	$ 882.7

The above amounts include accrued capital expenditures of $18.7 million and $17.4 million as of June 30, 2009 and December 31, 2008, respectively, which are included in other current liabilities in the condensed consolidated balance sheets.

7. Equity Method Investments

The following table summarizes our equity method investments:

	Percentage of Ownership as of June 30, 2009 and December 31, 2008	Carrying Value as of	
		June 30, 2009	December 31, 2008
		(Millions)	
Discovery Producer Services LLC	40%	$110.3	$ 105.0
Black Lake Pipe Line Company	45%	6.5	6.3
Other	50%	0.2	0.2
Total equity method investments		$117.0	$ 111.5

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $38.5 million and $39.7 million at June 30, 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 $5.9 million and $6.0 million at June 30, 2009 and December 31, 2008, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

In the second quarter of 2009, Discovery's LLC agreement was amended to calculate available cash based on cash on hand at the end of the month preceding the end of each calendar quarter (e.g. May 31 for the second quarter) and to require distribution of available cash by the end of each calendar quarter. Prior to this amendment, Discovery calculated available cash based on cash on hand at the end of each calendar quarter and made the related distribution within 30 days of the end of each calendar quarter.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Earnings and distributions from equity method investments were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Millions)			
Discovery Producer Services LLC	$ 3.3	$ 6.9	$ 1.8	$ 17.2
Black Lake Pipe Line Company and other	0.4	0.2	0.8	0.6
Total earnings from equity method investments	$ 3.7	$ 7.1	$ 2.6	$ 17.8
Distributions from equity method investments	$ 2.5	$ 10.4	$ 3.0	$ 21.8
Distributions from equity method investments, net of earnings	$ (1.2)	$ 3.3	$ 0.4	$ 4.0

The following summarizes financial information of our equity method investments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Millions)			
Statements of operations:				
Operating revenue	$ 40.4	$ 84.4	$ 61.9	$ 173.3
Operating expenses	$ 32.9	$ 70.1	$ 58.8	$ 139.5
Net income	$ 7.5	$ 14.5	$ 2.9	$ 37.9

	June 30, 2009	December 31, 2008
	(Millions)	
Balance sheets:		
Current assets	$ 66.5	$ 54.1
Long-term assets	389.5	392.9
Current liabilities	(40.1)	(46.0)
Long-term liabilities	(22.1)	(20.1)
Net assets	$393.8	$ 380.9

8. 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.

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- 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.

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.

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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 relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

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

Interest Rate Derivative Assets and Liabilities

We have interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt. 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 and entity valuation adjustments 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 June 30, 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.

The following table presents the financial instruments carried at fair value as of June 30, 2009 and December 31, 2008:

	June 30, 2009				December 31, 2008			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Commodity derivatives (a)	$ —	$ 4.7	$ 1.2	$ 5.9	$ —	$ 15.1	$ 0.3	$ 15.4
Long-term assets:								
Restricted investments	$ —	$ 35.1	$ —	$ 35.1	$ —	$ 60.2	$ —	$ 60.2
Commodity derivatives (b)	$ —	$ 2.9	$ —	$ 2.9	$ —	$ 6.9	$ 1.7	$ 8.6
Interest rate derivatives (b)	$ —	$ 0.9	$ —	$ 0.9	$ —	$ —	$ —	$ —
Current liabilities (c):								
Commodity derivatives	$ —	$ (6.9)	$ (0.1)	$ (7.0)	$ —	$ (1.2)	$ —	$ (1.2)
Interest rate derivatives	$ —	$(18.7)	$ —	$ (18.7)	$ —	$(16.5)	$ —	$ (16.5)
Long-term liabilities (d):								
Commodity derivatives	$ —	$(29.9)	$ (0.9)	$ (30.8)	$ —	$ (3.2)	$ —	$ (3.2)
Interest rate derivatives	$ —	$(12.8)	$ —	$ (12.8)	$ —	$(22.8)	$ —	$ (22.8)

(a) Included in current unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(b) Included in long-term unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(c) Included in current unrealized losses on derivative instruments in our condensed consolidated balance sheets.
(d) Included in long-term unrealized losses on derivative instruments in our condensed consolidated balance sheets.

Changes in Level 3 Fair Value Measurements

The 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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	Beginning Balance	Net Realized and Unrealized Gains (Losses) Included in Earnings	Transfers In/Out of Level 3 (a)	Purchases, Issuances and Settlements, Net	Ending Balance	Net Unrealized Gains (Losses) Still Held Included in Earnings (b)
			(millions)			
Three months ended June 30, 2009:						
Commodity derivative instruments:						
Current assets	$ 1.0	$ (3.3)	$ —	$ 3.5	$ 1.2	$ (2.6)
Long-term assets	$ 1.7	$ (1.7)	$ —	$ —	$ —	$ (1.7)
Current liabilities	$ —	$ (0.1)	$ —	$ —	$ (0.1)	$ (0.1)
Long-term liabilities	$ (0.3)	$ (0.6)	$ —	$ —	$ (0.9)	$ (0.6)
Three months ended June 30, 2008:						
Commodity derivative instruments:						
Current assets	$ —	$ —	$ 1.0	$ —	$ 1.0	$ —
Long-term assets	$ 1.2	$ (1.1)	$ 1.5	$ —	$ 1.6	$ (1.1)
Current liabilities	$ (1.3)	$ (1.9)	$ (5.3)	$ 1.0	$ (7.5)	$ (1.6)
Long-term liabilities	$ —	$ (3.1)	$ (4.6)	$ —	$ (7.7)	$ (3.1)
Six months ended June 30, 2009:						
Commodity derivative instruments:						
Current assets	$ 0.3	$ (2.7)	$ —	$ 3.6	$ 1.2	$ (2.0)
Long-term assets	$ 1.7	$ (1.7)	$ —	$ —	$ —	$ (1.7)
Current liabilities	$ —	$ (0.1)	$ —	$ —	$ (0.1)	$ (0.1)
Long-term liabilities	$ —	$ (0.9)	$ —	$ —	$ (0.9)	$ (0.9)
Six months ended June 30, 2008:						
Commodity derivative instruments:						
Current assets	$ 0.2	$ 1.0	$ —	$ (0.2)	$ 1.0	$ 0.8
Long-term assets	$ 1.5	$ 0.1	$ —	$ —	$ 1.6	$ 0.1
Current liabilities	$ (1.6)	$ (2.7)	$ (5.0)	$ 1.8	$ (7.5)	$ (2.4)
Long-term liabilities	$ (0.2)	$ (2.9)	$ (4.6)	$ —	$ (7.7)	$ (2.9)

(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 June 30, 2009 and 2008.

9. Debt

Long-term debt was as follows:

	June 30, 2009	December 31, 2008
	(Millions)	
Revolving credit facility, weighted-average interest rate of 1.03% and 2.08%, respectively, due June 21, 2012 (a)	$603.0	$ 596.5
Term loan facility, interest rate of 0.42% and 1.54%, respectively, due June 21, 2012 (b)	35.0	60.0
Total long-term debt	$638.0	$ 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 4.47% on the $603.0 million of outstanding debt under our revolving credit facility as of June 30, 2009.

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

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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 $789.6 million revolving credit facility; and
- a $35.0 million term loan facility.

The above amounts are net of non-participation by Lehman Brothers Commercial Bank. At June 30, 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 June 30, 2009 the available capacity under the revolving credit facility was $188.5 million.

Other Agreements

As of June 30, 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.

10. 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 contract type. 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 primarily utilize crude oil swaps and following our acquisition of the NGL Hedge on April 1, 2009, NGL derivatives to mitigate a significant portion of our commodity price exposure for propane and heavier NGLs. Historically, there has been a relationship 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 a portion of NGL price risks. 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 relationship. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2014 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 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 in the current period 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 and connected storage to maximize 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.

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 effective event of default under 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. These provisions apply if we default in making timely payments under those agreements and the amount of the default is above certain predefined thresholds, which are significantly high, and are generally consistent with the terms of our credit agreement. As of June 30, 2009, we are not a party to any agreements that would be subject to these provisions other than our credit agreement.

Our commodity derivative contracts that are not governed by ISDA contracts 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 June 30, 2009, we had approximately $36.7 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any 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 contracts permit 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 June 30, 2009 if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of June 30, 2009, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $28.9 million.

As of June 30, 2009 our interest rate swaps were in a net liability position of approximately $30.6 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 June 30, 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 June 30, 2009, we had no cash collateral posted with counterparties to our commodity derivative instruments.

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Summarized Derivative Information

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

	June 30, 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	(29.8)	(38.7)
Total AOCI	$ (31.0)	$ (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	June 30, 2009	December 31, 2008	Balance Sheet Line Item	June 30, 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	$ (18.7)	$ (16.5)
Unrealized gains on derivative instruments – long term	0.9	—	Unrealized losses on derivative instruments – long term	(12.8)	(22.8)
	$ 0.9	$ —		$ (31.5)	$ (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	$ 5.9	$ 15.4	Unrealized losses on derivative instruments – current	$ (7.0)	$ (1.2)
Unrealized gains on derivative instruments – long term	2.9	8.6	Unrealized losses on derivative instruments – long term	(30.8)	(3.2)
	$ 8.8	$ 24.0		$ (37.8)	$ (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	
	Three Months Ended June 30,					
	2009	2008	2009	2008	2009	2008
	(Millions)		(Millions)		(Millions)	
Interest rate derivatives	$ 4.8	$ 12.6	$ (4.6)	$ (2.2)(b)	$ —	$ — (b)(c)
Commodity derivatives	$ —	$ —	$ (0.1)	$ (0.1)(a)	$ —	$ — (a)(c)

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	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
	Six Months Ended June 30,						
	2009	2008	2009	2008	2009	2008	
	(Millions)		(Millions)		(Millions)		(Millions)
Interest rate derivatives	$ 0.3	$ (1.1)	$ (8.6)	$ (2.3)(b)	$ —	$ — (b)(c)	$ (17.9)
Commodity derivatives	$ —	$ —	$ (0.6)	$ (0.4)(a)	$ —	$ — (a)(c)	$ (0.7)

(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.
(c) For the three and six months ended June 30, 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Millions)			
Third party:				
Realized	$ 7.9	$ (14.4)	$ 14.8	$ (21.4)
Unrealized	(51.9)	(170.5)	(51.1)	(201.3)
Losses from commodity derivative activity, net	$ (44.0)	$ (184.9)	$ (36.3)	$ (222.7)
Affiliates:				
Realized	$ 0.3	$ (2.6)	$ (0.4)	$ (4.7)
Unrealized	(2.2)	0.2	(2.2)	3.0
Losses from commodity derivative activity, net — affiliates	$ (1.9)	$ (2.4)	$ (2.6)	$ (1.7)

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.

	June 30, 2009		
	Crude Oil	Natural Gas	Natural Gas Liquids
Year of Expiration	Net Long (Short) Position (Bbls)	Net Long (Short) position (MMbtu)	Net Long (Short) Position (Bbls)
2009	(450,800)	(1,350,000)	(111,621)
2010	(950,225)	(2,023,500)	(74,001)
2011	(949,000)	(1,314,000)	—
2012	(777,750)	(1,317,600)	—
2013	(748,250)	(730,000)	—
2014	(365,000)	—	—

We periodically enter into interest rate swap agreements to mitigate our floating rate interest exposure. As of June 30, 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.

11. 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 April 2009, we issued 3,500,000 Class D units valued at $49.7 million. The Class D units were issued to DCP LP Holdings, LP and DCP Midstream GP, LP in consideration for an additional 25.1% interest in East Texas and the NGL Hedge. The Class D units represent limited partnership interests in the partnership.

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

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

- less the amount of cash reserves established by the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; 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 of approximately 1% and limited partner interest of 1% as of June 30, 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Class D Units — The Class D Units will be eligible to receive distributions of Available Cash in August 2009, including the payment of the second quarter distribution. The Class D Units otherwise generally have the same rights as the Partnership's outstanding Common Units and will convert into the Partnership's Common Units on a one for one basis on August 17, 2009.

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)
May 15, 2009	$ 0.600	$ 20.1
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

12. 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 and six months ended June 30, 2009 and 2008, no additional earnings were allocated to the general partner.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Millions)			
Net loss attributable to partners	$ (42.1)	$ (153.1)	$ (21.0)	$ (153.0)
Net (income) loss attributable to predecessor operations	—	(6.2)	1.0	(12.8)
Net loss attributable to the partnership	(42.1)	(159.3)	(20.0)	(165.8)
General partner interest in net income or net loss	(2.7)	(0.7)	(5.9)	(3.4)
Net loss available to limited partners	$ (44.8)	$ (160.0)	$ (25.9)	$ (169.2)
Net loss per LPU — basic and diluted	$ (1.41)	$ (5.67)	$ (0.86)	$ (6.36)

13. 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 condensed 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. We have negotiated a resolution of this matter with the CDPHE for approximately $186,000, which will consist of a monetary penalty and an agreement to perform a supplemental environmental project.

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., or El Paso, 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. During the second quarter of 2009 we filed an appeal in the 14th Court of Appeals, Texas and will continue to defend ourselves vigorously against this claim. El Paso has filed an additional lawsuit in Louisiana, claiming damages for the same claims as the Texas matter, but for periods prior to our ownership of the asset. We intend to file motions to remove us from the Louisiana matter. As a result of the jury verdict, we recorded a contingent liability of $2.5 million in the fourth quarter of 2008 for this matter, which is included in other long-term liabilities in the condensed consolidated balance sheets as of June 30, 2009 and in other current liabilities in the condensed consolidated balance sheets as of December 31, 2008.

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.

Insurance — We renewed our insurance policies in June and July 2009 for the 2009-2010 insurance year. Previously, we carried insurance jointly with DCP Midstream, LLC. Following our 2009 renewals, we now contract with a third party insurer separately from DCP Midstream for: (1) statutory workers' compensation insurance; (2) automobile liability insurance for all owned, non-owned and hired vehicles; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) property insurance, which covers replacement value of all real and personal property and

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includes business interruption/extra expense. However, we are still jointly insured with DCP Midstream, LLC for directors and officers insurance covering our directors and officers for acts related to our business activities. As a result of separating this insurance, we have reduced the excess liability and property limits to match the type and size of assets covered by this insurance. These changes have not resulted in any material change to the premiums we will pay in the 2009-2010 insurance year. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies that are of similar size to us and with similar types of operations.

Discovery's previous property insurance policy expired in June 2009. Our insurance on Discovery for the 2009-2010 insurance year covers onshore and offshore property, onshore named windstorm and onshore business interruption insurance. The availability of named windstorm insurance has been significantly reduced as a result of higher industry-wide damage claims in past years. Additionally, the named windstorm insurance that is available comes at significantly higher premium amounts, higher deductibles and lower coverage limits. Consequently, Discovery elected to not purchase offshore named windstorm insurance coverage for the 2009-2010 insurance year.

14. 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 system; (2) our Southern Oklahoma system; (3) our 40% limited liability company interest in Discovery; (4) our Colorado and Wyoming systems; (5) our East Texas system; and (6) 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.

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The following tables set forth our segment information:

Three Months Ended June 30, 2009

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenues	$ 103.3	$ 46.9	$ 1.8	$ —	$ 152.0
Gross margin (a)	$ (3.4)	$ 5.8	$ 1.3	$ —	$ 3.7
Operating and maintenance expense	(14.5)	(2.4)	(0.2)	—	(17.1)
Depreciation and amortization expense	(15.4)	(0.4)	(0.4)	(0.1)	(16.3)
General and administrative expense	—	—	—	(7.1)	(7.1)
Earnings from equity method investments	3.3	—	0.4	—	3.7
Interest income	—	—	—	0.1	0.1
Interest expense	—	—	—	(7.0)	(7.0)
Income tax expense (b)	—	—	—	—	—
Net (loss) income	(30.0)	3.0	1.1	(14.1)	(40.0)
Net income attributable to noncontrolling interests	(2.1)	—	—	—	(2.1)
Net (loss) income attributable to partners	$ (32.1)	$ 3.0	$ 1.1	$(14.1)	$ (42.1)
Non-cash derivative mark-to-market (c)	$ (54.0)	$ (0.1)	$ —	$ (0.1)	$ (54.2)
Capital expenditures	$ 62.1	$ 0.3	$ —	$ —	$ 62.4

Three Months Ended June 30, 2008

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenues	$ 247.3	$ 94.3	$ 2.7	$ —	$ 344.3
Gross margin (a)	$ (106.4)	$ 2.4	$ 1.9	$ —	$(102.1)
Operating and maintenance expense	(16.4)	(2.7)	(0.2)	—	(19.3)
Depreciation and amortization expense	(12.4)	(0.3)	(0.3)	—	(13.0)
General and administrative expense	—	—	—	(7.8)	(7.8)
Other	—	1.5	—	—	1.5
Earnings from equity method investments	6.9	—	0.2	—	7.1
Interest income	—	—	—	2.0	2.0
Interest expense	—	—	—	(7.9)	(7.9)
Income tax expense (b)	—	—	—	(0.3)	(0.3)
Net (loss) income	(128.3)	0.9	1.6	(14.0)	(139.8)
Net income attributable to noncontrolling interests	(13.3)	—	—	—	(13.3)
Net (loss) income attributable to partners	$ (141.6)	$ 0.9	$ 1.6	$(14.0)	$(153.1)
Non-cash derivative mark-to-market (c)	$ (170.2)	$ (0.2)	$ —	$ 0.1	$(170.3)
Capital expenditures	$ 14.4	$ 1.2	$ 0.1	$ —	$ 15.7

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Six Months Ended June 30, 2009

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics (Millions)	Other	Total
Total operating revenues	$ 253.1	$ 179.7	$ 3.6	$ —	$ 436.4
Gross margin (a)	$ 37.0	$ 31.6	$ 2.6	$ —	$ 71.2
Operating and maintenance expense	(27.7)	(5.1)	(0.5)	—	(33.3)
Depreciation and amortization expense	(29.3)	(0.7)	(0.8)	(0.1)	(30.9)
General and administrative expense	—	—	—	(15.7)	(15.7)
Earnings from equity method investments	1.8	—	0.8	—	2.6
Interest income	—	—	—	0.3	0.3
Interest expense	—	—	—	(14.3)	(14.3)
Income tax expense (b)	—	—	—	(0.1)	(0.1)
Net (loss) income	(18.2)	25.8	2.1	(29.9)	(20.2)
Net income attributable to noncontrolling interests	(0.8)	—	—	—	(0.8)
Net (loss) income attributable to partners	$ (19.0)	$ 25.8	$ 2.1	$(29.9)	$ (21.0)
Non-cash derivative mark-to-market (c)	$ (53.9)	$ 0.1	$ —	$ (0.2)	$ (54.0)
Capital expenditures	$ 118.0	$ 0.4	$ —	$ —	$ 118.4

Six Months Ended June 30, 2008

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics (Millions)	Other	Total
Total operating revenues	$ 522.3	$ 296.0	$ 5.3	$ —	$ 823.6
Gross margin (a)	$ (68.8)	$ 11.0	$ 3.8	$ —	$ (54.0)
Operating and maintenance expense	(31.5)	(5.4)	(0.4)	—	(37.3)
Depreciation and amortization expense	(24.4)	(0.6)	(0.7)	—	(25.7)
General and administrative expense	—	—	—	(15.4)	(15.4)
Other	—	1.5	—	—	1.5
Earnings from equity method investments	17.2	—	0.6	—	17.8
Interest income	—	—	—	3.7	3.7
Interest expense	—	—	—	(16.0)	(16.0)
Income tax expense (b)	—	—	—	(0.6)	(0.6)
Net (loss) income	(107.5)	6.5	3.3	(28.3)	(126.0)
Net income attributable to noncontrolling interests	(27.0)	—	—	—	(27.0)
Net (loss) income attributable to partners	$ (134.5)	$ 6.5	$ 3.3	$(28.3)	$(153.0)
Non-cash derivative mark-to-market (c)	$ (201.2)	$ 2.5	$ —	$ (0.2)	$(198.9)
Capital expenditures	$ 29.0	$ 2.0	$ 0.2	$ —	$ 31.2

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	June 30, 2009	December 31, 2008
	(Millions)	
Segment long-term assets:		
Natural Gas Services	$1,141.9	$ 1,045.9
Wholesale Propane Logistics	54.0	54.3
NGL Logistics	33.3	33.8
Other (d)	40.3	70.3
Total long-term assets	1,269.5	1,204.3
Current assets	121.9	215.4
Total assets	$1,391.4	$ 1,419.7

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

(b) Income tax expense relates primarily to the Texas margin tax and 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.

15. Supplemental Cash Flow Information

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Millions)	
Cash paid for interest, net of amounts capitalized	$6.2	$14.3
Non-cash investing and financing activities:		
Non-cash increase (decrease) in property, plant and equipment	$2.4	$ (7.8)

16. Subsequent Events

We have evaluated subsequent events occurring through August 10, 2009, the date the financial statements were issued.

On July 28, 2009, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on August 14, 2009 to unitholders of record on August 7, 2009.

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. In April 2009, we acquired an additional 25.1% interest in DCP East Texas Holdings, LLC, or East Texas, and a fixed price natural gas liquids derivative by NGL component for the period of April 2009 to March 2010, or NGL Hedge, from DCP Midstream, LLC, in a transaction among entities under common control. Accordingly, our financial information includes the historical results of East Texas for all periods presented. The NGL Hedge was entered into on the date of the transaction. Accordingly, our financial information include the results of the NGL Hedge prospectively from April 1, 2009. We refer to the assets, liabilities and operations of East Texas, prior to our acquisition of an additional 25.1% from DCP Midstream, LLC in April 2009, collectively as our "predecessor." Prior to this transaction we owned a 25.0% limited liability company interest in East Texas, which we accounted for under the equity method of accounting. Subsequent to this transaction we own a 50.1% interest in East Texas, and account for East Texas as a consolidated subsidiary.

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 system; (2) our Southern Oklahoma system; (3) our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery; (4) our Colorado and Wyoming systems; (5) our East Texas system; and (6) 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 July 28, 2009, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on August 14, 2009 to unitholders of record on August 7, 2009.

In May 2009, service was initiated on our new 30-mile, 20-inch gathering pipeline for our East Texas system, with a designed capacity of 175 MMcf/d. The pipeline is currently flowing approximately 30 MMcf/d that was previously flowing to another party.

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 convert into common units in August 2009 and will be eligible to receive distributions including 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 account for 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 May 2009, Chevron announced that they commenced production at Tahiti, one of the largest oil and gas fields in the Gulf of Mexico, and expect gas flow of approximately 70 MMcf/d by the end of the year. The Tahiti asset has increased our volumes at Discovery, and is currently flowing at approximately 60 MMcf/d. In addition, we received a distribution from Discovery of $2.4 million for the second quarter of 2009 in June, which reflects a change in Discovery's LLC Agreement to make cash distributions for a given quarter in the same quarter.

We are actively pursuing full reimbursement of our costs and lost margin associated with a fire at our East Texas natural gas processing complex and residue gas delivery system known as the Carthage Hub from the responsible third party.

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 related 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 explore for and produce natural gas. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close relationship. Due to our hedging program, changes in the relationship 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 investment, through 2014 with fixed price natural gas crude oil and NGL 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 and NGL 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.

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 further reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall below demand levels.

In April 2009, we completed the acquisition of an additional 25.1% interest in East Texas from DCP Midstream, LLC, which results in us owning a 50.1% interest in East Texas. Prior to this transaction, we accounted for our interest in East Texas under the equity method of accounting. As a result of our owning in excess of 50%, and because the transaction was between entities under common control, we are required to present results of operations, including all historical periods, on a consolidated basis. Therefore, these results as presented are different from those originally reported in 2008, which excluded the impact of this transaction.

Additionally, note that while we utilize commodity derivative instruments to help stabilize distributable cash flows for our ownership in East Texas as well as all other natural gas services assets, the portion of East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 75% of East Texas unhedged in all periods prior to the second quarter of 2009 and 49.9% of East Texas unhedged for all periods subsequent to the first quarter of 2009.

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 use physical inventory, physical purchase agreements and financial derivative instruments, with DCP Midstream, LLC or third parties, which typically match the quantities of propane subject to these fixed price sales agreements to mitigate our commodity price risk. Our results may also be impacted as a result of non-cash lower of cost or market inventory adjustments, which occur when the market value of propane declines below our inventory value. We generally recover lower of cost or market inventory adjustments in subsequent periods through the sale of inventory. There may be positive or negative impacts on sales volumes and gross margin from supply disruptions and 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 is impacted by natural gas volumes received by processing plants connected to our NGL pipelines and may also be negatively impacted as a result of our customers operating their processing plants in ethane rejection mode. 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 downturn in the economy is causing a reduction in 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 half of 2009. To date, we have experienced lower gas throughput volumes at certain of our natural gas assets. Throughput volumes could decline further 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 past 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, Discovery also generates 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 Discovery. 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 one primary supplier of natural gas in our Natural Gas Services segment represented approximately 16% of the 953 MMcf/d of natural gas supplied to our systems during the six months ended June 30, 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 97% of our propane supplied during the six months ended June 30, 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. DCP Midstream, LLC provides 100% of volumes transported on the Seabreeze and Wilbreeze pipelines. 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, 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) adjusted EBITDA; and (5) distributable cash flow. Gross margin, segment gross margin, adjusted segment gross margin, 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.

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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of net loss attributable to partners to gross margin:				
Net loss attributable to partners	$(42.1)	$(153.1)	$(21.0)	$(153.0)
Interest expense	7.0	7.9	14.3	16.0
Income tax expense	—	0.3	0.1	0.6
Operating and maintenance expense	17.1	19.3	33.3	37.3
Depreciation and amortization expense	16.3	13.0	30.9	25.7
General and administrative expense	7.1	7.8	15.7	15.4
Other	—	(1.5)	—	(1.5)
Interest income	(0.1)	(2.0)	(0.3)	(3.7)
Earnings from equity method investments	(3.7)	(7.1)	(2.6)	(17.8)
Net income attributable to noncontrolling interests	2.1	13.3	0.8	27.0
Gross margin	$ 3.7	$ (102.1)	$ 71.2	$ (54.0)
Non-cash derivative mark-to-market (a)	$(54.2)	$(170.3)	$(54.0)	$(198.9)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of segment net income (loss) attributable to partners to segment gross margin:				
Natural Gas Services segment:				
Segment net loss attributable to partners	$ (32.1)	$ (141.6)	$ (19.0)	$ (134.5)
Operating and maintenance expense	14.5	16.4	27.7	31.5
Depreciation and amortization expense	15.4	12.4	29.3	24.4
Earnings from equity method investment	(3.3)	(6.9)	(1.8)	(17.2)
Net income attributable to noncontrolling interests	2.1	13.3	0.8	27.0
Segment gross margin	$ (3.4)	$ (106.4)	$ 37.0	$ (68.8)
Non-cash derivative mark-to-market (a)	$ (54.0)	$ (170.2)	$ (53.9)	$ (201.2)
Wholesale Propane Logistics segment:				
Segment net income attributable to partners	$ 3.0	$ 0.9	$ 25.8	$ 6.5
Operating and maintenance expense	2.4	2.7	5.1	5.4
Depreciation and amortization expense	0.4	0.3	0.7	0.6
Other	—	(1.5)	—	(1.5)
Segment gross margin	$ 5.8	$ 2.4	$ 31.6	$ 11.0
Non-cash derivative mark-to-market (a)	$ (0.1)	$ (0.2)	$ 0.1	$ 2.5
NGL Logistics segment:				
Segment net income attributable to partners	$ 1.1	$ 1.6	$ 2.1	$ 3.3
Operating and maintenance expense	0.2	0.2	0.5	0.4
Depreciation and amortization expense	0.4	0.3	0.8	0.7
Earnings from equity method investment	(0.4)	(0.2)	(0.8)	(0.6)
Segment gross margin	$ 1.3	$ 1.9	$ 2.6	$ 3.8

(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 June 30, 2009 and 2008, we incurred $2.4 million and $2.5 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $2.7 million and $2.3 million, respectively. During the six months ended June 30, 2009 and 2008, we incurred $4.8 million and $4.9 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $5.6 million and $5.0 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.

The Omnibus Agreement was not amended following our acquisition of an additional 25.1% interest in East Texas on April 1, 2009. East Texas incurs general and administrative expenses directly from DCP Midstream, LLC. During the three months ended June 30, 2009 and 2008 East Texas incurred $2.2 million and $2.1 million, respectively, for general and administrative expenses from DCP Midstream, LLC. During the six months ended June 30, 2009 and 2008 East Texas incurred $4.4 million and $4.1 million, respectively, for general and administrative expenses from DCP Midstream, LLC.

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.

Discovery pays fees to Williams, for direct general and administrative costs incurred on their behalf. These fees reduce the amount of cash available from Discovery for distribution to us.

Adjusted EBITDA and Distributable Cash Flow — We define adjusted EBITDA as net income or loss attributable to partners less interest income, noncontrolling interest in depreciation and income tax expense and non-cash commodity derivative gains, plus interest expense, income tax expense, depreciation and amortization expense and non-cash commodity derivative losses. Adjusted EBITDA is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures;
- 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 adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner.

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.

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 six months ended June 30, 2009 are the same as those described in our 2008 Form 10-K.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2009 and 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2009 vs. 2008		Variance Six Months 2009 vs. 2008	
	2009 (a)	2008 (b)	2009 (a)(b)	2008 (b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Natural Gas Services (c)	$ 103.3	$ 247.3	$ 253.1	$ 522.3	$ (144.0)	(58)%	$ (269.2)	(52)%
Wholesale Propane Logistics	46.9	94.3	179.7	296.0	(47.4)	(50)%	(116.3)	(39)%
NGL Logistics	1.8	2.7	3.6	5.3	(0.9)	(33)%	(1.7)	(32)%
Total operating revenues	152.0	344.3	436.4	823.6	(192.3)	(56)%	(387.2)	(47)%
Gross margin (d):								
Natural Gas Services	(3.4)	(106.4)	37.0	(68.8)	103.0	97%	105.8	*
Wholesale Propane Logistics	5.8	2.4	31.6	11.0	3.4	142%	20.6	187%
NGL Logistics	1.3	1.9	2.6	3.8	(0.6)	(32)%	(1.2)	(32)%
Total gross margin	3.7	(102.1)	71.2	(54.0)	105.8	*	125.2	*
Operating and maintenance expense	(17.1)	(19.3)	(33.3)	(37.3)	(2.2)	(11)%	(4.0)	(11)%
Depreciation and amortization expense	(16.3)	(13.0)	(30.9)	(25.7)	3.3	25%	5.2	20%
General and administrative expense	(7.1)	(7.8)	(15.7)	(15.4)	(0.7)	(9)%	0.3	2%
Other	—	1.5	—	1.5	(1.5)	(100)%	(1.5)	(100)%
Earnings from equity method investments (d)	3.7	7.1	2.6	17.8	(3.4)	(48)%	(15.2)	(85)%
Interest income	0.1	2.0	0.3	3.7	(1.9)	(95)%	(3.4)	(92)%
Interest expense	(7.0)	(7.9)	(14.3)	(16.0)	(0.9)	(11)%	(1.7)	(11)%
Income tax expense	—	(0.3)	(0.1)	(0.6)	(0.3)	(100)%	(0.5)	(83)%
Net income attributable to noncontrolling interests	(2.1)	(13.3)	(0.8)	(27.0)	(11.2)	(84)%	(26.2)	(97)%
Net loss attributable to partners	$ (42.1)	$ (153.1)	$ (21.0)	$ (153.0)	$ 111.0	73%	$ 132.0	86%
Operating data:								
Natural gas throughput (MMcf/d) (e)	1,108	980	1,051	980	128	13%	71	7%
NGL gross production (Bbls/d) (e)	28,584	30,659	25,208	31,702	(2,075)	(7)%	(6,494)	(20)%
Propane sales volume (Bbls/d)	13,912	14,442	25,502	24,178	(530)	(4)%	1,324	5%
NGL pipelines throughput (Bbls/d) (e)	26,850	34,286	25,409	33,081	(7,436)	(22)%	(7,672)	(23)%

* Percentage change is not meaningful.

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

(b) In April 2009, we completed the acquisition of an additional 25.1% interest in East Texas from DCP Midstream, LLC, which results in us owning a 50.1% interest in East Texas. Prior to this transaction, we accounted for our interest in East Texas under the equity method of accounting. As a result of our owning in excess of 50%, and because the transaction was between entities under common control, we are required to present results of operations, including all historical periods, on a consolidated basis. Therefore, these results as presented are different from those originally reported in 2008, which excluded the impact of this transaction.

Additionally, note that while we utilize commodity derivative instruments to help stabilize distributable cash flows for our ownership in East Texas as well as all other natural gas services assets, the portion of East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 75% of East Texas unhedged in all periods prior to the second quarter of 2009 and 49.9% of East Texas unhedged for all periods subsequent to the first quarter of 2009.

Our gross margin for our Natural Gas Services segment changed from a loss of $146.2 million and $148.7 million as previously reported in 2008, to a loss of $106.4 million and $68.8 million as currently reported, for the three and six months ended June 30, 2008, respectively.

(c) Includes the effect of the acquisition of the NGL Hedge, contributed by DCP Midstream, LLC in April 2009. The NGL Hedge is a fixed price natural gas liquids derivative by NGL component for the period April 2009 to March 2010.

(d) 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.

(e) Includes our proportionate share of the throughput volumes and NGL production of Collbran, Jackson, East Texas, Black Lake and Discovery and our proportionate earnings of Black Lake 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.

Three Months Ended June 30, 2009 vs. Three Months Ended June 30, 2008

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

- $48.5 million decrease primarily attributable to lower propane prices, for our Wholesale Propane Logistics segment;
- $288.0 million decrease primarily attributable to decreased commodity prices and a decrease in transport volumes, partially offset by 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
- $0.7 million decrease due to decreased throughput volumes, as well as a decline in volumes from connected plants for our NGL Logistics segment; partially offset by
- $141.5 million increase related to commodity derivative activity, resulting from the following:
  - a loss of $45.9 million in 2009 and a loss of $187.3 million in 2008, resulting in a decrease in losses of $141.4 million, which is included in losses from commodity derivative activity. This decrease in losses includes a decrease in unrealized losses of $116.2 million due to forward prices of commodities generally being lower in 2009 compared to 2008 and an increase in realized cash settlement gains of $25.2 million due to average prices of commodities generally being lower in 2009 compared to 2008; and
  - a $0.1 million decrease in unrealized loss, which is included in sales of natural gas, NGLs and condensate; and
- $3.4 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:

- $103.0 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 as well as lower processing margins; and
- $3.4 million increase for our Wholesale Propane Logistics segment as a result of increased per unit margins; partially offset by
- $0.6 million decrease for our NGL Logistics segment, primarily attributable to decreased throughput, as well as a decline in volumes from connected 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 decreased in 2009 compared to 2008, primarily as a result of our cost reduction initiatives, partially offset by the MPP acquisition.

Earnings from Equity Method Investments — Earnings from equity method investments decreased in 2009 compared to 2008, primarily due to decreased equity earnings from Discovery of $3.6 million.

Noncontrolling Interest in Income — Noncontrolling interest in income represents the noncontrolling interest holders' portion of the net income of East Texas, 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 and our East Texas expansion project.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

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

- $459.3 million decrease primarily attributable to decreased commodity prices and a decrease in transport volumes, partially offset by 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
- $116.4 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;
- $1.3 million decrease due to decreased throughput volumes resulting from ethane rejection at certain connected processing plants during the first quarter and lower commodity prices in our NGL Logistics segment; partially offset by
- $185.3 million increase related to commodity derivative activity, resulting from the following:
  - a loss of $38.9 million in 2009 and a loss of $224.4 million in 2008, resulting in a decrease in losses of $185.5 million, which is included in losses from commodity derivative activity. This decrease in losses includes a decrease in unrealized gains of $145.0 million due to forward prices of commodities generally being lower in 2009 compared to 2008 and an increase in realized cash settlement gains of $40.5 million due to average prices of commodities generally being lower in 2009 compared to 2008; partially offset by
  - a $0.2 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate; and
- $4.5 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:

- $105.8 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 as well as lower processing margins; and

- $20.6 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
- $1.2 million decrease for our NGL Logistics segment, primarily attributable to decreased throughput volumes resulting from ethane rejection at certain connected processing plants during the first quarter, as well as a decline in volumes from connected plants and lower commodity prices.

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, partially offset by our cost reduction initiatives.

*Earnings from Equity Method Investment*s — Earnings from equity method investments decreased in 2009 compared to 2008, primarily due to the impact of hurricanes and lower per unit margins on Discovery. 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 represents the noncontrolling interest holders' portion of the net income or loss of our East Texas, 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.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition and our East Texas expansion project.

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Results of Operations — Natural Gas Services Segment

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

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2009 vs. 2008		Variance Six Months 2009 vs. 2008	
	2009 (a)	2008 (b)	2009 (a)(b)	2008 (b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 126.5	$ 414.4	$ 250.2	$ 709.7	$ (287.9)	(69)%	$ (459.5)	(65)%
Transportation, processing and other	22.6	18.1	41.7	35.9	4.5	25%	5.8	16%
Losses from commodity derivative activity (c)	(45.8)	(185.2)	(38.8)	(223.3)	(139.4)	(75)%	(184.5)	(83)%
Total operating revenues	103.3	247.3	253.1	522.3	(144.0)	(58)%	(269.2)	(52)%
Purchases of natural gas and NGLs	106.7	353.7	216.1	591.1	(247.0)	(70)%	(375.0)	(63)%
Segment gross margin (d)	(3.4)	(106.4)	37.0	(68.8)	103.0	97%	105.8	*
Operating and maintenance expense	(14.5)	(16.4)	(27.7)	(31.5)	(1.9)	(12)%	(3.8)	(12)%
Depreciation and amortization expense	(15.4)	(12.4)	(29.3)	(24.4)	3.0	24%	4.9	20%
Earnings from equity method investment (e)	3.3	6.9	1.8	17.2	(3.6)	(52)%	(15.4)	(90)%
Segment net loss	(30.0)	(128.3)	(18.2)	(107.5)	98.3	77%	89.3	83%
Segment net income attributable to noncontrolling interests	(2.1)	(13.3)	(0.8)	(27.0)	(11.2)	(84)%	(26.2)	(97)%
Segment net loss attributable to partners	$ (32.1)	$ (141.6)	$ (19.0)	$ (134.5)	$ 109.5	77%	$ 115.5	86%
Operating data:								
Natural gas throughput (MMcf/d) (d)	1,108	980	1,051	980	128	13%	71	7%
NGL gross production (Bbls/d) (d)	28,584	30,659	25,208	31,702	(2,075)	(7)%	(6,494)	(20)%

* Percentage change is not meaningful.

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

(b) In April 2009, we completed the acquisition of an additional 25.1% interest in East Texas from DCP Midstream, LLC, which results in us owning a 50.1% interest in East Texas. Prior to this transaction, we accounted for our interest in East Texas under the equity method of accounting. As a result of our owning in excess of 50%, and because the transaction was between entities under common control, we are required to present results of operations, including all historical periods, on a consolidated basis. Therefore, these results as presented are different from those originally reported in 2008, which excluded the impact of this transaction.

Additionally, note that while we utilize commodity derivative instruments to help stabilize distributable cash flows for our ownership in East Texas as well as all other natural gas services assets, the portion of East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 75% of East Texas unhedged in all periods prior to the second quarter of 2009 and 49.9% of East Texas unhedged for all periods subsequent to the first quarter of 2009.

Our gross margin for our Natural Gas Services segment changed from a loss of $146.2 million and $148.7 million as previously reported in 2008, to a loss of $106.4 million and $68.8 million as currently reported, for the three and six months ended June 30, 2008, respectively.

(c) Includes the effect of the acquisition of the NGL Hedge, contributed by DCP Midstream, LLC in April 2009. The NGL Hedge is a fixed price natural gas liquids derivative by NGL component for the period April 2009 to March 2010.

(d) 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.

(e) Includes our proportionate share of the throughput volumes and NGL production of Collbran, Jackson East Texas and Discovery and our proportionate share of the earnings of 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 June 30, 2009 vs. Three Months Ended June 30, 2008

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

- $233.5 million decrease attributable to decreased commodity prices;
- $54.5 million decrease, primarily due to a decrease in transport volumes and, partially offset by a January 1, 2009 amendment to a contract with an affiliate such that certain Pelico revenues changed from a net presentation to a gross presentation; partially offset by
- $139.5 million increase related to commodity derivative activity, resulting from the following:
  - a loss of $45.8 million in 2009 and a loss of $185.2 million in 2008, resulting in a decrease in losses of $139.4 million, which is included in losses from commodity derivative activity. This decrease in losses includes a decrease in unrealized losses of $116.1 million due to forward prices of commodities generally being lower in 2009 compared to 2008, and an increase in realized cash settlement gains of $23.3 million due to average prices of commodities generally being lower in 2009 compared to 2008; and
  - a $0.1 million decrease in unrealized loss, which is included in sales of natural gas, NGLs and condensate;
- $4.5 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:

- $139.5 million increase related to commodity derivative activity, as discussed in the Operating Revenues section above; and
- $5.0 million increase primarily as a result of the MPP acquisition; partially offset by
- $34.1 million decrease due to lower commodity prices; and
- $7.4 million decrease due to lower natural gas volumes and NGL production, as well as lower processing margins.

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 and our East Texas expansion project.

Earnings from Equity Method Investment — Earnings from equity method investment decreased in 2009 compared to 2008, primarily due to the impact of lower per-unit margins on Discovery. Settlements related to our commodity derivatives on our equity method investment are included in segment gross margin. Decreased equity earnings were primarily as a result of the following variances, representing 100% of the earnings drivers for Discovery: a decrease in Discovery’s net income of $7.6 million, due primarily to $12.0 million lower NGL sales margins resulting from lower average per-unit margins on higher volumes. These decreases were partially offset by $2.0 million lower depreciation and accretion expense and $1.8 million lower operating and maintenance expense.

Noncontrolling Interest in Income — Noncontrolling interest in income represents the noncontrolling interest holders’ portion of the net income of our East Texas, 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 across our Northern Louisiana system, as well as at East Texas and Discovery. NGL production decreased in 2009 compared to 2008, due primarily to decreased NGL production at East Texas.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

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

- $369.2 million decrease attributable to decreased commodity prices;
- $90.1 million decrease in transport volumes, partially offset by a January 1, 2009 amendment to a contract with an affiliate such that certain Pelico revenues changed from a net presentation to a gross presentation; partially offset by
- $184.3 million increase related to commodity derivative activity, resulting from the following:
  - a loss of $38.8 million in 2009 and a loss of $223.3 million in 2008, resulting in a decrease in losses of $184.5 million, which is included in losses from commodity derivative activity. This increase includes a decrease in unrealized losses of $147.4 million due to forward prices of commodities generally being lower in 2009 compared to 2008, and an increase in realized cash settlement gains of $37.1 million due to average prices of commodities generally being lower in 2009 compared to 2008; partially offset by
  - a $0.2 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate;
- $5.8 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:

- $184.3 million increase related to commodity derivative activity, as discussed in the Operating Revenues section above; and
- $9.9 million increase primarily as a result of the MPP acquisition, partially offset by lower processing margins; partially offset by
- $60.6 million decrease due to lower commodity prices; and
- $27.8 million decrease due to lower natural gas volumes and NGL production, as well as lower processing margins.

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 and our East Texas expansion project.

Earnings from Equity Method Investment — Earnings from equity method investment decreased in 2009 compared to 2008, primarily due to the impact of lower per-unit margins and hurricanes on Discovery. Settlements related to our commodity derivatives on our equity method investment are included in segment gross margin. Decreased equity earnings were primarily as a result of the following variances, representing 100% of the earnings drivers for Discovery: a decrease in Discovery’s net income of $35.7 million due primarily to $35.0 million lower NGL sales margins resulting from lower average per-unit margins and lower volumes on NGL equity sales, combined with $5.2 million unfavorable other income/expense – net. These decreases were partially offset by $5.1 million lower depreciation and accretion expense.

Noncontrolling Interest in Income — Noncontrolling interest in income represents the noncontrolling interest holders' portion of the net income or loss of our East Texas, 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 across our Northern Louisiana system and East Texas. NGL production decreased in 2009 compared to 2008, due primarily to decreased NGL production at East Texas and Discovery. Decreased production at East Texas was primarily as a result of production being temporarily shut in following a fire resulting from a third party underground pipeline rupture, during the first quarter of 2009.

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 June 30,		Six Months Ended June 30,		Variance Three Months 2009 vs. 2008		Variance Six Months 2009 vs. 2008	
	2009	2008	2009	2008	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of propane	$ 46.8	$ 95.3	$ 179.6	$ 296.0	$ (48.5)	(51)%	$ (116.4)	(39)%
Other	0.2	1.1	0.2	1.1	(0.9)	(82)%	(0.9)	(82)%
Losses from commodity derivative activity	(0.1)	(2.1)	(0.1)	(1.1)	(2.0)	(95)%	(1.0)	(91)%
Total operating revenues	46.9	94.3	179.7	296.0	(47.4)	(50)%	(116.3)	(39)%
Purchases of propane	41.1	91.9	148.1	285.0	(50.8)	(55)%	(136.9)	(48)%
Segment gross margin (a)	5.8	2.4	31.6	11.0	3.4	142%	20.6	187%
Operating and maintenance expense	(2.4)	(2.7)	(5.1)	(5.4)	(0.3)	(11)%	(0.3)	(6)%
Depreciation and amortization expense	(0.4)	(0.3)	(0.7)	(0.6)	0.1	33%	0.1	17%
Other	—	1.5	—	1.5	(1.5)	(100)%	(1.5)	(100)%
Segment net income attributable to partners	$ 3.0	$ 0.9	$ 25.8	$ 6.5	$ 2.1	233%	$ 19.3	297%
Operating data:								
Propane sales volume (Bbls/d)	13,912	14,442	25,502	24,178	(530)	(4)%	1,324	5%

* 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 June 30, 2009 vs. Three Months Ended June 30, 2008

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

- $45.0 million decrease attributable to lower propane prices;
- $3.5 million decrease attributable to decreased sales volumes; and
- $0.9 million decrease attributable to other fee revenue; partially offset by
- $2.0 million increase related to commodity derivative activity, which represents a decrease in unrealized losses of $0.1 million recognized in 2008, and a decrease in realized cash settlement losses of $1.9 million recognized in 2008.

Purchases of Propane — Purchases of propane decreased in 2009 compared to 2008, primarily due to decreased per unit prices.

Segment Gross Margin — Segment gross margin increased in 2009 compared to 2008, primarily as a result of increased per unit margins and decreased losses related to commodity derivative activity.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

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

- $132.7 million decrease attributable to lower propane prices;
- $0.9 million decrease attributable to other fee revenue; partially offset by
- $16.3 million increase attributable to increased propane sales volumes, driven by an increase in spot sales during the first quarter;
- $1.0 million increase related to commodity derivative activity, which represents decreased realized cash settlement losses of $3.4 million, partially offset by a decrease in unrealized gains of $2.4 million.

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 and decreases in losses related to commodity derivative activity.

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 June 30,		Six Months Ended June 30,		Variance Three Months 2009 vs. 2008		Variance Six Months 2009 vs. 2008	
	2009	2008	2009	2008	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of NGLs	$ 0.4	$ 1.1	$ 1.0	$ 2.3	$ (0.7)	(64)%	$ (1.3)	(57)%
Transportation, processing and other	1.4	1.6	2.6	3.0	(0.2)	(13)%	(0.4)	(13)%
Total operating revenues	1.8	2.7	3.6	5.3	(0.9)	(33)%	(1.7)	(32)%
Purchases of NGLs	0.5	0.8	1.0	1.5	(0.3)	(38)%	(0.5)	(33)%
Segment gross margin (a)	1.3	1.9	2.6	3.8	(0.6)	(32)%	(1.2)	(32)%
Operating and maintenance expense	(0.2)	(0.2)	(0.5)	(0.4)	—	— %	0.1	25%
Depreciation and amortization expense	(0.4)	(0.3)	(0.8)	(0.7)	0.1	33%	0.1	14%
Earnings from equity method investment (b)	0.4	0.2	0.8	0.6	0.2	100%	0.2	33%
Segment net income attributable to partners	$ 1.1	$ 1.6	$ 2.1	$ 3.3	$ (0.5)	(31)%	$ (1.2)	(36)%
Operating data:								
NGL pipelines throughput (Bbls/d) (b)	26,850	34,286	25,409	33,081	(7,436)	(22)%	(7,672)	(23)%

* 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 our proportionate share 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 June 30, 2009 vs. Three Months Ended June 30, 2008

Total Operating Revenues — Total operating revenues decreased in 2009 compared to 2008, primarily due to decreased throughput, as well as a decline in volumes from connected plants.

Purchases of NGLs — Purchases of NGLs decreased in 2009 compared to 2008, due primarily to decreased throughput volumes and lower commodity prices.

Segment Gross Margin — Segment gross margin decreased in 2009 compared to 2008, primarily die to decreased throughput volumes, as well as a decline in volumes from connected plants.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 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 during the first quarter of 2009 and lower commodity prices, as well as a decline in volumes from connected 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 during the first quarter of 2009 and lower commodity prices.

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 during the first quarter of 2009 and lower commodity prices, as well as a decline in volumes from connected plants.

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, crude oil and NGL 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 $789.6 million revolving credit facility and a $35.0 million term loan facility at June 30, 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 August 3, 2009, we had approximately $221.3 million of borrowing capacity 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 August 3, 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 August 3, 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 August 3, 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 June 30, 2009, we had $4.6 million in cash and cash equivalents. Of this balance, as of June 30, 2009, $3.4 million was held by subsidiaries we do not wholly own, which we consolidate in our financial results. Other than the cash held by these subsidiaries, this cash balance was available for general corporate purposes.

We had a working capital deficit of $8.6 million and working capital of $52.2 million as of June 30, 2009 and December 31, 2008, respectively. Excluding derivative working capital liabilities of $19.8 million and $2.3 million, working capital would be $11.2 million and $54.5 million as of June 30, 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.

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

	Six Months Ended June 30,	
	2009	2008
	(Millions)	
Net cash provided by operating activities	$ 51.3	$ 70.8
Net cash used in investing activities	$(99.0)	$(164.0)
Net cash (used in) provided by financing activities	$ (9.6)	$ 90.3

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

We received net cash for settlements of our commodity derivative instruments during the six months ended June 30, 2009 totaling $14.4 million, approximately $3.9 million of which was associated with rebalancing our portfolio. We paid net cash for settlements of our commodity derivative instruments during the six months ended June 30, 2008 totaling $26.1 million.

We received cash distributions from equity method investments of $3.0 million and $21.8 million during the six months ended June 30, 2009 and 2008, respectively. Distributions exceeded earnings by $0.4 million and $4.0 million for the six months ended June 30, 2009 and 2008, respectively.

Net Cash Used in Investing Activities — Net cash used in investing activities during the six months ended June 30, 2009 was comprised of: (1) capital expenditures of $118.4 million (our portion of which was $51.4 million and the noncontrolling interest holders' portion was $67.0 million), which primarily consisted of expenditures for installation of compression and expansion of our East Texas system, our Collbran system, and the completion of pipeline integrity system upgrades to our Douglas system; (2) investments in Discovery of $5.8 million; and (3) a net payment of $0.1 million related to our acquisition of MPP partially offset by (4) net proceeds from sale of available-for-sale securities of $25.0 million; and (5) proceeds from sale of assets of $0.3 million.

Net cash used in investing activities during the six months ended June 30, 2008, was primarily used for: (1) capital expenditures of $31.2 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 (4) net purchases of available-for-sale securities of $120.0 million.

We invested cash in equity method investments of $5.8 million and $1.9 million during the six months ended June 30, 2009 and 2008, respectively, of which $1.6 million and $1.9 million, respectively, was to fund our share of capital expansion projects, and $4.2 million in 2009 was to fund repairs to Discovery following damage caused by Hurricane Ike in 2008.

Net Cash (Used in) Provided by Financing Activities — Net cash used in financing activities during the six months ended June 30, 2009 was comprised of (1) repayments of debt of $86.8 million; (2) distributions to our unitholders and general partner of $40.2 million; and (3) distributions to noncontrolling interests of $4.9 million; partially offset by (4) borrowings of $68.3 million; (5) contributions from non controlling interests of $50.3 million; (6) net changes in advances to predecessor from DCP Midstream, LLC of $3.0 million; and (7) contributions from DCP Midstream, LLC of $0.7 million.

Net cash provided by financing activities during the six months ended June 30, 2008 was comprised of (1) borrowings of $432.0 million; (2) net proceeds from sales of common limited partner units of $132.1 million; (3) contributions from noncontrolling interests of $9.3 million; (4) contributions from DCP Midstream, LLC of $1.9 million, partially offset by; (5) repayments of debt of $402.0 million; (6) distributions to our unitholders and general partner of $35.8 million; (7) distributions to noncontrolling interests of $34.6 million; and (8) net changes in advances from DCP Midstream, LLC relating to our predecessor of $12.6 million.

During the six months ended June 30, 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 $638.3 million and did not exceed $656.8 million. The weighted average indebtedness outstanding for the six months ended June 30, 2009 was $650.5 million.

During the six months ended June 30, 2009 we borrowed (1) $43.3 million under our revolving credit facility for general working capital purposes; and (2) $25.0 million under our revolving credit facility to fund partial repayment of our term loan facility; and we repaid $61.8 million under our revolving credit facility and $25.0 million on our term loan facility.

During the six months ended June 30, 2008, we borrowed (1) $252.0 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 $372.0 million on our revolving credit facility and $30.0 million on our term loan facility.

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. Of the total $118.4 million of capital expenditures for the six months ended June 30, 2009, $51.4 million represents our portion and $67.0 million represents the noncontrolling interest holders’ portion. We paid a total of $51.4 million and $17.1 million for our portion of capital expenditures during the six months ended June 30, 2009 and 2008, respectively. This was made up of our portion of expansion capital expenditures of $42.5 million and $13.9 million, and our portion of maintenance capital expenditures of $8.9 million and $3.2 million for the six months ended June 30, 2009 and 2008, respectively. The amounts we paid for our portion, combined with amounts paid from noncontrolling interests (including DCP Midstream, LLC), amount to our consolidated capital expenditures of $118.4 million and $31.2 million during the six months ended June 30, 2009 and 2008, respectively. These amounts do not reflect capital expenditures for our equity method investments.

We anticipate our portion of maintenance capital expenditures will be approximately $7.0 million and our portion of expansion capital expenditures will be approximately $30.0 million for the remainder of 2009. The board of directors may approve additional growth capital during the year, at their discretion.

Collbran Valley Gas Gathering, LLC, or Collbran, completed the construction of approximately 20 miles of 24-inch diameter gathering pipeline, and is currently setting 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 have invested approximately $5.6 million in 2008 and $27.0 million on this project during the six months ended June 30, 2009.

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. In May 2009, service was initiated on the pipeline. Our net investment is approximately $12.9 million, which represents 25% of the total cost of the project. Of this total, we spent approximately $1.3 million in 2008 and $10.6 million during the six months ended June 30, 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.

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 $40.2 million during the six months ended June 30, 2009, as compared to $35.3 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 $789.6 million revolving credit facility and a $35.0 million term loan facility at June 30, 2009. The Credit Agreement matures on June 21, 2012. As of June 30, 2009, the outstanding balance on the revolving credit facility was $603.0 million and the outstanding balance on the term loan facility was $35.0 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 June 30, 2009 and December 31, 2008, we had outstanding letters of credit issued under the Credit Agreement of $0.3 million.

As of June 30, 2009, the interest rate on our term loan facility was 0.42% and the weighted-average interest rate on our revolving credit facility was 1.03% per annum.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of June 30, 2009, is as follows:

	Payments Due by Period				
	Total	Remainder of 2009	2010-2011	2012-2013	2014 and Thereafter
			(Millions)		
Long-term debt (a)	$ 716.5	$ 13.5	$ 52.2	$ 650.8	$ —
Operating lease obligations	47.6	6.7	22.3	14.9	3.7
Purchase obligations (b)	664.3	92.7	246.3	212.3	113.0
Other long-term liabilities (c)	9.0	—	0.9	0.1	8.0
Total	$1,437.4	$ 112.9	$ 321.7	$ 878.1	$ 124.7

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

(b) Purchase obligations include $10.9 million of purchase orders for capital expenditures and $653.4 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 June 30, 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 $8.2 million of asset retirement obligations and $0.8 million of environmental reserves recognized in the June 30, 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. 168 "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a Replacement of FASB Statement No. 162," **or SFAS 168** — In June 2009, the FASB issued SFAS 168, which establishes the FASB Accounting Standards Codification, or the Codification, as the source of authoritative U.S. Generally Accepted Accounting Principles, or GAAP. The Codification supersedes all existing non-SEC accounting and reporting standards. This SFAS becomes effective for us for annual and interim periods beginning after September 15, 2009 and will have no affect on our condensed consolidated results of operations, cash flows and financial position as a result of adoption.

SFAS No. 167 "Amendments to FASB Interpretation No. 46(R)," **or SFAS 167** — In June 2009, the FASB issued SFAS 167, which requires entities to perform additional analysis of their variable interest entities and consolidation methods. This SFAS becomes effective for us on January 1, 2010 and we are in the process of assessing the impact of this guidance on our condensed consolidated results of operations, cash flows and financial position.

***SFAS No. 165 "Subsequent Events,"* or SFAS 165** — In May 2009, the FASB issued SFAS 165, which sets forth the recognition and disclosure requirements for events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. We adopted SFAS 165 effective June 30, 2009, and there was no effect on our condensed consolidated results of operations, cash flows or financial position as a result of adoption. All appropriate disclosure of subsequent events is made within "Part 1, Notes to the Condensed Consolidated Financial Statements" in this Quarterly Report on form 10-Q.

***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 condensed 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 partners' equity and will present this financial statement on a quarterly basis.

***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 for all financial assets and liabilities. 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 condensed 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. Certain of the markets in which we transact have seen a decrease in overall volume; however, we believe that these markets continue to provide sufficient liquidity such that transactions are executed in an orderly manner at fair value. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated results of operations, cash flows or financial position.

***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 two quarters 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 are subject to the revised disclosure provisions of this FSP. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated results of operations, cash flows or financial position.

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. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed 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 $(5.66) per unit to $(5.67) per unit and from $(6.33) per unit to $(6.36) per unit for the three and six months ended June 30, 2008, respectively.

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 June 30, 2009, the effective weighted-average interest rate on our $603.0 million of outstanding revolver debt was 4.47%, 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 $63.0 million as of June 30, 2009, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.3 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, crude oil and NGL 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 relationship 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 August 3, 2009:

Period	Commodity	Notional Volume	Reference Price	Swap Price Range
July 2009 — December 2009	Natural Gas	2,000 MMBtu/d	Texas Gas Transmission Price (a)	$9.20/MMBtu
July 2009 — December 2009	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
January 2010 — December 2013	Natural Gas	1,000 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
July 2009 — December 2010	Natural Gas	1,634 MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (e)	$3.94/MMBtu
January 2011 — December 2012	Natural Gas	500/ MMBtu/d	IFERC Monthly Index Prices for Colorado Interstate Gas Pipeline (e)	$5.89/MMBtu
January 2010 — December 2010	Natural Gas	1,900 MMBtu/d	Texas Gas Transmission Price (a)	$6.41 -$9.20/MMBtu
January 2011 — December 2012	Natural Gas	1,100 MMBtu/d	Texas Gas Transmission Price (a)	$6.41 - $6.80/MMBtu
July 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 2013	Natural Gas Basis	1,000 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (c)	NYMEX less $0.68/MMBtu
July 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	2,050 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$67.60 - $83.00/Bbl
January 2014 — December 2014	Crude Oil	1,000 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$74.90 - $84.70/Bbl
July 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.

We utilize crude oil and NGL 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.

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	$ 4.5
Crude oil prices	$ 5.00	Barrel	$ 20.7
NGL prices	$ 0.10	Gallon	$ 1.0

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 relationship 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 related 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 relationship 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 relationship.

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 six months ended June 30, 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

Except for the two matters 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. We have negotiated a resolution of this matter with the CDPHE for approximately $186,000, which will consist of a monetary penalty and an agreement to perform a supplemental environmental project.

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. During the second quarter of 2009 we filed an appeal in the 14th Court of Appeals, Texas and will continue to defend ourselves vigorously against this claim. El Paso has filed an additional lawsuit in Louisiana, claiming damages for the same claims as the Texas matter, but for periods prior to our ownership of the asset. We intend to file motions to remove us from the Louisiana matter. As a result of the jury verdict we recorded a contingent liability of $2.5 million in the fourth quarter of 2008 for this matter, which is included in other long-term liabilities in the condensed consolidated balance sheets as of June 30, 2009 and in other current liabilities in the condensed consolidated balance sheets as of December 31, 2008.

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 condensed 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 $5.10 as of June 30, 2009, $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.

We may incur significant costs in the future associated with proposed climate change legislation.

The United States Congress and some states where we have operations are currently considering legislation related to greenhouse gas emissions. In addition, there have recently been international conventions and efforts to establish standards for the reduction of greenhouse gases globally. The United States Congress is currently considering a number of bills that would compel carbon dioxide emission reductions. Some of these proposals include limitations, or caps, on the amount of greenhouse gas that can be emitted, as well as a system of emissions allowances. The current proposal in the United States Congress places the entire burden of obtaining allowances for the carbon content of natural gas liquids, or NGLs, on the midstream natural gas industry. To the extent legislation is enacted that regulates greenhouse gas emissions, it could significantly increase our costs to (i) acquire allowances; (ii) operate and maintain our facilities; (iii) install new emission controls; and (iv) manage a greenhouse gas emissions program. If such legislation becomes law in the United States or any states we have operations and we are unable to pass these costs through as part of our services, it could have an adverse affect on our business and cash available for distributions.

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Item 6. ***Exhibits***

Exhibits

Exhibit Number	Description
3.1 *	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP (attached as Exhibit 3.4 to DCP Midstream Partners, LP's Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.2 *	First Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC (attached as Exhibit 3.6 to DCP Midstream Partners, LP's Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.3 *	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.4 *	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated as of January 20, 2009 and Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.5 *	Amendment No. 2 to the Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
3.6 *	Partnership Agreement Amendment, dated April 1, 2009, entered into by DCP Midstream GP, LP (attached as Exhibit 3.1 to DCP Midstream Partners LP's Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009)
10.1 *	Omnibus Agreement, dated December 7, 2005, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.4 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.2 *	DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.2 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.3 *	Contribution, Conveyance and Assumption Agreement, dated December 7, 2005, among DCP Midstream Partners, LP, DCP Midstream Operating LP, DCP Midstream GP, LLC, DCP Midstream GP, LP, Duke Energy Field Services, LLC, DEFS Holding 1, LLC, DEFS Holding, LLC, DCP Assets Holdings, LP, DCP Assets Holdings, GP, LLC, Duke Energy Guadalupe Pipeline Holdings, Inc., Duke Energy NGL Services, LP, DCP LP Holdings, LP and DCP Black Lake Holdings, LLC (attached as Exhibit 10.3 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.4 *	Natural Gas Gathering Agreement, dated June 1, 1987, as amended, between DEFS Assets Holding, LP, successor to the interest of Cornerstone Natural Gas Company and ConocoPhillips, successor to the interest of Phillips Petroleum Company (attached as Exhibit 10.5 to DCP Midstream Partners, LP's Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
10.5 *	First Amendment to Omnibus Agreement, dated April 1, 2006, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.6 to DCP Midstream Partners, LP's Form 10-Q (File No. 001-32678) filed with the SEC on August 11, 2006).
10.6 *	Contribution Agreement, dated October 9, 2006, between DCP LP Holdings, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on October 13, 2006).
10.7 *	Second Amendment to Omnibus Agreement, dated November 1, 2006, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.2 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
10.8 *	Purchase and Sale Agreement, dated March 7, 2007, between Anadarko Gathering Company, Anadarko Energy Services Company and DCP Midstream Partners, LP (attached as Exhibit 99.1 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).

10.9 *	Bridge Credit Agreement, dated May 9, 2007 among DCP Midstream Operating, LP, DCP Midstream Partners, LP, Wachovia Bank, National Association and Wachovia Capital Markets, LLC (attached as Exhibit 99.2 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.10 *	Third Amendment to Omnibus Agreement, dated May 9, 2007, among DCP Midstream, LLC (f/k/a Duke Energy Field Services, LLC), DCP Midstream GP, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, and DCP Midstream Operating, LP (attached as Exhibit 99.3 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.11 *	First Amendment to Credit Agreement, dated May 9, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association (attached as Exhibit 99.4 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.12 *	Contribution and Sale Agreement, dated May 21, 2007, between Gas Supply Resources Holdings, Inc., DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.13 *	Common Unit Purchase Agreement, dated May 21, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.14 *	Contribution Agreement, dated May 23, 2007, among DCP LP Holdings, LP, DCP Midstream, LLC, DCP Midstream GP, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.15 *	Common Unit Purchase Agreement, dated June 19, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).
10.16 *	Registration Rights Agreement, dated June 22, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).
10.17 *	Amended and Restated Credit Agreement, dated June 21, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association as Administrative Agent (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 27, 2007).
10.18 *	Fourth Amendment to Omnibus Agreement, dated July 1, 2007, by and among DCP Midstream, LLC f/k/a/ Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).
10.19 *	Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated July 1, 2007, between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.3 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).
10.20 *	Fifth Amendment to Omnibus Agreement dated August 7, 2007, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Form 10-Q (File No. 001-32678) filed with the SEC on August 9, 2007).
10.21 *	Sixth Amendment to Omnibus Agreement, dated August 29, 2007, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).
10.22 *	Registration Rights Agreement, dated August 29, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).
10.23 *	Agreement of Purchase and Sale dated October 1, 2008, by and among Ganesh Energy, LLC, Gas Processing & Pipeline, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on October 7, 2008).
10.24 *	Seventh Amendment to Omnibus Agreement, dated October 1, 2008, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC and DCP Midstream Operating , LP (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on October 7, 2008).
10.25 *	Contribution Agreement dated February 24, 2009, among DCP LP Holdings, LLC, DCP Midstream GP, LP DCP Midstream, LLC, and DCP Midstream Partners, LP (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).
10.26 *	Second Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated April 1, 2009 between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.2 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).

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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.
99.1	Condensed Consolidated Balance Sheet of DCP Midstream GP, LP as of June 30, 2009.
99.2	Condensed Consolidated Balance Sheet of DCP Midstream, LLC as of June 30, 2009.

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

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 August 10, 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)

EXHIBIT INDEX

Exhibit Number	Description
3.1 *	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP (attached as Exhibit 3.4 to DCP Midstream Partners, LP's Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.2 *	First Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC (attached as Exhibit 3.6 to DCP Midstream Partners, LP's Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.3 *	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.4 *	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated as of January 20, 2009 and Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.5 *	Amendment No. 2 to the Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
3.6 *	Partnership Agreement Amendment, dated April 1, 2009, entered into by DCP Midstream GP, LP (attached as Exhibit 3.1 to DCP Midstream Partners LP's Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009)
10.1 *	Omnibus Agreement, dated December 7, 2005, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.4 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.2 *	DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.2 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.3 *	Contribution, Conveyance and Assumption Agreement, dated December 7, 2005, among DCP Midstream Partners, LP, DCP Midstream Operating LP, DCP Midstream GP, LLC, DCP Midstream GP, LP, Duke Energy Field Services, LLC, DEFS Holding 1, LLC, DEFS Holding, LLC, DCP Assets Holdings, LP, DCP Assets Holdings, GP, LLC, Duke Energy Guadalupe Pipeline Holdings, Inc., Duke Energy NGL Services, LP, DCP LP Holdings, LP and DCP Black Lake Holdings, LLC (attached as Exhibit 10.3 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.4 *	Natural Gas Gathering Agreement, dated June 1, 1987, as amended, between DEFS Assets Holding, LP, successor to the interest of Cornerstone Natural Gas Company and ConocoPhillips, successor to the interest of Phillips Petroleum Company (attached as Exhibit 10.5 to DCP Midstream Partners, LP's Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
10.5 *	First Amendment to Omnibus Agreement, dated April 1, 2006, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.6 to DCP Midstream Partners, LP's Form 10-Q (File No. 001-32678) filed with the SEC on August 11, 2006).
10.6 *	Contribution Agreement, dated October 9, 2006, between DCP LP Holdings, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on October 13, 2006).
10.7 *	Second Amendment to Omnibus Agreement, dated November 1, 2006, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.2 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
10.8 *	Purchase and Sale Agreement, dated March 7, 2007, between Anadarko Gathering Company, Anadarko Energy Services Company and DCP Midstream Partners, LP (attached as Exhibit 99.1 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.9 *	Bridge Credit Agreement, dated May 9, 2007 among DCP Midstream Operating, LP, DCP Midstream Partners, LP, Wachovia Bank, National Association and Wachovia Capital Markets, LLC (attached as Exhibit 99.2 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).

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10.10 *	Third Amendment to Omnibus Agreement, dated May 9, 2007, among DCP Midstream, LLC (f/k/a Duke Energy Field Services, LLC), DCP Midstream GP, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, and DCP Midstream Operating, LP (attached as Exhibit 99.3 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.11 *	First Amendment to Credit Agreement, dated May 9, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association (attached as Exhibit 99.4 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.12 *	Contribution and Sale Agreement, dated May 21, 2007, between Gas Supply Resources Holdings, Inc., DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.13 *	Common Unit Purchase Agreement, dated May 21, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.14 *	Contribution Agreement, dated May 23, 2007, among DCP LP Holdings, LP, DCP Midstream, LLC, DCP Midstream GP, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.15 *	Common Unit Purchase Agreement, dated June 19, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).
10.16 *	Registration Rights Agreement, dated June 22, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).
10.17 *	Amended and Restated Credit Agreement, dated June 21, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association as Administrative Agent (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 27, 2007).
10.18 *	Fourth Amendment to Omnibus Agreement, dated July 1, 2007, by and among DCP Midstream, LLC f/k/a/ Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).
10.19 *	Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated July 1, 2007, between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.3 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).
10.20 *	Fifth Amendment to Omnibus Agreement dated August 7, 2007, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Form 10-Q (File No. 001-32678) filed with the SEC on August 9, 2007).
10.21 *	Sixth Amendment to Omnibus Agreement, dated August 29, 2007, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).
10.22 *	Registration Rights Agreement, dated August 29, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).
10.23 *	Agreement of Purchase and Sale dated October 1, 2008, by and among Ganesh Energy, LLC, Gas Processing & Pipeline, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on October 7, 2008).
10.24 *	Seventh Amendment to Omnibus Agreement, dated October 1, 2008, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC and DCP Midstream Operating , LP (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on October 7, 2008).
10.25 *	Contribution Agreement dated February 24, 2009, among DCP LP Holdings, LLC, DCP Midstream GP, LP DCP Midstream, LLC, and DCP Midstream Partners, LP (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).

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10.26 *	Second Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated April 1, 2009 between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.2 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 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.
99.1	Condensed Consolidated Balance Sheet of DCP Midstream GP, LP as of June 30, 2009.
99.2	Condensed Consolidated Balance Sheet of DCP Midstream, LLC as of June 30, 2009.

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

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Mark A. Borer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the six months ended June 30, 2009;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financials statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 10, 2009

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Angela A. Minas, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the six months ended June 30, 2009;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financials statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 10, 2009

/s/ Angela A. Minas

Angela A. Minas
Chief Financial Officer

Exhibit 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 (18 U.S.C. Section 1350)

The undersigned, the Chief Executive Officer of DCP Midstream GP, LLC, a Delaware limited liability company and general partner of DCP Midstream GP, LP, general partner of DCP Midstream Partners, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the six months ended June 30, 2009, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer
August 10, 2009

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

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 (18 U.S.C. Section 1350)

The undersigned, the Chief Financial Officer of DCP Midstream GP, LLC, a Delaware limited liability company and general partner of DCP Midstream GP, LP, general partner of DCP Midstream Partners, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the six months ended June 30, 2009, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Angela A. Minas
Angela A. Minas
Chief Financial Officer
August 10, 2009

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

DCP Midstream GP, LP

(A Delaware Limited Partnership)

Unaudited Condensed Consolidated Balance Sheet

As of June 30, 2009

**UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEET OF
DCP MIDSTREAM GP, LP**

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DCP MIDSTREAM GP, LP
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEET

	June 30, 2009 (Millions)
ASSETS	
Current assets:	
Cash and cash equivalents	$ 4.6
Accounts receivable:	
Trade, net of allowance for doubtful accounts of $0.8 million	35.2
Affiliates	57.6
Inventories	16.9
Unrealized gains on derivative instruments	5.9
Other	1.7
Total current assets	121.9
Restricted investments	35.1
Property, plant and equipment, net	973.9
Goodwill	89.1
Intangible assets, net	46.0
Equity method investments	117.0
Unrealized gains on derivative instruments	3.8
Other long-term assets	4.6
Total assets	$1,391.4
LIABILITIES AND EQUITY	
Current liabilities:	
Accounts payable:	
Trade	$ 57.3
Affiliates	13.4
Unrealized losses on derivative instruments	25.7
Accrued interest payable	0.8
Other	33.3
Total current liabilities	130.5
Long-term debt	638.0
Unrealized losses on derivative instruments	43.6
Other long-term liabilities	13.8
Total liabilities	825.9
Commitments and contingent liabilities	
Equity:	
Partners' equity	183.9
Note receivable from DCP Midstream, LLC	(183.0)
Accumulated other comprehensive loss	(0.6)
Total partners' equity	0.3
Noncontrolling interests	565.2
Total equity	565.5
Total liabilities and equity	$1,391.4

See accompanying notes to condensed consolidated balance sheet.

DCP MIDSTREAM GP, LP
NOTES TO UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEET
AS OF JUNE 30, 2009

1. Description of Business and Basis of Presentation

DCP Midstream GP, LP, with its consolidated subsidiaries, or us, we or our, is a Delaware limited partnership, whose interests are owned by DCP Midstream, LLC and DCP Midstream GP, LLC. We own approximately a 1% general partner interest and a 1% limited partner interest in and act as the general partner for DCP Midstream Partners, LP, or DCP Partners or the partnership, a master limited partnership formed in August 2005, which 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 natural gas liquids, or NGLs, and condensate. DCP Partners' operations and activities are managed by us. We, in turn, are managed by our general partner, DCP Midstream GP, LLC, which we refer to as our General Partner, which is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC directs DCP Partners' business operations through their ownership and control of our General Partner. DCP Midstream, LLC and its affiliates' employees provide administrative support to DCP Partners and operate our assets. DCP Midstream, LLC is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips.

The partnership includes: our Northern Louisiana system; our Southern Oklahoma system; our limited liability company interest in Discovery Producer Services LLC, or Discovery; our Wyoming system and a 70% interest in our Colorado system; our 50.1% interest in our East Texas system; our Michigan systems; our wholesale propane logistics business; and our NGL transportation pipelines.

In April 2009, DCP Partners acquired an additional 25.1% interest in DCP East Texas Holdings, LLC, or East Texas, and a fixed price natural gas liquids derivative by NGL component for the period of April 2009 to March 2010, or NGL Hedge, from DCP Midstream, LLC, in a transaction among entities under common control. Our East Texas system includes a natural gas processing complex with a total capacity of 780 MMcf/d and a NGL fractionator, which serves as the processing facility for our 900-mile gathering system, as well as third party gathering systems. The complex is adjacent to our Carthage Hub, which delivers gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 billion cubic feet per day, acts as a key exchange point for the purchase and sale of residue gas. Transfers of net assets or exchanges of units between entities under common control are accounted for as if the transfer occurred at the beginning of the period. Prior to this transaction, DCP Partners owned a 25.0% limited liability company interest in East Texas, which was accounted for under the equity method of accounting. Subsequent to this transaction DCP Partners own a 50.1% interest in East Texas. Accordingly, following this transaction, East Texas is accounted for as a consolidated entity. Approximately 98% of the $18.3 million deficit purchase price under the historical basis of the net acquired assets and the $49.7 million of DCP Partners' Class D units issued as consideration for this transaction were recorded as an increase in noncontrolling interests.

The condensed consolidated balance sheet has been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The consolidated balance sheet includes the accounts of DCP Midstream GP, LP and DCP Partners. We consolidate DCP Partners as we act as the general partner and as the limited partners do not have substantive kick-out or participating rights. DCP Partners' investments in greater than 20% owned affiliates, which are not variable interest rights and where DCP Partners does not exercise control, are accounted for using the equity method. All significant intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations and other affiliates have been identified in the consolidated balance sheet as transactions between affiliates.

The unaudited condensed consolidated balance sheet reflects all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position for the interim period. Certain information and notes normally included have been condensed or omitted from this interim balance sheet. The unaudited condensed consolidated balance sheet should be read in conjunction with the consolidated balance sheet and notes thereto as of December 31, 2008 included as Exhibit 99.1 to DCP Partners' Form 10-K filed with the Securities and Exchange Commission, or SEC, on March 5, 2009.

2. Summary of Significant Accounting Policies

Accounting for Sales of Units by a Subsidiary — Prior to our adoption of SFAS No.160 *'Noncontrolling Interests in Consolidated Financial Statements, an Amendment of Accounting Research Bulletin No. 51,'* or SFAS 160, on January 1, 2009, we accounted for sales of units by a subsidiary by recording a gain or loss on the sale of common equity of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the units sold. Effective upon the adoption of SFAS No. 160, the sale of units by a subsidiary are required to be accounted for as equity transactions. As a result of the adoption of SFAS No.160 a $5.4 million deferred gain on the sale of common units in DCP Partners was reclassified from other long-term liabilities to partners' equity in the condensed consolidated balance sheet.

3. Recent Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or SFAS, No. 168 "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a Replacement of FASB Statement No. 162," **or SFAS 168** — In June 2009, the FASB issued SFAS 168, which establishes the FASB Accounting Standards Codification, or the Codification, as the source of authoritative U.S. Generally Accepted Accounting Principles, or GAAP. The Codification supersedes all existing non-SEC accounting and reporting standards. This SFAS becomes effective for us for annual and interim periods beginning after September 15, 2009 and will not affect our condensed consolidated financial position as a result of adoption.

SFAS No. 167 "Amendments to FASB Interpretation No. 46(R)," **or SFAS 167** — In June 2009, the FASB issued SFAS 167, which requires entities to perform additional analysis of their variable interest entities and consolidation methods. This SFAS becomes effective for us on January 1, 2010 and we are in the process of assessing the impact of this guidance on our condensed consolidated financial position.

SFAS No. 165 "Subsequent Events," **or SFAS 165** — In May 2009, the FASB issued SFAS 165, which sets forth the recognition and disclosure requirements for events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. We adopted SFAS 165 effective June 30, 2009, and there was no effect on our condensed consolidated financial position as a result of adoption. All appropriate disclosure of subsequent events is made within the footnotes.

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 condensed consolidated 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 the deferred gain of approximately $5.4 million, relating to the sale of units by a subsidiary from long-term liabilities to partners' equity in the condensed consolidated balance sheet. We have reclassified our noncontrolling interest on our condensed consolidated balance sheets, from a component of liabilities to a component of 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 for all financial assets and liabilities. 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 condensed consolidated 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 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. Certain of the markets in which we transact have seen a decrease in overall volume; however, we believe that these markets continue to provide sufficient liquidity such that transactions are executed in an orderly manner at fair value. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated financial position.

***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 six months 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 are subject to the revised disclosure provisions of this FSP. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated financial position.

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. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated 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.

4. Acquisitions

Gathering and Compression Assets

On April 1, 2009, DCP Partners acquired an additional 25.1% interest in East Texas and the NGL Hedge from DCP Midstream, LLC, for aggregate consideration of 3,500,000 Class D units valued at $49.7 million.

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for certain costs incurred and centralized corporate functions performed by DCP Midstream, LLC on our behalf. Under the Omnibus Agreement, DCP Midstream, LLC has issued parental guarantees, totaling $43.0 million at June 30, 2009, to certain counterparties to our commodity derivative instruments.

Other Agreements and Transactions with DCP Midstream, LLC

In conjunction with DCP Partners acquisition of an additional 25.1% limited liability company interest in East Texas from DCP Midstream, LLC in April 2009, DCP Partners entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for certain East Texas capital projects as defined in the Contribution Agreement from April 1, 2009 for a period not to exceed three years. DCP Midstream, LLC made additional capital contributions of $11.5 million during the three months ended June 30, 2009 to East Texas for these capital projects.

On February 11, 2009, we announced that our East Texas natural gas processing complex and natural gas delivery system known as the Carthage Hub, had been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. DCP Partners is actively pursuing full reimbursement of costs and lost margin associated with the incident from the responsible third party. We also have insurance covering these amounts, net of applicable deductibles. Following this incident, DCP Midstream, LLC has agreed to reimburse us 25% of any claims received as reimbursement of costs and lost margin associated with the incident, from the responsible third party. DCP Midstream, LLC will pay 75% of costs related to the incident.

On February 25, 2009, DCP Partners entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC will contribute an additional 25.1% interest in East Texas to DCP Partners in exchange for 3,500,000 DCP Partners Class D units, providing DCP Partners with a 50.1% interest in East Texas. This transaction closed in April 2009. Accordingly, following this transaction, East Texas is accounted for as a consolidated entity.

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.

- 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.

In conjunction with DCP Partners acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, DCP Partners entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to DCP Partners as reimbursement for certain Discovery capital projects, which were forecasted to be completed prior to DCP Partners acquisition of a 40% limited liability company interest in Discovery. DCP Midstream, LLC made capital contributions to DCP Partners during the six months ended June 30, 2009 of $0.7 million to reimburse DCP Partners for these capital projects.

In conjunction with our acquisition of East Texas and Discovery in July 2007 DCP Partners entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for 25% of certain East Texas capital expenditures, defined in the agreement, from July 1, 2007, through completion of the capital projects for a period not to exceed three years. DCP Midstream, LLC made additional capital contributions to East Texas for these capital projects of $6.2 million during the six months ended June 30, 2009.

DCP Midstream, LLC has issued additional parental guarantees outside of the Omnibus Agreement totaling $40.0 million at June 30, 2009, to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties.

We have a note receivable from DCP Midstream, LLC totaling $183.0 million. This note is due on demand; however, we do not anticipate requiring DCP Midstream, LLC to repay this amount. Accordingly we have reflected this receivable as a component of partners' deficit. The note receivable bears interest at the greater of 5.00% or the applicable federal rate in effect under section 1274(d) of the Internal Revenue Code of 1986. The interest rate in effect on the note was 5.00% at June 30, 2009. All interest income earned under the note has been distributed to DCP Midstream, LLC.

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 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 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 $0.7 million of capital reimbursements during the six months ended June 30, 2009.

We had balances with affiliates as follows:

	June 30, 2009 (Millions)
DCP Midstream, LLC:	
Accounts receivable	$ 55.0
Accounts payable	$ 11.6
Unrealized gains on derivative instruments—current	$ 1.0
Unrealized losses on derivative instruments—current	$ (1.0)
Spectra Energy:	
Accounts receivable	$ 1.2
Accounts payable	$ 1.3
ConocoPhillips:	
Accounts receivable	$ 1.4
Accounts payable	$ 0.5

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	Depreciable Life	June 30, 2009 (Millions)
Gathering systems	15 — 30 Years	$ 576.5
Processing plants	25 — 30 Years	407.6
Terminals	25 — 30 Years	28.9
Transportation	25 — 30 Years	217.5
Underground storage	20 — 50 Years	0.1
General plant	3 — 5 Years	15.0
Construction work in progress		89.1
Property, plant and equipment		1,334.7
Accumulated depreciation		(360.8)
Property, plant and equipment, net		$ 973.9

The above amount includes accrued capital expenditures of $18.7 million as of June 30, 2009, which is included in other current liabilities in the condensed consolidated balance sheet.

7. Equity Method Investments

The following table summarizes our equity method investments:

	Percentage of Ownership as of June 30, 2009	Carrying Value as of June 30, 2009
		(Millions)
Discovery Producer Services LLC	40%	$ 110.3
Black Lake Pipe Line Company	45%	6.5
Other	50%	0.2
Total equity method investments		$ 117.0

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $38.5 million at June 30, 2009, 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 $5.9 million at June 30, 2009, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

In the second quarter of 2009, Discovery's LLC agreement was amended to calculate available cash based on cash on hand at the end of the month preceding the end of each calendar quarter (e.g. May 31 for the second quarter) and to require distribution of available cash by the end of each calendar quarter. Prior to this amendment, Discovery calculated available cash based on cash on hand at the end of each calendar quarter and made the related distribution within 30 days of the end of each calendar quarter.

The following summarizes balance sheet information of our equity method investments:

	June 30, 2009
	(Millions)
Current assets	$ 66.5
Long-term assets	389.5
Current liabilities	(40.1)
Long-term liabilities	(22.1)
Net assets	$ 393.8

8. 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.

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 relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

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

Interest Rate Derivative Assets and Liabilities

We have interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt. 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 and entity valuation adjustments 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 June 30, 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.

The following table presents the financial instruments carried at fair value as of June 30, 2009, by condensed consolidated balance sheet caption and by valuation hierarchy, as described above:

	Quoted Market Prices In Active Markets (Level 1)	Internal Models With Significant Observable Market Inputs (Level 2)	Internal Models With Significant Unobservable Market Inputs (Level 3)	Total Carrying Value
		(Millions)		
Current assets:				
Commodity derivatives (a)	$ —	$ 4.7	$ 1.2	$ 5.9
Long-term assets:				
Restricted investments	$ —	$ 35.1	$ —	$ 35.1
Commodity derivatives (b)	$ —	$ 2.9	$ —	$ 2.9
Interest rate derivatives (b)	$ —	$ 0.9	$ —	$ 0.9
Current liabilities (c):				
Commodity derivatives	$ —	$ (6.9)	$ (0.1)	$ (7.0)
Interest rate derivatives	$ —	$ (18.7)	$ —	$ (18.7)
Long-term liabilities (d):				
Commodity derivatives	$ —	$ (29.9)	$ (0.9)	$ (30.8)
Interest rate derivatives	$ —	$ (12.8)	$ —	$ (12.8)

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

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

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

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

Changes in Level 3 Fair Value Measurements

The table below illustrates a rollforward of the amounts included in our condensed consolidated balance sheet 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.

	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 June 30, 2009
			(Millions)		
Commodity derivative instruments:					
Current assets	$ 0.3	$ (2.7)	$ —	$ 3.6	$ 1.2
Long-term assets	$ 1.7	$ (1.7)	$ —	$ —	$ —
Current liabilities	$ —	$ (0.1)	$ —	$ —	$ (0.1)
Long-term liabilities	$ —	$ (0.9)	$ —	$ —	$ (0.9)

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

9. Debt

Long-term debt was as follows:

	June 30, 2009
	(Millions)
Revolving credit facility, weighted-average interest rate of 1.03%, due June 21, 2012 (a)	$ 603.0
Term loan facility, interest rate of 0.42%, due June 21, 2012	35.0
Total long-term debt (b)	$ 638.0

(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 4.47% on the $603.0 million of outstanding debt under our revolving credit facility as of June 30, 2009.

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

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 $789.6 million revolving credit facility; and
- a $35.0 million term loan facility.

The above amounts are net of non-participation by Lehman Brothers Commercial Bank. At June 30, 2009 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 June 30, 2009 the available capacity under the revolving credit facility was $188.5 million.

Other Agreements

As of June 30, 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.

10. 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 contract type. 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 primarily utilize crude oil swaps and following DCP Partners acquisition of the NGL Hedge on April 1, 2009, NGL derivatives to mitigate a significant portion of our commodity price exposure for propane and heavier NGLs. Historically, there has been a relationship 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 a portion of NGL price risks. 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 relationship. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2014 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 in earnings.

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 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 in earnings.

Furthermore, with respect to our Pelico system, we may enter into financial derivatives to lock in price differentials across the system and connected storage 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 in the current period in earnings.

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 earnings. 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 earnings 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 earnings.

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.

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 effective event of default under 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. These provisions apply if we default in making timely payments under those agreements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our credit agreement. As of June 30, 2009, we are not a party to any agreements that would be subject to these provisions other than our credit agreement.

Our commodity derivative contracts that are not governed by ISDA contracts 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 June 30, 2009, we had approximately $36.7 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any 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 contracts permit 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 June 30, 2009 if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of June 30, 2009, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $28.9 million.

As of June 30, 2009 our interest rate swaps were in a net liability position of approximately $30.6 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 June 30, 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 June 30, 2009, we had no cash collateral posted with counterparties to our commodity derivative instruments.

Summarized Derivative Information

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

	June 30, 2009 (Millions)
Interest rate cash flow hedges:	
Net deferred losses in AOCI	$ (0.6)

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	June 30, 2009 (Millions)	Balance Sheet Line Item	June 30, 2009 (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	$ (18.7)
Unrealized gains on derivative instruments – long term	0.9	Unrealized losses on derivative instruments – long term	(12.8)
	$ 0.9		$ (31.5)
Derivative Assets Not Designated as Hedging Instruments:		**Derivative Liabilities Not Designated as Hedging Instruments:**	
Commodity derivatives:		**Commodity derivatives:**	
Unrealized gains on derivative instruments – current	$ 5.9	Unrealized losses on derivative instruments – current	$ (7.0)
Unrealized gains on derivative instruments – long term	2.9	Unrealized losses on derivative instruments – long term	(30.8)
	$ 8.8		$ (37.8)

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

	Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months (Millions)
Interest rate derivatives	$ (0.4)
Commodity derivatives	$ —

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.

	June 30, 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	(450,800)	(1,350,000)	(111,621)
2010	(950,225)	(2,023,500)	(74,001)
2011	(949,000)	(1,314,000)	—
2012	(777,750)	(1,317,600)	—
2013	(748,250)	(730,000)	—
2014	(365,000)	—	—

We periodically enter into interest rate swap agreements to mitigate our floating rate interest exposure. As of June 30, 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.

11. Non-Controlling Interest

Non-controlling interest represents (1) the ownership interests of DCP Partners' public unitholders in net assets of DCP Partners through DCP Partners' publicly traded common units; (2) affiliate ownership interests in common units and Class D units; (3) the non-controlling interest holders' portion of the net assets of our Collbran Valley Gas Gathering system joint venture, acquired with the MEG acquisition in August 2007; (4) the non-controlling interest holders' portion of the net assets of Jackson Pipeline Company, a partnership we acquired with the MPP acquisition in October 2008; and (5) the noncontrolling interest holders' portion in the net assets of East Texas.

We own approximately a 1% general partner interest and a 1% limited partner interest in DCP Partners. For financial reporting purposes, the assets and liabilities of DCP Partners are consolidated with those of our own, with any third party and affiliate investors' interest in our condensed consolidated balance sheet amounts shown as non-controlling interest. Distributions to and contributions from non-controlling interests represent cash payments and cash contributions, respectively, from such third-party and affiliate investors.

At June 30, 2009, DCP Partners had outstanding 28,233,183 common units and 3,500,000 Class D units.

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

In April 2009, DCP Partners issued 3,500,000 Class D units valued at $49.7 million. The Class D units were issued to DCP LP Holdings, LP and DCP Midstream GP, LP in consideration for an additional 25.1% interest in East Texas and the NGL Hedge. The Class D units represent limited partnership interests in the partnership.

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 us as the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to the unitholders and to us as the general partner for any one or more of the next four quarters;

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

General Partner Interest and Incentive Distribution Rights — Prior to June 2007, as the general partner, we were entitled to 2% of all quarterly distributions that we make prior to DCP Partners' liquidation. We have the right, but not the obligation, to contribute a proportionate amount of capital to maintain our current general partner interest. We did not participate in certain issuances of common units by DCP Partners during 2007 and 2008. Therefore, our 2% interest in these distributions was reduced to approximately 1%.

The incentive distribution rights held by us as the general partner entitle us to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Currently, our distribution related to our incentive distribution rights is at the highest level. Our incentive distribution rights were not reduced as a result of these private placement agreements, and will not be reduced if DCP Partners issues additional units in the future and we do not contribute a proportionate amount of capital to DCP Partners to maintain our 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 our incentive distribution rights.

Class D Units — The Class D Units will be eligible to receive distributions of Available Cash in August 2009, including the payment of the second quarter distribution. The Class D Units otherwise generally have the same rights as the Partnership's outstanding Common Units and will convert into the Partnership's Common Units on a one-for-one basis on August 17, 2009.

Subordinated Units — All of the 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 the partnership agreement. DCP Partners' board of directors certified that all conditions for early conversion were satisfied.

Distributions of Available Cash after the Subordination Period — DCP Partners' partnership agreement, after adjustment for our relative ownership level, requires that DCP Partners 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 us as 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 us as the general partner, plus our 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 us as the general partner, plus our 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 us as the general partner, plus our pro rata interest, and the remainder to all unitholders.

The following table presents DCP Partners' cash distributions paid in 2009:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
May 15, 2009	$ 0.600	$ 20.1
February 13, 2009	0.600	20.1

12. Partners' Equity

At June 30, 2009, partners' equity consisted of our capital account, AOCI and a note receivable from DCP Midstream, LLC.

As of June 30, 2009, we had a balance of $0.3 million in our partners' equity account.

13. 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 condensed consolidated financial position.

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. We have negotiated a resolution of this matter with the CDPHE for approximately $186,000, which will consist of a monetary penalty and an agreement to perform a supplemental environmental project.

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., or El Paso, 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. During the second quarter of 2009 we filed an appeal in the 14th Court of Appeals, Texas and will continue to defend ourselves vigorously against this claim. El Paso has filed an additional lawsuit in Louisiana, claiming damages for the same claims as the Texas matter, but for periods prior to our ownership of the asset. We intend to file motions to remove us from the Louisiana matter. As a result of the jury verdict, we recorded a contingent liability of $2.5 million in the fourth quarter of 2008 for this matter, which is included in other long-term liabilities in the condensed consolidated balance sheet as of June 30, 2009.

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.

Insurance — We renewed our insurance policies in June and July 2009 for the 2009-2010 insurance year. Previously, we carried insurance jointly with DCP Midstream, LLC. Following our 2009 renewals, we now contract with a third party insurer separately from DCP Midstream for: (1) statutory workers' compensation insurance; (2) automobile liability insurance for all owned, non-owned and hired vehicles; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) property insurance, which covers replacement value of all real and personal property and includes business interruption/extra expense. However, we are still jointly insured with DCP Midstream, LLC for directors and officers insurance covering our directors and officers for acts related to our business activities. As a result of separating this insurance, we have reduced the excess liability and property limits to match the type and size of assets covered by this insurance. These changes have not resulted in any material change to the premiums we will pay in the 2009-2010 insurance year. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies that are of similar size to us and with similar types of operations.

Discovery's previous property insurance policy expired in June 2009. Our insurance on Discovery for the 2009-2010 insurance year covers onshore and offshore property, onshore named windstorm and onshore business interruption insurance. The availability of named windstorm insurance has been significantly reduced as a result of higher industry-wide damage claims in past years. Additionally, the named windstorm insurance that is available comes at significantly higher premium amounts, higher deductibles and lower coverage limits. Consequently, Discovery elected to not purchase offshore named windstorm insurance coverage for the 2009-2010 insurance year.

14. 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) the Northern Louisiana system; (2) the Southern Oklahoma system; (3) our 40% limited liability company interest in Discovery; (4) our Colorado and Wyoming systems; (5) our East Texas system; and (6) 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 the 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.

The following table sets forth our segment information:

	June 30, 2009 (Millions)
Segment long-term assets:	
Natural Gas Services	$1,141.9
Wholesale Propane Logistics	54.0
NGL Logistics	33.3
Other (a)	40.3
Total long-term assets	1,269.5
Current assets	121.9
Total assets	$1,391.4

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

15. Subsequent Events

We have evaluated subsequent events occurring through August 10, 2009, the date the financial statements were issued.

On July 28, 2009, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on August 14, 2009 to unitholders of record on August 7, 2009.

Exhibit 99.2

DCP Midstream, LLC
Unaudited Condensed Consolidated Balance Sheet
As of June 30, 2009

DCP MIDSTREAM, LLC
CONDENSED CONSOLIDATED BALANCE SHEET
(Unaudited)
(millions)

	June 30, 2009
ASSETS	
Current assets:	
Cash and cash equivalents	$ 101
Accounts receivable:	
Customers, net of allowance for doubtful accounts of $7 million	632
Affiliates	177
Other	46
Inventories	62
Unrealized gains on derivative instruments	188
Other	21
Total current assets	1,227
Property, plant and equipment, net	4,956
Restricted investments	35
Investments in unconsolidated affiliates	178
Intangible assets, net	308
Goodwill	566
Unrealized gains on derivative instruments	85
Other long-term assets	68
Total assets	$ 7,423
LIABILITIES AND MEMBERS' EQUITY	
Current liabilities:	
Accounts payable:	
Trade	$ 707
Affiliates	53
Other	29
Short-term borrowings	2
Distributions payable to members	18
Unrealized losses on derivative instruments	232
Accrued interest payable	72
Accrued taxes	33
Other	152
Total current liabilities	1,298
Long-term debt	3,666
Unrealized losses on derivative instruments	76
Other long-term liabilities	118
Commitments and contingent liabilities	
Members' equity:	
Members' interest	1,919
Retained earnings	80
Accumulated other comprehensive loss	(15)
Total members' equity	1,984
Noncontrolling interest	281
Total equity	2,265
Total liabilities and members' equity	$ 7,423

See Notes to Condensed Consolidated Balance Sheet

DCP MIDSTREAM, LLC
NOTES TO CONDENSED CONSOLIDATED BALANCE SHEET
(Unaudited)

1. General and Summary of Significant Accounting Policies

Basis of Presentation — DCP Midstream, LLC, with its consolidated subsidiaries, us, we, our, or the Company, is a joint venture owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. We operate in the midstream natural gas industry. Our primary operations consist of gathering, processing, compressing, transporting and storing of natural gas, and fractionating, transporting, gathering, treating, processing and storing of natural gas liquids, or NGLs, as well as marketing, from which we generate revenues primarily by trading and marketing natural gas and NGLs.

DCP Midstream Partners, LP, or DCP Partners, is a master limited partnership, of which our subsidiary, DCP Midstream GP, LP, acts as general partner. At June 30, 2009, we owned an approximately 37% limited partnership interest and an approximately 1% general partnership interest in DCP Partners as well as incentive distribution rights that entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved. As the general partner of DCP Partners, we have responsibility for its operations. We exercise control over DCP Partners and we account for them as a consolidated subsidiary.

We are governed by a five member board of directors, consisting of two voting members from each parent and our Chief Executive Officer and President, a non-voting member. All decisions requiring board of directors' approval are made by simple majority vote of the board, but must include at least one vote from both a Spectra Energy and ConocoPhillips board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Spectra Energy and ConocoPhillips.

The condensed consolidated balance sheet reflects 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 balance sheet has been condensed in or omitted from this interim balance sheet. The condensed consolidated balance sheet should be read in conjunction with our consolidated balance sheet and notes thereto for the year ended December 31, 2008.

The condensed consolidated balance sheet includes the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control, variable interest entities where we are the primary beneficiary, and undivided interests in jointly owned assets. We also consolidate DCP Partners, which we control as the general partner and where the limited partners do not have substantive kick-out or participating rights. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method. Intercompany balances and transactions have been eliminated.

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

Distributions — Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or the LLC Agreement, we are required to make quarterly distributions to Spectra Energy and ConocoPhillips based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code Section 704(c). This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member with a minimum of each member's tax, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Spectra Energy and ConocoPhillips. No distributions were paid during the six months ended June 30, 2009.

Our board of directors determines the amount of the periodic dividends to be paid to Spectra Energy and ConocoPhillips, by considering net income attributable to members' interests, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. No dividends were paid during the six months ended June 30, 2009.

DCP Partners considers the payment of a quarterly distribution to the holders of its common, subordinated and Class D units, to the extent DCP Partners has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a wholly-owned subsidiary of ours. There is no guarantee, however, that DCP Partners will pay the minimum quarterly distribution on the units in any quarter. DCP Partners will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement. Our limited partner interest in DCP Partners consists of both common and Class D units, and included subordinated units until they were converted to common units in February 2009. The Class D units will be eligible to receive distributions in August 2009, including the payment of the second quarter distribution. The Class D units will convert to common units on a one for one basis on August 17, 2009. During the six months ended June 30, 2009, DCP Partners paid distributions of approximately $24 million to its public unitholders. In addition to our partnership interests we hold incentive distribution rights, which entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved.

Accounting for Sales of Units by a Subsidiary — We accounted for sales of units by a subsidiary by recording a deferred item on the sale of common equity of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the units sold. At the time that this equity was issued, DCP Partners had two classes of units outstanding, consisting of subordinated and limited partner units, which required us to record a deferred liability of approximately $270 million within our condensed consolidated balance sheet. During the first quarter of 2009 the subordination period ended and these units were converted into limited partner units and we reclassified these deferred liabilities from long-term liabilities to members' interest within our condensed consolidated balance sheet.

Recent Accounting Pronouncements — Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or SFAS, No. 168 "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles — a Replacement of FASB Statement No. 162," or SFAS 168 — In June 2009, the FASB issued SFAS 168, which establishes the FASB Accounting Standards Codification, or the Codification, as the source of authoritative US Generally Accepted Accounting Principles, or GAAP. The Codification supersedes all existing non-SEC accounting and reporting standards. This SFAS becomes effective for us for annual and interim periods beginning after September 15, 2009 and will not affect our condensed consolidated financial position as a result of adoption.

SFAS No. 167 "Amendments to FASB Interpretation No. 46(R)," **or SFAS 167** — In June 2009, the FASB issued SFAS 167, which requires entities to perform additional analysis of their variable interest entities and consolidation methods. This SFAS becomes effective for us on January 1, 2010 and we are in the process of assessing the impact of this guidance on our condensed consolidated financial position.

SFAS No. 165 "Subsequent Events," or SFAS 165 — In May 2009, the FASB issued SFAS 165, which sets forth the recognition and disclosure requirements for events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. We adopted SFAS 165 effective June 30, 2009, and there was no effect on our condensed consolidated financial position as a result of adoption. All appropriate disclosure of subsequent events is made within Footnote 11.

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. SFAS 161 impacts only disclosures so there was no effect on our condensed consolidated 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. As a result of adoption, we have reclassified approximately $270 million from long-term liabilities to members' interest within our condensed consolidated balance sheet

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 for all financial assets and liabilities. 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 condensed consolidated 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 sheet. Generally, costs to renew or extend such contracts are not significant, and are expensed 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. Certain of the markets in which we transact have seen a decrease in overall volume; however, we believe that these markets continue to provide sufficient liquidity such that transactions are executed in an orderly manner at fair value. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated financial position.

***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 six months ended June 30, 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 are subject to the revised disclosure provisions of this FSP. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated financial position.

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. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated 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 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.

2. Acquisitions and Dispositions

Acquisitions

Acquisition of Various Gathering, Pipeline and Compression Assets — On October 1, 2008, DCP Partners 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 since that date. Under the terms of the acquisition, DCP Partners paid a purchase price of $145 million, plus net working capital and other adjustments of approximately $3 million, subject to additional customary purchase price adjustments. DCP Partners may pay up to an additional $15 million to the sellers depending on the earnings of the assets after a three-year period. DCP Partners financed the acquisition by liquidating a portion of its restricted investments. In addition, DCP Partners entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay DCP Partners up to approximately $2 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments would reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of the Michigan assets are satisfied. Certain of these performance criteria were satisfied and as a result, the amount the seller will pay DCP Partners has been reduced to approximately $1 million per year as of June 30, 2009. DCP Partners initially held a $25 million letter of credit to secure the seller's contingent future 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 million as of June 30, 2009.

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 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 adjustments as additional information is obtained. The purchase price allocation is as follows:

	(millions)
Cash	$ 2
Accounts receivable	2
Property, plant and equipment	116
Goodwill	7
Intangible assets	19
Other long-term assets	4
Noncontrolling interest	(2)
Total purchase price allocation	$ 148

Contributions to DCP Partners

DCP East Texas Holdings, LLC — On April 1, 2009, we contributed an additional 25.1% interest in East Texas to DCP Partners in exchange for 3,500,000 DCP Partners Class D units. The Class D units will convert to common units and will be eligible to receive distributions in August 2009, including the payment of DCP Partners' second quarter distribution. We also provided a fixed price NGL derivative by NGL component for the period of April 2009 to March 2010. We 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.

3. Agreements and Transactions with Affiliates

ConocoPhillips

Long-term NGL Purchases Contract and Transactions — We sell a portion of our residue gas and NGLs to ConocoPhillips and its subsidiaries, including Chevron Phillips Chemical Company LLC, or CP Chem, a 50% equity investment of ConocoPhillips. In addition, we purchase natural gas from ConocoPhillips. Under the NGL Output Purchase and Sale Agreements, or the NGL Agreements, with ConocoPhillips and CP Chem, ConocoPhillips and CP Chem have the right to purchase at index-based prices substantially all NGLs produced by our various processing plants located in the Mid-Continent and Permian Basin regions, and the Austin Chalk area, which include approximately 40% of our total NGL production. The NGL Agreements also grant ConocoPhillips and CP Chem the right to purchase at index-based prices certain quantities of NGLs produced at processing plants that are acquired and/or constructed by us in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. The primary terms of the agreements are effective until January 1, 2015. We anticipate continuing to purchase and sell these commodities and provide these services to ConocoPhillips and CP Chem in the ordinary course of business.

Spectra Energy

Commodity Transactions — We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering, transportation and other services to Spectra Energy and their subsidiaries. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

Included in the condensed consolidated balance sheet in accounts receivable—affiliates as of June 30, 2009 are insurance recovery receivables of approximately $15 million.

Transactions with other unconsolidated affiliates

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 to, unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

4. Inventories

Inventories were as follows:

	June 30, 2009 (millions)
Natural gas held for resale	$ 9
NGLs	53
Total inventories	$ 62

5. 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.

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 exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil, or natural gas futures) or over the counter instruments, or OTC, instruments (such as natural gas contracts, crude oil or NGL swaps). The exchange traded instruments are generally executed on the NYMEX exchange with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk exposure. To mitigate a portion of this risk, and to manage commodity price risk related primarily, to owned natural gas storage and pipeline assets we engage in natural gas asset based trading and marketing, we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices 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 based upon observable data. In instances where we utilize an interpolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 2. In certain limited instances, we may extrapolate based upon the last readily observable data, developing our own expectation of fair value. To the extent that we have utilized extrapolated data, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which expose us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which may not be 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 relationship of NGL prices to crude oil, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

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

Interest Rate Derivative Assets and Liabilities

We have interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt or our fixed rate debt for floating rate debt. The swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar characteristics, 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 as Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit and our entity valuation adjustments 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 DCP Partners' 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. However, 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 June 30, 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 condensed 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.

The following table presents the financial instruments carried at fair value as of June 30, 2009:

Level 1: Quoted Market Prices in Active Markets

Level 2: Internal Models with Significant Observable Market Inputs

Level 3: Internal Models with Significant Unobservable Market Inputs

	Level 1	Level 2	Level 3	Total Carrying Value
Current assets:				
Commodity derivatives (a)	$ 40	$ 94	$ 54	$ 188
Available-for-sale securities (b)	$ —	$ —	$ —	$ —
Long-term assets:				
Commodity derivatives (c)	$ 56	$ 19	$ 9	$ 84
Interest rate derivatives (c)	$ —	$ 1	$ —	$ 1
Restricted investments	$ —	$ 35	$ —	$ 35
Current liabilities (d):				
Commodity derivatives	$ (46)	$ (94)	$ (73)	$ (213)
Interest rate derivatives	$ —	$ (19)	$ —	$ (19)
Long-term liabilities (e):				
Commodity derivatives	$ (7)	$ (34)	$ (22)	$ (63)
Interest rate derivatives	$ —	$ (13)	$ —	$ (13)

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

(b) Included in cash and cash equivalents in our condensed consolidated balance sheet.

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

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

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

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our condensed consolidated balance sheet 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.

	December 31, 2008	Net Realized and Unrealized Gains (Losses) Included in Earnings	Transfers In/Out of Level 3 (a)	Purchases, Issuances and Settlements, Net	June 30, 2009	Net Unrealized Gains (Losses) Still Held Included in Earnings (b)
				(millions)		
Commodity derivative instruments:						
Current assets	$ 210	$ (64)	$ (15)	$ (77)	$ 54	$ (29)
Long-term assets	$ 22	$ (13)	$ —	$ —	$ 9	$ (11)
Current liabilities	$ (155)	$ 31	$ 25	$ 26	$ (73)	$ (2)
Long-term liabilities	$ (44)	$ 22	$ —	$ —	$ (22)	$ 23

(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 trading and marketing gains or losses, attributable to the change in unrealized gains or losses relating to assets and liabilities classified as Level 3 that are still held at June 30, 2009.

Estimated Fair Value of Financial Instruments

The fair value of short-term investments, restricted investments, accounts receivable, accounts payable and short-term borrowings are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on mark-to-market and hedging instruments are carried at fair value.

The estimated fair values of current debt, including current maturities of long-term debt, and long-term debt, with the exception of DCP Partners' long-term debt, are determined by prices obtained from market quotes. The carrying value of DCP Partners' long-term debt approximates fair value, as the interest rate is variable and reflects current market conditions. The estimated fair value of long-term debt was $3,578 million as of June 30, 2009.

6. Financing

Long-term debt was as follows:

	June 30, 2009 (millions)
Debt securities:	
Issued August 2000, interest at 7.875% payable semiannually, due August 2010	$ 800
Issued January 2001, interest at 6.875% payable semiannually, due February 2011	250
Issued November 2008, interest at 9.700% payable semiannually, due December 2013	250
Issued October 2005, interest at 5.375% payable semiannually, due October 2015	200
Issued February 2009, interest at 9.750% payable semiannually, due March 2019	450
Issued August 2000, interest at 8.125% payable semiannually, due August 2030 (a)	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450
DCP Midstream's $450 million credit facility revolver, weighted-average interest rate of 0% and 2.69%, respectively, due April 2012	—
DCP Partners' credit facility revolver, weighted-average interest rate of 1.03% and 2.08%, respectively, due June 2012 (b)	603
DCP Partners' credit facility term loan, interest rate of 0.42% and 1.54%, respectively, due June 2012 (c)	35
Fair value adjustments related to interest rate swap fair value hedges (a)	41
Unamortized discount	(13)
Long-term debt	$ 3,666

(a) The swaps associated with this debt were terminated in December 2008. The remaining fair value adjustments of $41 million related to the swaps will be amortized as a reduction to interest expense through the maturity date of the debt.

(b) $575 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 4.47% on the $603 million of outstanding debt under the DCP Partners revolving credit facility as of June 30, 2009.

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

Debt Securities — In February 2009, we issued $450 million principal amount of 9.75% Senior Notes due 2019, or the 9.75% Notes, for proceeds of approximately $441 million, net of unamortized discounts and related offering costs. The 9.75% Notes mature and become due and payable on March 15, 2019. We will pay interest semiannually on March 15 and September 15 of each year, beginning September 15, 2009. The net proceeds from this offering were used for general corporate purposes, which included repayment of outstanding borrowings.

The debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. Interest is payable semiannually. The debt securities are unsecured and are redeemable at our option.

DCP Midstream's Credit Facilities with Financial Institutions — We have a $450 million revolving credit facility, or the Facility, which is used to support our commercial paper program, and for working capital and other general corporate purposes. The Facility may be used for letters of credit. Any outstanding borrowings under the Facility at maturity may, at our option, be converted into an unsecured one-year term loan. The available capacity under the Facility at June 30, 2009 was $445 million and there were no borrowings outstanding. There was no commercial paper outstanding as of June 30, 2009 and there were approximately $5 million in letters of credit outstanding.

In June 2009, we terminated our $350 million revolving credit facility agreement, or the $350 Million Facility, which would have matured in November 2009. The $350 Million Facility was used to support our commercial paper program, for working capital requirements and for other general corporate purposes. As of June 30, 2009, there were no borrowings under the $350 Million Facility and during the six months ended June 30, 2009, we expensed approximately $3 million of deferred financing costs relating to the early termination of this facility, which would have been amortized through the date of maturity in November 2009.

DCP Midstream Partners' Credit Facilities with Financial Institutions — DCP Partners has a 5-year credit agreement, or the DCP Partners' Credit Agreement, which matures on June 21, 2012 and consists of a $790 million revolving credit facility and a $35 million term loan facility at June 30, 2009. These amounts are net of $25 million non-participation by Lehman Brothers Commercial Bank, a lender to DCP Partners' Credit Agreement. At June 30, 2009, DCP Partners had less than $1 million of letters of credit outstanding under the DCP Partners' Credit Agreement. As of June 30, 2009, the available capacity under the revolving credit facility was $189 million and there were outstanding borrowings of $603 million. 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 sheet as of June 30, 2009.

Other Agreements — As of June 30, 2009, DCP Partners had an outstanding letter of credit with a counterparty to their commodity derivative instruments of $10 million, which reduces the amount of cash DCP Partners 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 the DCP Partners' Credit Agreement.

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

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. All of our derivative activities are conducted under the governance of an internal Risk Management Committee that establishes policies, limiting exposure to market risk and requiring daily reporting to management of potential financial exposure. These policies include statistical risk tolerance limits using historical price movements to calculate daily value at risk. The following briefly describes each of the risks that we manage.

Commodity Price Risk

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. The risks, strategies and instruments used to mitigate such risks, as well as the method of accounting are discussed and summarized in the tables below.

Natural Gas Asset Based Trading and Marketing

Our natural gas asset based trading and marketing activities engage in the business of trading energy related products and services, including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and we may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. We manage commodity price risk related to owned and leased natural gas storage and pipeline assets by engaging in natural gas asset based trading and marketing. The commercial activities related to our natural gas asset based trading and marketing primarily consist of time spreads and basis spreads.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. A time spread transaction is executed by establishing a long gas position at one point in time and establishing a corresponding short gas position at a future point in time. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in earnings. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in earnings. Even though we may have economically hedged our exposure and locked in a future margin the use of lower of cost or market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

We may execute basis spread transactions when the market price differential between locations on a pipeline asset exceeds our cost of transporting physical gas through our owned and/or leased pipeline asset. When this market condition exists, we may execute derivative instruments around this differential at the market price. This basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in earnings. As discussed above, the accounting for physical gas purchases and sales and the accounting for the derivative instruments used to manage such purchases and sales differ, and may subject our earnings to market volatility, even though the transaction represents an economic hedge in which we have locked in a future margin.

Additionally, in order for our storage facilities to remain operational, we maintain a minimum level of base gas in each storage cavern, which is capitalized on our condensed consolidated balance sheet as a component of property, plant and equipment, net. In the fourth quarter of 2008 we commenced a capacity expansion project for one of our storage caverns, which required us to sell all of the base gas within the cavern. We expect this project to be completed in early 2010 at which point we will be required to purchase a significant amount of base gas to restore our storage cavern to operation. To mitigate the risk associated with this forecasted purchase of natural gas, we executed a series of derivative financial instruments, which have been designated as cash flow hedges. Any changes in fair value of these derivative instruments will be deferred in accumulated other comprehensive income or loss, or AOCI, until the underlying purchase of inventory occurs. While the cash paid or received upon settlement of these hedges will economically offset the cash required to purchase the base gas, any deferred gain or loss at the time of the purchase in 2010 will remain in AOCI until such time that our cavern is emptied and the base gas is sold.

NGL Proprietary Trading

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period earnings.

Commodity Cash Flow Protection Activities at DCP Partners

As a result of DCP Partner’s operations of gathering, processing and transporting natural gas, DCP Partners takes title to a portion of residue gas, NGLs and condensate, which are considered to be Partners’ equity volumes. The possession of and the related operations of transporting and marketing of NGLs, creates commodity price risk due to market changes in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. DCP Partners has mitigated a portion of their expected natural gas, NGL and condensate commodity price risk associated with these equity volumes through 2014 with natural gas, crude oil and NGL derivatives. These transactions are primarily accomplished through the use of swaps that exchange DCP Partners floating rate price risk for a fixed rate, but the type of instrument that is used to mitigate risk may vary depending upon DCP Partners’ risk objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within current period earnings.

Interest Rate Risk

We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to hedge interest rate risk associated with our debt. Our primary goals include (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates based on historical rates.

Depending upon our risk objectives and changes in our business as well as the broader market, we may periodically elect to discontinue certain of our interest rate hedging relationships. We previously had interest rate cash flow hedges in place that were terminated in 2000. As a result, the remaining net loss deferred in AOCI relative to these cash flow hedges will be reclassified to interest expense through the remaining term of the debt through 2030, as the underlying transactions impact earnings. Additionally, we previously had fair value interest rate hedges that were terminated in 2008. As a result of this termination, the fair value of the underlying debt being hedged has been adjusted and will be amortized as a reduction to our interest expense over the remaining term of the debt through 2030. The effect of these terminated hedges on our condensed consolidated financial statements is summarized in the tables below.

Interest Rate Cash Flow Hedges

DCP Partners mitigates a portion of their interest rate risk with interest rate swaps, which reduce their 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 million of the indebtedness outstanding under Partner's revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All of Partner's 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 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. $425 million of the agreements reprice prospectively approximately every 90 days and the remaining $150 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, DCP Partners pays fixed rates ranging from 2.26% to 5.19%, and receives 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.

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.

- In the event that we were 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.
- 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 contracts, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.
- Additionally, if DCP Partners, our consolidated subsidiary, were to have an effective event of default under its credit agreement that occurs and is continuing, DCP Partners' ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.

Our commodity derivative contracts that are not governed by ISDA contracts 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 June 30, 2009, we had approximately $94 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any 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 contracts permit 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 June 30, 2009, if a credit-risk related event were to occur, we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of June 30, 2009, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $32 million

As of June 30, 2009, DCP Partner's interest rate swaps were in a net liability position of approximately $31 million, of which, the entire amount is subject to credit-risk related contingent features. If DCP Partners were to have an event of default relative to any covenants of its credit agreement, that occurs and is continuing, the counterparties to DCP Partners' swap instruments may have the right to request early termination and settlement of the outstanding derivative position.

Summarized Derivative Information

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

	June 30, 2009 (millions)
Commodity cash flow hedges:	
Net deferred losses in AOCI	$ (3)
Interest rate cash flow hedges:	
Net deferred losses in AOCI	(12)
Total AOCI	$ (15)

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

Balance Sheet Line Item	June 30, 2009 (millions)	Balance Sheet Line Item	June 30, 2009 (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	$ (19)
Unrealized gains on derivative instruments – long-term	1	Unrealized losses on derivative instruments – long-term	(13)
	$ 1		$ (32)
Commodity derivatives:		**Commodity derivatives:**	
Unrealized gains on derivative instruments – current	$ —	Unrealized losses on derivative instruments – current	$ (2)
Unrealized gains on derivative instruments – long-term	—	Unrealized losses on derivative instruments – long-term	$ —
	$ —		$ (2)
Derivative Assets Not Designated as Hedging Instruments:		**Derivative Liabilities Not Designated as Hedging Instruments:**	
Commodity derivatives:		**Commodity derivatives:**	
Unrealized gains on derivative instruments – current	$ 188	Unrealized losses on derivative instruments – current	$ (211)
Unrealized gains on derivative instruments – long-term	84	Unrealized losses on derivative instruments – long-term	(63)
	$ 272		$ (274)

The following table represents, by commodity type, our net long or short positions, as well as the number of outstanding contracts 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. Additionally, relative to the hedging of certain of our storage and/or transportation assets, we may execute basis transactions for natural gas, which may result in a net long/short position of zero. This information is included in the table below.

	June 30, 2009							
	Crude Oil		Natural Gas		Natural Gas Liquids		Natural Gas Basis Swaps	
Year of Expiration	Net Long (Short) Positions (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (Bbls)	Number of Contracts
2009	(472,929)	519	(5,961,500)	195	1,344,140	485	(5,753,500)	332
2010	(718,972)	285	(2,778,500)	55	(366,398)	195	(11,560,000)	141
2011	(875,000)	49	(949,000)	56	252,000	10	(3,420,000)	24
2012	(698,750)	10	(951,600)	4	—	—	(366,000)	1
2013	(748,250)	4	(365,000)	1	—	—	(365,000)	1
2014	(365,000)	3	—	—	—	—	—	—

Depending upon our view of the interest rate market, we or DCP Partners may periodically enter into interest rate swap agreements. As of June 30, 2009 we have no interest rate swap instruments outstanding, and DCP Partners had swaps outstanding with a notional value between $25 million and $150 million, which, in aggregate, exchanged $575 million of DCP Partners' floating rate obligation for a fixed rate obligation.

Other Risks

In addition to the risks indicated above for which we may utilize derivative physical and financial instruments to mitigate such risk, we have other risks present in our business as follows, which are currently not managed through the use of derivative physical and financial instruments:

Normal Purchases and Normal Sales

If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract's fair value in the condensed consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of commodities in future periods, as well as select operating expense contracts. These transactions will impact earnings in the same manner as any other purchase and sale that is accounted for under the accrual basis of accounting.

Credit Risk and Collateral

Our principal customers range from large, natural gas marketing services to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 40% of our NGL production is committed to ConocoPhillips and CP Chem under an existing 15-year contract, which expires in 2015. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

As of June 30, 2009, we held cash deposits of $17 million included in other current liabilities and letters of credit of $72 million from counterparties to secure their future performance under financial or physical contracts. We had cash deposits with counterparties of $2 million, included in other current assets, to secure our obligations to provide future services or to perform under financial contracts. As of June 30, 2009, DCP Partners had an outstanding letter of credit with a counterparty to its commodity derivative instruments of $10 million. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under the DCP Partners' Credit Agreement. This letter of credit reduces the amount of cash DCP Partners may be required to post as collateral. As of June 30, 2009, DCP Partners had no other cash collateral posted with counterparties to our commodity derivative instruments. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, trading and hedging contracts. In many cases, we and our counterparties publicly disclose credit ratings, which may impact the amounts of collateral requirements.

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

8. Commitments and Contingent Liabilities

Litigation — The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. Although the industry has seen these types of cases before, they were typically brought by a single plaintiff or small group of plaintiffs. A number of these cases are now being brought as class actions. We are currently named as defendants in some of these cases. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These class actions, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business, including, from time to time, disputes with customers over various measurement and settlement issues.

On February 27, 2009, a jury in the District Court, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, or El Paso, and against DCP Assets Holding, LP and an affiliate of DCP Midstream GP, LP. The lawsuit, filed in December 2006, stemmed from an ongoing commercial dispute involving DCP Partners' Minden processing plant that dates back to August 2000. During the second quarter of 2009, we filed an appeal in the 14th Court of Appeals, Texas and will continue to defend ourselves vigorously against this claim. El Paso has filed an additional lawsuit in Louisiana. We intend to defend ourselves vigorously against this claim. As a result of the jury verdict we recorded a contingent liability of approximately $5 million for this matter, which is included in other long-term liabilities in the condensed consolidated balance sheets as of June 30, 2009 and in other current liabilities in the condensed consolidated balance sheets as of December 31, 2008.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our condensed consolidated financial position.

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

9. Subsequent Events

We have evaluated subsequent events occurring through August 10, 2009, the date the financial statements were issued.

On July 28, 2009, the board of directors of DCP Partners' general partner declared a quarterly distribution of $0.60 per unit, payable on August 14, 2009 to unitholders of record on August 7, 2009.

In July 2009, we entered into interest rate swaps to convert the fixed interest rate on $500 million of debt securities under our 7.875% Notes due August 2010 and $200 million of debt securities under our 6.875% Notes due February 2011 to a floating rate. These interest rate fair value hedges are at a floating rate based on one month LIBOR, which resets monthly and is paid semi-annually through their expiration in August 2010 and February 2011, respectively.