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, 2008

or

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

For the transition period from ______ to ______

Commission File Number: 001-32678

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ 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 1, 2008, there were outstanding 24,661,754 common limited partner units and 3,571,429 subordinated units.

DCP MIDSTREAM PARTNERS, LP
FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2008

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GLOSSARY OF TERMS

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

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

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

- the level and success of natural gas drilling around our assets, and our ability to connect supplies to our gathering and processing systems in light of competition;
- our ability to grow through acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets, which will depend on general market conditions, interest rates and our ability to effectively limit a portion of the adverse effects of potential changes in interest rates by entering into derivative financial instruments, and the credit ratings for our debt obligations;
- the extent of changes in commodity prices, our ability to effectively limit a portion of the adverse impact of potential changes in prices through derivative financial instruments, and the potential impact of price on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- our ability to purchase propane from our principal suppliers for our wholesale propane logistics business;
- our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required building, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for supplies;
- the creditworthiness of counterparties to our transactions;
- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and our third-party-owned infrastructure;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the increased regulation of our industry;
- industry changes, including the impact of consolidations, increased delivery of liquefied natural gas to the United States, alternative energy sources, technological advances and changes in competition;
- the amount of collateral we may be required to post from time to time in our transactions; and
- general economic, market and business conditions.

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

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

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

	June 30, 2008	December 31, 2007
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12.3	$ 24.5
Short-term investments	1.1	1.3
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.5 million and $1.2 million, respectively	56.0	81.7
Affiliates	77.0	52.1
Inventories	39.3	37.3
Unrealized gains on derivative instruments	1.4	3.1
Other	39.2	18.5
Total current assets	226.3	218.5
Restricted investments	221.1	100.5
Property, plant and equipment, net	498.8	500.7
Goodwill	82.1	80.2
Intangible assets, net	28.8	29.7
Equity method investments	184.7	187.2
Unrealized gains on derivative instruments	2.8	2.7
Other long-term assets	1.1	1.2
Total assets	$1,245.7	$ 1,120.7
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 94.6	$ 110.2
Affiliates	37.4	55.6
Unrealized losses on derivative instruments	78.5	30.9
Accrued interest payable	0.8	1.6
Other	16.9	21.3
Total current liabilities	228.2	219.6
Long-term debt	660.0	630.0
Unrealized losses on derivative instruments	218.1	70.0
Other long-term liabilities	8.9	5.8
Total liabilities	1,115.2	925.4
Non-controlling interests	27.6	26.9
Commitments and contingent liabilities		
Partners' equity:		
Common unitholders (24,661,754 and 16,840,326 units issued and outstanding, respectively)	210.2	308.8
Subordinated unitholders (3,571,429 and 7,142,857 convertible units issued and outstanding, respectively)	(85.9)	(120.1)
General partner interest	(8.1)	(5.4)
Accumulated other comprehensive loss	(13.3)	(14.9)
Total partners' equity	102.9	168.4
Total liabilities and partners' equity	$1,245.7	$ 1,120.7

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 162.0	$ 123.6	$ 413.8	$ 301.9
Sales of natural gas, propane, NGLs and condensate to affiliates	156.5	62.0	267.4	116.6
Transportation, processing and other	2.8	3.6	8.6	6.9
Transportation, processing and other to affiliates	11.2	3.9	17.5	7.9
Losses from commodity derivative activity, net	(184.8)	(11.6)	(222.6)	(14.5)
Losses from commodity derivative activity, net — affiliates	(1.8)	(0.4)	(1.1)	(0.5)
Total operating revenues	145.9	181.1	483.6	418.3
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	238.9	129.5	486.8	292.6
Purchases of natural gas, propane and NGLs from affiliates	48.9	35.7	130.7	83.5
Operating and maintenance expense	11.0	6.3	21.6	12.9
Depreciation and amortization expense	9.0	4.5	17.5	7.9
General and administrative expense	2.4	4.5	5.0	7.0
General and administrative expense — affiliates	2.9	2.4	5.8	4.7
Other	(1.5)	—	(1.5)	—
Total operating costs and expenses	311.6	182.9	665.9	408.6
Operating (loss) income	(165.7)	(1.8)	(182.3)	9.7
Interest income	1.8	0.8	3.4	2.5
Interest expense	(7.9)	(4.6)	(16.0)	(8.4)
Earnings from equity method investments	13.4	6.4	30.6	12.8
Non-controlling interest in income	(0.9)	—	(1.5)	—
Net (loss) income	$ (159.3)	$ 0.8	$(165.8)	$ 16.6
Less:				
Net income attributable to predecessor operations	—	(0.3)	—	(3.6)
General partner interest in net income	(0.5)	(0.3)	(2.2)	(0.6)
Net (loss) income allocable to limited partners	$ (159.8)	$ 0.2	$(168.0)	$ 12.4
Net (loss) income per limited partner unit — basic and diluted	$ (5.66)	$ 0.01	$ (6.33)	$ 0.60
Weighted-average limited partner units outstanding — basic and diluted	28.2	18.0	26.6	17.8

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Millions)			
Net (loss) income	$ (159.3)	$ 0.8	$(165.8)	$16.6
Other comprehensive income (loss):				
Reclassification of cash flow hedges into earnings	2.3	(0.7)	2.7	(2.1)
Net unrealized gains (losses) on cash flow hedges	12.6	(0.4)	(1.1)	(5.7)
Total other comprehensive income (loss)	14.9	(1.1)	1.6	(7.8)
Total comprehensive (loss) income	$ (144.4)	$ (0.3)	$(164.2)	$ 8.8

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2008	2007
	(Millions)	
OPERATING ACTIVITIES:		
Net (loss) income	$(165.8)	$ 16.6
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation and amortization expense	17.5	7.9
Earnings from equity method investments, net of distributions	6.9	5.7
Non-controlling interest in income	1.5	—
Other, net	(0.8)	(0.4)
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:		
Accounts receivable	3.4	9.8
Inventories	(2.0)	(0.2)
Net unrealized losses on derivative instruments	198.9	14.9
Accounts payable	(24.2)	(14.2)
Accrued interest	(0.8)	(0.7)
Other current assets and liabilities	(21.6)	(0.2)
Other long-term assets and liabilities	(0.3)	0.6
Net cash provided by operating activities	12.7	39.8
INVESTING ACTIVITIES:		
Capital expenditures	(17.1)	(7.6)
Acquisition of subsidiaries of Momentum Energy Group, Inc.	(10.9)	—
Acquisition of assets	—	(191.3)
Investments in equity method investments	(4.4)	(3.9)
Payment of earnest deposit	—	(9.0)
Refund of earnest deposit	—	9.0
Proceeds from sales of assets	—	0.1
Purchases of available-for-sale securities	(461.9)	(6,427.7)
Proceeds from sales of available-for-sale securities	341.9	6,531.1
Net cash used in investing activities	(152.4)	(99.3)
FINANCING ACTIVITIES:		
Proceeds from debt	432.0	188.0
Payments of debt	(402.0)	(207.0)
Payment of deferred financing costs	—	(0.5)
Proceeds from issuance of common units, net of offering costs	132.1	128.5
Purchase of units	—	(0.2)
Excess purchase price over acquired assets	—	(9.9)
Net change in advances from DCP Midstream, LLC	—	(14.6)
Distributions to unitholders	(35.3)	(16.4)
Contributions from non-controlling interests	2.5	—
Distributions to non-controlling interests	(3.2)	—
Contributions from DCP Midstream, LLC	1.9	0.4
Distributions to DCP Midstream, LLC	(0.5)	—
Net cash provided by financing activities	127.5	68.3
Net change in cash and cash equivalents	(12.2)	8.8
Cash and cash equivalents, beginning of period	24.5	46.2
Cash and cash equivalents, end of period	$ 12.3	$ 55.0

See accompanying notes to condensed consolidated financial statements.

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

1. Description of Business and Basis of Presentation

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

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

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

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

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. We refer to the equity interests in East Texas and Discovery, and the Swap, for periods prior to our acquisition, collectively as our "predecessor." The condensed consolidated financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity. All significant intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations have been identified in the condensed consolidated financial statements as transactions between affiliates.

The accompanying unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission, or SEC. Accordingly, these condensed consolidated financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective interim periods. Certain information and notes normally included in our annual financial statements have been condensed or omitted from these interim financial statements pursuant to such rules and regulations. These condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the consolidated financial statements and notes thereto included in our 2007 Form 10-K.

2. Summary of Significant Accounting Policies

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

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

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

3. Recent Accounting Pronouncements

Statement of Financial Accounting Standards, or SFAS, No. 162 "The Hierarchy of Generally Accepted Accounting Principles," **or SFAS 162** — In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We do not expect the adoption of SFAS 162 to have a significant impact on our consolidated results of operations, cash flows or financial position.

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

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

SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51," **or SFAS 160 —** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 160 on our consolidated results of operations, cash flows or financial position.

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

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

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

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

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

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we recorded a cumulative effect transition adjustment of approximately $5.8 million as an increase to earnings and approximately $1.3 million as an increase to AOCI during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations as of June 30, 2008.

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

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

4. Acquisitions

Gathering and Compression Assets

In August 2007, we acquired certain subsidiaries of Momentum Energy Group, Inc., or MEG, from DCP Midstream, LLC for approximately $165.8 million. As a result of the acquisition, we expanded our operations into the Piceance and Powder River producing basins, thus diversifying our business into new operating areas. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments totaling $10.9 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of borrowings under our credit agreement, along with the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate. The proceeds from this private placement were used to purchase high-grade securities to fully secure our term loan borrowings. These units were registered with the SEC in January 2008.

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

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

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

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

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

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

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

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

equity, and the $27.6 million of common and general partner equivalent units issued as partial consideration for this transaction was recorded as an increase to partners' equity. The following tables present the impact on the condensed consolidated statements of operations, adjusted for the acquisition of East Texas, Discovery and the Swap, from DCP Midstream, LLC:

Three Months Ended June 30, 2007

	DCP Midstream Partners, LP	East Texas, Discovery and the Swap (Millions)	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 185.6	$ —	$ 185.6
Transportation and other	1.3	(5.8)	(4.5)
Total operating revenues	186.9	(5.8)	181.1
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	165.2	—	165.2
Operating and maintenance expense	6.3	—	6.3
Depreciation and amortization expense	4.5	—	4.5
General and administrative expense	6.9	—	6.9
Total operating costs and expenses	182.9	—	182.9
Operating income (loss)	4.0	(5.8)	(1.8)
Interest expense, net	(3.8)	—	(3.8)
Earnings from equity method investments	0.3	6.1	6.4
Net income	$ 0.5	$ 0.3	$ 0.8

Six Months Ended June 30, 2007

	DCP Midstream Partners, LP	East Texas, Discovery and the Swap (Millions)	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 418.5	$ —	$ 418.5
Transportation and other	8.5	(8.7)	(0.2)
Total operating revenues	427.0	(8.7)	418.3
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	376.1	—	376.1
Operating and maintenance expense	12.9	—	12.9
Depreciation and amortization expense	7.9	—	7.9
General and administrative expense	11.7	—	11.7
Total operating costs and expenses	408.6	—	408.6
Operating income (loss)	18.4	(8.7)	9.7
Interest expense, net	(5.9)	—	(5.9)
Earnings from equity method investments	0.5	12.3	12.8
Net income	$ 13.0	$ 3.6	$ 16.6

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for certain costs incurred and centralized corporate functions performed by DCP Midstream, LLC on our behalf. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, totaling $63.0 million at June 30, 2008, to certain counterparties to our commodity derivative instruments. During the three months ended June 30, 2008 and 2007, we incurred $2.5 million and $1.8 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $0.4 million and $0.6 million, respectively. During the six months ended June 30, 2008 and 2007, we incurred $4.9 million and $3.5 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $0.9 million and $1.2 million, respectively.

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Other Agreements and Transactions with DCP Midstream, LLC

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

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

In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for certain Discovery capital projects, which were forecasted to be completed prior to our acquisition of a 40% limited liability company interest in Discovery. DCP Midstream, LLC has made capital contributions of $1.6 million to us during the six months ended June 30, 2008 to reimburse us for these capital projects.

Spectra Energy

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

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

ConocoPhillips

We have multiple agreements whereby we provide a variety of services for ConocoPhillips and its affiliates. The agreements include fee-based and percentage-of-proceeds gathering and processing arrangements, gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received $1.3 million and $1.5 million of capital reimbursements during the six months ended June 30, 2008 and 2007, respectively.

Summary of Transactions with Affiliates

The following table summarizes the transactions with affiliates:

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$ 155.5	$ 59.3	$265.6	$113.9
Transportation, processing and other	$ 6.2	$ 1.3	$ 11.7	$ 2.9
Purchases of natural gas, propane and NGLs	$ 28.2	$ 30.0	$103.4	$ 70.0
Losses from commodity derivative activity, net	$ (1.8)	$ (0.4)	$ (1.1)	$ (0.5)
General and administrative expense	$ 2.9	$ 2.4	$ 5.8	$ 4.7
Spectra Energy:				
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 0.2	$ —
Transportation, processing and other	$ 0.1	$ —	$ 0.1	$ —
Purchases of natural gas, propane and NGLs	$ 4.4	$ —	$ 4.4	$ —
ConocoPhillips:				
Sales of natural gas, propane, NGLs and condensate	$ 1.0	$ 2.7	$ 1.6	$ 2.7
Transportation, processing and other	$ 4.9	$ 2.6	$ 5.7	$ 5.0
Purchases of natural gas, propane and NGLs	$ 16.3	$ 5.7	$ 22.9	$ 13.5

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

	June 30, 2008	December 31, 2007
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 72.6	$ 47.3
Accounts payable	$ 29.2	$ 53.3
Spectra Energy:		
Accounts receivable	$ 0.8	$ 1.5
Accounts payable	$ 0.3	$ —
ConocoPhillips:		
Accounts receivable	$ 3.6	$ 3.3
Accounts payable	$ 7.9	$ 2.3

6. Fair Value Measurement

Determination of Fair Value

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

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

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in an inactive (or less active) market for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

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

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

Valuation Hierarchy

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

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

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

Commodity Derivative Assets and Liabilities

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

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

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

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

Interest Rate Derivative Assets and Liabilities

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

Short-Term and Restricted Investments

We are required to post collateral to secure the term loan portion of our credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated tax-exempt debt securities that have stated maturities of 20 years or less, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. Given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper and highly rated tax-exempt debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2.

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

	Total Carrying Value	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)
		(Millions)		
Current assets:				
Short-term investments	$ 1.1	$ —	$ 1.1	$ —
Commodity derivative instruments (a)	$ 1.4	$ —	$ 0.4	$ 1.0
Long-term assets:				
Restricted investments	$ 221.1	$ —	$ 221.1	$ —
Commodity derivative instruments (b)	$ 1.6	$ —	$ —	$ 1.6
Interest rate instruments (b)	$ 1.2	$ —	$ 1.2	$ —
Current liabilities (c):				
Commodity derivative instruments	$ (71.2)	$ —	$ (63.7)	$ (7.5)
Interest rate instruments	$ (7.3)	$ —	$ (7.3)	$ —
Long-term liabilities (d):				
Commodity derivative instruments	$ (212.9)	$ —	$ (205.2)	$ (7.7)
Interest rate instruments	$ (5.2)	$ —	$ (5.2)	$ —

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

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

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

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

Changes in Level 3 Fair Value Measurements

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

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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, 2007	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, 2008	Net Unrealized Gains (Losses) Still Held Included in Earnings (b)
			(Millions)			
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 fair value as of the end of the period and amounts transferred out are reflected at fair value at the beginning of the period.

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

7. Debt

Long-term debt was as follows:

	June 30, 2008	December 31, 2007
	(Millions)	
Revolving credit facility, weighted-average interest rate of 3.19% and 5.47%, respectively, due June 21, 2012 (a)	$440.0	$ 530.0
Term loan facility, interest rate of 2.59% and 5.05%, respectively, due June 21, 2012	220.0	100.0
Total long-term debt	$660.0	$ 630.0

(a) $425.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 3.97% to 5.19%, for a net effective rate of 5.16% on the $440.0 million of outstanding debt under our revolving credit facility as of June 30, 2008.

Credit Agreement

We have a 5-year credit agreement, or the Credit Agreement, consisting of a $630.0 million revolving credit facility and a $220.0 million term loan facility. 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, 2008 and December 31, 2007. The unused portion of the revolving credit facility may be used for general corporate purposes and letters of credit. At June 30, 2008 and December 31, 2007, we had $0.3 million and $0.2 million of letters of credit outstanding under the Credit Agreement, respectively. As of June 30, 2008, the available capacity under our revolving credit facility was $189.7 million.

Other Agreements

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

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8. Partnership Equity and Distributions

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

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

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

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

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

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

Subordinated Units **—** All of the subordinated units are held by DCP Midstream, LLC. Our partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to $0.35 per common unit, or the Minimum Quarterly Distribution, plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The subordination period has an early termination provision that permits 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2008 and the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in the partnership agreement are satisfied. We determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2008 and, therefore, 50% of the subordinated units, or 3,571,428 units, converted into common units. Our board of directors certified that all conditions for early conversion were satisfied. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

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

- *first*, to the common unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second*, to the common unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;
- *third*, to the subordinated unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth*, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter (the First Target Distribution);
- *fifth*, 13% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter (the Second Target Distribution);
- *sixth*, 23% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter (the Third Target Distribution); and
- *thereafter*, 48% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders (the Fourth Target Distribution).

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

- *first*, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;
- *second*, 13% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;
- *third*, 23% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and
- *thereafter*, 48% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders.

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

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

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

9. Risk Management and Hedging Activities

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Millions)			
Commodity cash flow hedges:				
(Losses) gains reclassified into earnings	$ (0.1)	$ 0.6	$ (0.4)	$ 1.8
Commodity derivative activity:				
Unrealized losses from derivative activity	$ (170.3)	$ (12.0)	$(198.3)	$(14.9)
Realized losses from derivative activity	$ (16.3)	$ —	$ (25.4)	$ (0.1)
Interest rate cash flow hedges:				
(Losses) gains reclassified into earnings	$ (2.2)	$ 0.1	$ (2.3)	$ 0.3

	June 30, 2008	December 31, 2007
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (2.2)	$ (2.6)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	$ (11.1)	$ (12.3)

For the three and six months ended June 30, 2008 and 2007, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

As of June 30, 2008, we had outstanding letters of credit with counterparties to our commodity derivative instruments of $75.0 million. These letters of credit reduce the amount of cash we may be required to post as collateral. As of June 30, 2008, we had cash collateral posted with certain counterparties to our commodity derivative instruments of approximately $39.1 million, which is included in other current assets on the condensed consolidated balance sheets.

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

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. Therefore, we are using the mark-to-market method of accounting for all commodity derivative instruments. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings. Deferred net losses of $1.0 million are expected to be reclassified during the next 12 months. Subsequent to July 1, 2007, the changes in fair value of financial derivatives are included in losses from commodity derivative activity, net, in the condensed consolidated statements of operations. The agreements are with major financial institutions, which management expects to fully perform under the terms of the agreements.

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

Interest Rate Cash Flow Hedges — We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $425.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheets. Deferred net losses of $7.0 million on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to

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its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 3.97% to 5.19%, and receive interest payments based on the three-month London Interbank Offered Rate, or LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which management expects to fully perform under the terms of the agreements.

10. Net (Loss) Income per Limited Partner Unit

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

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

These required disclosures do not impact our overall net income or loss, or other financial results; however, in periods in which aggregate net income exceeds the First Target Distribution Level, it will have the impact of reducing net income per limited partner unit, or LPU. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of Available Cash and not earnings. In periods in which our aggregate net income does not exceed the First Target Distribution Level, there is no impact on our calculation of earnings per LPU. During the three months ended June 30, 2008 and 2007, our aggregate net income per LPU was less than the First Target Distribution level, and as a result no additional earnings were allocated to the general partner.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Millions)			
Net (loss) income	$ (159.3)	$ 0.8	$(165.8)	$16.6
Less:				
Net income attributable to predecessor operations	—	(0.3)	—	(3.6)
Net (loss) income attributable to the partnership	(159.3)	0.5	(165.8)	13.0
Less: General partner interest in net income	(0.5)	(0.3)	(2.2)	(0.6)
Limited partners' interest in net (loss) income	(159.8)	0.2	(168.0)	12.4
Less: Additional earnings allocation to general partner	—	—	—	(1.8)
Net (loss) income available to limited partners	$ (159.8)	$ 0.2	$(168.0)	$10.6
Net (loss) income per LPU — basic and diluted	$ (5.66)	$ 0.01	$ (6.33)	$0.60

11. Commitments and Contingent Liabilities

Litigation — We are a party to various legal proceedings, as well as administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our consolidated results of operations, financial position, or cash flows. See Note 16 in Item 8 of our 2007 Form 10-K for additional details.

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

12. Business Segments

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

Natural Gas Services — The Natural Gas Services segment consists of (1) our Northern Louisiana natural gas gathering, processing and transportation system; (2) our Southern Oklahoma system, acquired in May 2007; (3) our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and the Swap, acquired in July 2007; and (4) our Colorado and Wyoming systems, acquired in August 2007.

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

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

These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The following tables set forth our segment information:

Three Months Ended June 30, 2008

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 48.9	$ 94.3	$ 2.7	$ —	$ 145.9
Gross margin (a)	$ (146.2)	$ 2.4	$ 1.9	$ —	$(141.9)
Operating and maintenance expense	(8.1)	(2.7)	(0.2)	—	(11.0)
Depreciation and amortization expense	(8.4)	(0.3)	(0.3)	—	(9.0)
General and administrative expense	—	—	—	(5.3)	(5.3)
Other	—	1.5	—	—	1.5
Earnings from equity method investments	13.2	—	0.2	—	13.4
Interest income	—	—	—	1.8	1.8
Interest expense	—	—	—	(7.9)	(7.9)
Non-controlling interest in income	(0.9)	—	—	—	(0.9)
Net (loss) income	$ (150.4)	$ 0.9	$ 1.6	$(11.4)	$(159.3)
Non-cash derivative mark-to-market (b)	$ (170.2)	$ (0.2)	$ —	$ 0.1	$(170.3)
Capital expenditures	$ 6.6	$ 1.2	$ 0.1	$ —	$ 7.9

Three Months Ended June 30, 2007

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenues	$ 104.2	$ 75.2	$ 1.7	$ —	$181.1
Gross margin (a)	$ 11.1	$ 3.8	$ 1.0	$ —	$ 15.9
Operating and maintenance expense	(3.9)	(2.1)	(0.3)	—	(6.3)
Depreciation and amortization expense	(3.8)	(0.2)	(0.5)	—	(4.5)
General and administrative expense	—	—	—	(6.9)	(6.9)
Earnings from equity method investments	6.1	—	0.3	—	6.4
Interest income	—	—	—	0.8	0.8
Interest expense	—	—	—	(4.6)	(4.6)
Net income (loss)	$ 9.5	$ 1.5	$ 0.5	$(10.7)	$ 0.8
Non-cash derivative mark-to-market (b)	$ (11.6)	$ (0.3)	$ —	$ —	$ (11.9)
Capital expenditures	$ 2.3	$ 1.4	$ 0.5	$ —	$ 4.2

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Six Months Ended June 30, 2008

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 182.3	$ 296.0	$ 5.3	$ —	$ 483.6
Gross margin (a)	$ (148.7)	$ 11.0	$ 3.8	$ —	$(133.9)
Operating and maintenance expense	(15.8)	(5.4)	(0.4)	—	(21.6)
Depreciation and amortization expense	(16.2)	(0.6)	(0.7)	—	(17.5)
General and administrative expense	—	—	—	(10.8)	(10.8)
Other	—	1.5	—	—	1.5
Earnings from equity method investments	30.0	—	0.6	—	30.6
Interest income	—	—	—	3.4	3.4
Interest expense	—	—	—	(16.0)	(16.0)
Non-controlling interest in income	(1.5)	—	—	—	(1.5)
Net (loss) income	$ (152.2)	$ 6.5	$ 3.3	$(23.4)	$(165.8)
Non-cash derivative mark-to-market (b)	$ (201.2)	$ 2.5	$ —	$ (0.2)	$(198.9)
Capital expenditures	$ 14.9	$ 2.0	$ 0.2	$ —	$ 17.1

Six Months Ended June 30, 2007

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenues	$ 187.7	$ 227.0	$ 3.6	$ —	$418.3
Gross margin (a)	$ 25.3	$ 14.6	$ 2.3	$ —	$ 42.2
Operating and maintenance expense	(7.2)	(5.3)	(0.4)	—	(12.9)
Depreciation and amortization expense	(6.7)	(0.4)	(0.8)	—	(7.9)
General and administrative expense	—	—	—	(11.7)	(11.7)
Earnings from equity method investments	12.3	—	0.5	—	12.8
Interest income	—	—	—	2.5	2.5
Interest expense	—	—	—	(8.4)	(8.4)
Net income (loss)	$ 23.7	$ 8.9	$ 1.6	$(17.6)	$ 16.6
Non-cash derivative mark-to-market (b)	$ (14.5)	$ (0.4)	$ —	$ —	$ (14.9)
Capital expenditures	$ 4.1	$ 2.6	$ 0.9	$ —	$ 7.6

	June 30, 2008	December 31, 2007
	(Millions)	
Segment long-term assets:		
Natural Gas Services	$ 705.5	$ 710.7
Wholesale Propane Logistics	54.4	52.6
NGL Logistics	34.8	34.8
Other (c)	224.7	104.1
Total long-term assets	1,019.4	902.2
Current assets	226.3	218.5
Total assets	$1,245.7	$ 1,120.7

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

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

13. Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2008	2007
	(Millions)	
Cash paid for interest, net of amounts capitalized	$14.3	$10.0
Non-cash investing and financing activities:		
Net decrease in property, plant and equipment	$ (6.1)	$ (2.4)

14. Subsequent Events

During the second quarter of 2008, we announced that DCP Midstream, LLC plans to offer to sell its 75% interest in East Texas to us. The closing of this transaction may be deferred beyond our original 2008 target date.

On July 24, 2008, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on August 14, 2008 to unitholders of record on August 7, 2008. This distribution of $0.60 per unit places us in the Fourth Target Distribution level (see Note 8 for discussion of distributions of available cash).

In July 2008, we received a distribution of $8.8 million from Discovery for the second quarter of 2008.

In July 2008, DCP Midstream issued parental guarantees totaling $200.0 million to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We pay DCP Midstream a fee of 0.5% per annum on these outstanding guarantees.

During the third quarter of 2008, we announced plans to invest, along with the partners to our joint venture, approximately $150.0 million over a multi-year period to construct a gathering pipeline to support our Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. Our interest in this pipeline is 70%.

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

During the third quarter of 2008, we announced plans, along with M2 Midstream, LLC, an unaffiliated entity, to pursue development of a natural gas pipeline in northern Louisiana.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and the consolidated financial statements and notes thereto included in our 2007 Form 10-K. We refer to the our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, and our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, as well as a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007, collectively as our "predecessor." The financial information contained herein includes, for each period presented, our accounts, and those of our predecessor.

Overview

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

- our Natural Gas Services segment, which consists of (1) our Northern Louisiana natural gas gathering, processing and transportation system; (2) our Southern Oklahoma system acquired in May 2007; (3) our limited liability company interest in East Texas, our limited liability company interest in Discovery, and the Swap, acquired in July 2007 from DCP Midstream, LLC; and (4) our Colorado and Wyoming systems, acquired in August 2007 from DCP Midstream, LLC, which were acquired by DCP Midstream, LLC from Momentum Energy Group, Inc. in August 2007 (referred to as the MEG acquisition);
- our Wholesale Propane Logistics segment, which consists of six owned rail terminals, one of which is currently idle, one leased marine terminal, one pipeline terminal that became operational in May 2007, and access to several open-access pipeline terminals; and
- our NGL Logistics segment, which consists of our Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline.

Recent Events

During the second quarter of 2008, we announced that DCP Midstream, LLC plans to offer to sell its 75% interest in East Texas to us. The closing of this transaction may be deferred beyond our original 2008 target date.

During the second quarter of 2008, we issued letters of credit totaling $50.0 million to counterparties to our commodity derivative instruments, which reduce the amount of cash we may be required to post as collateral. These letters of credit were issued directly by financial institutions and do not reduce the available capacity under our credit facility.

Thomas E. Long, vice president and chief financial officer of our general partner, resigned effective April 30, 2008. Our general partner is currently conducting a search for Mr. Long's replacement.

During the second quarter of 2008, we received $1.5 million from a supplier to our Wholesale Propane Logistics segment related to the early termination of its supply agreement. This agreement was set to expire in the second quarter of 2009.

During the second quarter of 2008, we entered into a propane supply agreement with Spectra Energy. The propane supply agreement, effective May 1, 2008 and terminating April 30, 2014, provides us propane supply at our marine terminal for up to approximately 120 million gallons of propane annually.

During the second quarter of 2008, we completed pipeline integrity testing at our Wyoming system. Based on results, we curtailed certain volumes and reduced operating pressures in the pipeline, which decreased the volume of natural gas gathered. Over the next six months, we anticipate decreased operating revenues and increased operating costs as we address the results of the testing. We anticipate spending approximately $2.0 million to $3.0 million over the next two to three months to repair the pipeline.

On July 24, 2008, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on August 14, 2008 to unitholders of record on August 7, 2008. This distribution of $0.60 per unit places us in the Fourth Target Distribution level (see Note 8 of the Notes to Condensed Consolidated Financial Statements in Item 1. "Financial Statements" for discussion of distributions of available cash).

In July 2008, we received distributions of $8.8 million from Discovery, in June 2008 we received distributions of $7.9 million from East Texas, and in June 2008 we paid a contribution of $1.6 million to East Texas to fund capital expansion.

In July 2008, DCP Midstream issued parental guarantees totaling $200.0 million to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We pay DCP Midstream a fee of 0.5% per annum on these outstanding guarantees.

During the third quarter of 2008, we announced plans to invest, along with the partners to our joint venture, approximately $150.0 million over a multi-year period to construct a gathering pipeline to support our Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. Our interest in this pipeline is 70%.

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

During the third quarter of 2008, we announced plans, along with M2 Midstream, LLC, an unaffiliated entity, to pursue development of a natural gas pipeline in northern Louisiana. If constructed, this pipeline is expected to be operational during the third quarter of 2009.

Factors That Significantly Affect Our Results

In July 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap, which are collectively referred to as our predecessor, from DCP Midstream, LLC, in a transaction among entities under common control. Accordingly, our financial information includes the historical results of our predecessor for each period presented. Prior to July 2007, our financial statements do not give effect to various items that affected our results of operations and liquidity following this acquisition, including the indebtedness we incurred in conjunction with the closing of this acquisition, which increased our interest expense from the interest expense reflected in our historical financial statements.

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

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

We have mitigated a portion of the anticipated commodity price risk associated with the equity volumes from our gathering and processing operations and certain wholesale propane sales, for both our consolidated entities and our proportionate share of exposure from our equity method investments, through 2013 with natural gas, NGL and crude oil swaps. We mark these derivative instruments to market through current period earnings based upon their fair value. While the swaps mitigate the variability of our future cash flows resulting from changes in commodity prices, the mark-to-market method of accounting significantly increases the volatility of our net income because we recognize, in current period operating revenues, all non-cash gains and losses from the changes in the fair value of these derivatives.

We primarily use crude oil swaps to mitigate the 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. In addition, we will be required to provide cash collateral or letters of credit if the fair value of a derivative exceeds the collateral threshold set by the counterparty. Our collateral requirements may be significant.

For the six months ended June 30, 2008, the net loss recorded in operating revenues for commodity derivatives was $223.7 million. Of the loss, $25.4 million was related to cash settlements during 2008. The fair value of commodity derivatives was a net liability of $281.1 million as of June 30, 2008. Prior to our initial public offering, DCP Midstream provided parental guarantees, which currently total $63.0 million, to certain counterparties to our commodity derivative instruments. In July 2008, DCP Midstream provided additional parental guarantees totaling $200.0 million to certain counterparties to our commodity derivative instruments. As of August 1, 2008, we had letters of credit totaling $75.0 million. These parental guarantees and letters of credit reduce the amount of cash we may be required to post as collateral. As of August 1, 2008, we had no cash collateral posted with counterparties.

During the second quarter of 2008, we completed pipeline integrity testing at our Wyoming system. Based on results, we curtailed certain volumes and reduced operating pressures in the pipeline, which decreased the volume of natural gas gathered. Over the next six months, we anticipate decreased operating revenues and increased operating costs as we address the results of the testing. We anticipate spending approximately $2.0 million to $3.0 million over the next two to three months to repair the pipeline.

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

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

The Black Lake pipeline has experienced increased operating costs due to pipeline integrity testing that commenced in 2005 and was completed during the second quarter of 2008. We expect that our results of operations related to our equity interest in the Black Lake pipeline will benefit in 2008 from the completion of this pipeline integrity testing, although it is possible that the integrity testing will result in the need for pipeline repairs, in which case the operations of this pipeline may be interrupted while the repairs are being made. DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing. We are assessing the amount of repairs necessary, if any, as a result of this testing. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Any reimbursement of these expenses from DCP Midstream, LLC will be recognized by us as a capital contribution. We have not made any capital contributions to Black Lake associated with repairing the Black Lake pipeline.

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

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

Our Operations

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

Natural Gas Services Segment

Results of operations from our Natural Gas Services segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our gathering, processing and pipeline systems; the volumes of NGLs and condensate sold; and the level of our realized natural gas, NGL and condensate prices. We generate our revenues and our gross margin for our Natural Gas Services segment principally 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.
- *Percentage-of-proceeds/index arrangements* — Under percentage-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percentage-of-proceeds/index arrangements correlate directly with the price of natural gas and/or NGLs.

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

We have mitigated a portion of our anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with natural gas and crude oil swaps. With these swaps, we expect our cash flow exposure to commodity price movements to be reduced. For additional information regarding our derivative activities, please read “— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Commodity Cash Flow Protection Activities” in our 2007 Form 10-K and “Item 3. Quantitative and Qualitative Disclosures about Market Risk” in this Quarterly Report on Form 10-Q.

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

The natural gas supply for our gathering pipelines and processing plants is derived primarily from natural gas wells located in Colorado, Louisiana, Oklahoma, Texas, Wyoming and the Gulf of Mexico. The Pelico system also receives natural gas produced in Texas through its interconnect with other pipelines that transport natural gas from Texas into western Louisiana. These areas have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. Our two primary suppliers of natural gas in our Natural Gas Services segment represented approximately 44% of the 367 MMcf/d of natural gas supplied to this system during the six months ended June 30, 2008. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been released from other gathering systems.

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

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the Midwest and northeastern United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Midwest and the northeastern areas of the United States. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our three primary suppliers of propane, one of which is an affiliated entity, represented approximately 87% of our propane supplied during the six months ended June 30, 2008. We sell propane on a wholesale basis to retail propane distributors who in turn resell propane to their retail customers.

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

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

NGL Logistics Segment

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

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes; (2) gross margin, segment gross margin and adjusted segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) EBITDA and adjusted EBITDA; and (5) distributable cash flow. Gross margin, segment gross margin, adjusted segment gross margin, EBITDA, adjusted EBITDA and distributable cash flow measurements are not accounting principles generally accepted in the United States of America, or GAAP, financial measures. We provide reconciliations of certain non-GAAP measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

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

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

We define gross margin as total operating revenues less purchases of natural gas, propane and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases for that segment. Our gross margin equals the sum of our segment gross margins. We define adjusted segment gross margin as segment gross margin plus non-cash derivative losses, less non-cash derivative gains for that segment. Gross margin, segment gross margin and adjusted 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, 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,	
	2008	2007	2008	2007
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of net (loss) income to gross margin:				
Net (loss) income	$ (159.3)	$ 0.8	$(165.8)	$ 16.6
Interest expense	7.9	4.6	16.0	8.4
Operating and maintenance expense	11.0	6.3	21.6	12.9
Depreciation and amortization expense	9.0	4.5	17.5	7.9
General and administrative expense	5.3	6.9	10.8	11.7
Other	(1.5)	—	(1.5)	—
Non-controlling interest in income	0.9	—	1.5	—
Interest income	(1.8)	(0.8)	(3.4)	(2.5)
Earnings from equity method investments	(13.4)	(6.4)	(30.6)	(12.8)
Gross margin	$ (141.9)	$ 15.9	$(133.9)	$ 42.2
Non-cash derivative mark-to-market (a)	$ (170.3)	$ (11.9)	$(198.9)	$(14.9)
Reconciliation of segment net (loss) income to segment gross margin:				
Natural Gas Services segment:				
Segment net (loss) income	$ (150.4)	$ 9.5	$(152.2)	$ 23.7
Operating and maintenance expense	8.1	3.9	15.8	7.2
Depreciation and amortization expense	8.4	3.8	16.2	6.7
Non-controlling interest in income	0.9	—	1.5	—
Earnings from equity method investments	(13.2)	(6.1)	(30.0)	(12.3)
Segment gross margin	$ (146.2)	$ 11.1	$(148.7)	$ 25.3
Non-cash derivative mark-to-market (a)	$ (170.2)	$ (11.6)	$(201.2)	$(14.5)
Wholesale Propane Logistics segment:				
Segment net income	$ 0.9	$ 1.5	$ 6.5	$ 8.9
Operating and maintenance expense	2.7	2.1	5.4	5.3
Depreciation and amortization expense	0.3	0.2	0.6	0.4
Other	(1.5)	—	(1.5)	—
Segment gross margin	$ 2.4	$ 3.8	$ 11.0	$ 14.6
Non-cash derivative mark-to-market (a)	$ (0.2)	$ (0.3)	$ 2.5	$ (0.4)
NGL Logistics segment:				
Segment net income	$ 1.6	$ 0.5	$ 3.3	$ 1.6
Operating and maintenance expense	0.2	0.3	0.4	0.4
Depreciation and amortization expense	0.3	0.5	0.7	0.8
Earnings from equity method investment	(0.2)	(0.3)	(0.6)	(0.5)
Segment gross margin	$ 1.9	$ 1.0	$ 3.8	$ 2.3

(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. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, which currently total $63.0 million, to certain counterparties to our commodity derivative instruments. We anticipate incurring a total of $9.7 million for all fees under the Omnibus Agreement in 2008. During the three months ended June 30, 2008 and 2007, we incurred $2.5 million and $1.8 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $0.4 million and $0.6 million, respectively. During the six months ended June 30, 2008 and 2007, we incurred $4.9 million and $3.5 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $0.9 million and $1.2 million, respectively. We also incurred third party general and administrative fees of $2.4 million and $5.0 million, and $4.5 million and $7.0 million, for the three and six months ended June 30, 2008 and 2007, respectively.

The Omnibus Agreement also addresses the following matters:

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

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

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

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

EBITDA, Adjusted EBITDA and Distributable Cash Flow — We define EBITDA as net income less interest income, plus interest expense, income tax expense and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus non-cash derivative losses, less non-cash derivative gains. EBITDA and adjusted EBITDA are used as supplemental liquidity measures by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures. EBITDA is also a financial measurement that is reported to our lenders, and used as a gauge for compliance with our financial covenants under our credit facility, which requires us to maintain: (1) a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters following the consummation of asset acquisitions in the midstream energy business (including the quarter in which such acquisition is consummated), of not more than 5.50 to 1.0; and (2) an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal to or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination. Our EBITDA and adjusted EBITDA may not be comparable to similarly titled measures of another company because other entities may not calculate these measures in the same manner.

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

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

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

We define distributable cash flow as net cash provided by operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities (see "— Liquidity and Capital Resources" 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. The following table sets forth reconciliations of EBITDA from its most directly comparable financial measures calculated in accordance with GAAP:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of net (loss) income to EBITDA:				
Net (loss) income	$ (159.3)	$ 0.8	$(165.8)	$ 16.6
Interest income	(1.8)	(0.8)	(3.4)	(2.5)
Interest expense	7.9	4.6	16.0	8.4
Depreciation and amortization expense	9.0	4.5	17.5	7.9
EBITDA	$ (144.2)	$ 9.1	$(135.7)	$ 30.4
Reconciliation of net cash (used in) provided by operating activities to EBITDA:				
Net cash (used in) provided by operating activities	$ (12.4)	$ 20.0	$ 12.7	$ 39.8
Interest income	(1.8)	(0.8)	(3.4)	(2.5)
Interest expense	7.9	4.6	16.0	8.4
Earnings from equity method investments, net of distributions	(4.9)	(6.5)	(6.9)	(5.7)
Net changes in operating assets and liabilities	(132.4)	(8.1)	(153.4)	(10.0)
Other, net	(0.6)	(0.1)	(0.7)	0.4
EBITDA	$ (144.2)	$ 9.1	$(135.7)	$ 30.4

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

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

- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

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

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2007 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the six months ended June 30, 2008 are the same as those described in our 2007 Form 10-K.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2008 and 2007. 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 2008 vs. 2007		Variance Six Months 2008 vs. 2007	
	2008 (a)	2007 (a)	2008 (a)	2007 (a)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Natural Gas Services (b)	$ 48.9	$ 104.2	$ 182.3	$ 187.7	$ (55.3)	(53)%	$ (5.4)	(3)%
Wholesale Propane Logistics	94.3	75.2	296.0	227.0	19.1	25%	69.0	30%
NGL Logistics	2.7	1.7	5.3	3.6	1.0	59%	1.7	47%
Total operating revenues	145.9	181.1	483.6	418.3	(35.2)	(19)%	65.3	16%
Gross margin (c):								
Natural Gas Services	(146.2)	11.1	(148.7)	25.3	(157.3)	*	(174.0)	*
Wholesale Propane Logistics	2.4	3.8	11.0	14.6	(1.4)	(37)%	(3.6)	(25)%
NGL Logistics	1.9	1.0	3.8	2.3	0.9	90%	1.5	65%
Total gross margin	(141.9)	15.9	(133.9)	42.2	(157.8)	*	(176.1)	*
Operating and maintenance expense	(11.0)	(6.3)	(21.6)	(12.9)	4.7	75%	8.7	67%
General and administrative expense	(5.3)	(6.9)	(10.8)	(11.7)	(1.6)	(23)%	(0.9)	(8)%
Other	1.5	—	1.5	—	1.5	*	1.5	*
Earnings from equity method investments (d)	13.4	6.4	30.6	12.8	7.0	109%	17.8	139%
Non-controlling interest in income	(0.9)	—	(1.5)	—	0.9	*	1.5	*
EBITDA (e)	(144.2)	9.1	(135.7)	30.4	(153.3)	*	(166.1)	*
Depreciation and amortization expense	(9.0)	(4.5)	(17.5)	(7.9)	4.5	100%	9.6	122%
Interest income	1.8	0.8	3.4	2.5	1.0	125%	0.9	36%
Interest expense	(7.9)	(4.6)	(16.0)	(8.4)	3.3	72%	7.6	90%
Net (loss) income	$ (159.3)	$ 0.8	$ (165.8)	$ 16.6	$ (160.1)	*	$ (182.4)	*
Operating data:								
Natural gas throughput (MMcf/d) (d)	835	733	831	716	102	14%	115	16%
NGL gross production (Bbls/d) (d)	23,769	21,563	24,480	20,207	2,206	10%	4,273	21%
Propane sales volume (Bbls/d)	14,442	16,179	24,178	25,715	(1,737)	(11)%	(1,537)	(6)%
NGL pipelines throughput (Bbls/d) (d)	34,286	28,376	33,081	27,917	5,910	21%	5,164	18%

* Percentage change is not meaningful.

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

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

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

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

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

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

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

- $175.2 million decrease related to commodity derivative activity, $0.6 million of which is included in sales of natural gas, NGLs and condensate, and $174.6 million of which is included in losses from commodity derivative activity; partially offset by
- $113.2 million increase attributable primarily to increased commodity prices, as well as higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system, for our Natural Gas Services segment;
- $19.7 million increase attributable to increased propane prices, partially offset by decreased propane sales volumes for our Wholesale Propane Logistics segment;
- $6.5 million increase in transportation, processing and other revenue, primarily attributable to the MEG acquisition in our Natural Gas Services segment; and
- $0.6 million increase attributable to increased throughput volumes and increases related to changes in product mix in our NGL Logistics segment.

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

- $157.3 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity derivative activity and lower NGL and condensate production across our Northern Louisiana system, partially offset by an increase in natural gas, NGL and condensate production as a result of the MEG and Southern Oklahoma acquisitions and increased commodity prices; and
- $1.4 million decrease for our Wholesale Propane Logistics segment primarily as a result of commodity derivative activity and lower propane sales volumes, partially offset by higher per unit margins; partially offset by
- $0.9 million increase for our NGL Logistics segment primarily due to changes in product mix and increased throughput volumes.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2008 compared to 2007, primarily as a result of the MEG and Southern Oklahoma acquisitions in our Natural Gas Services segment, as well as increased labor and benefits in our Wholesale Propane Logistics segment.

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

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

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2008 compared to 2007, due to increased equity earnings of $3.9 million from East Texas and $3.2 million from Discovery, partially offset by a decrease of $0.1 million from Black Lake.

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

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

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

Six Months Ended June 30, 2008 vs. Six Months Ended June 30, 2007

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

- $195.4 million increase attributable primarily to increased commodity prices, as well as higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system, for our Natural Gas Services segment;
- $68.3 million increase attributable to increased propane prices, partially offset by decreased propane sales volumes for our Wholesale Propane Logistics segment;
- $11.3 million increase in transportation, processing and other revenue, primarily attributable to the MEG acquisition in our Natural Gas Services segment; and
- $1.2 million increase attributable primarily to increased throughput volumes and increases related to changes in product mix for our NGL Logistics segment; partially offset by
- $210.9 million decrease related to commodity derivative activity, $2.2 million of which is included in sales of natural gas, NGLs and condensate, and $208.7 million of which is included in losses from commodity derivative activity.

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

- $174.0 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity derivative activity and lower NGL and condensate production across our Northern Louisiana system, partially offset by an increase in natural gas, NGL and condensate production as a result of the MEG and Southern Oklahoma acquisitions and increased commodity prices; and
- $3.6 million decrease for our Wholesale Propane Logistics segment due to lower per unit margins, lower sales volumes, commodity derivative activity and favorable non-cash lower of cost or market inventory adjustments recognized in 2007; partially offset by
- $1.5 million increase for our NGL Logistics segment attributable primarily due to changes in product mix and increased volumes.

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

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

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

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2008 compared to 2007, due to increased equity earnings of $9.6 million from Discovery, $8.1 million from East Texas and $0.1 million from Black Lake.

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

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

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

Results of Operations — Natural Gas Services Segment

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

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2008 vs. 2007		Variance Six Months 2008 vs. 2007	
	2008 (a)	2007 (a)	2008 (a)	2007 (a)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 222.1	$ 109.5	$ 382.9	$ 189.7	$ 112.6	103%	$ 193.2	102%
Transportation, processing and other	11.3	6.3	22.0	12.3	5.0	79%	9.7	79%
Losses from commodity derivative activity (b)	(184.5)	(11.6)	(222.6)	(14.3)	172.9	*	208.3	*
Total operating revenues	48.9	104.2	182.3	187.7	(55.3)	(53)%	(5.4)	(3)%
Purchases of natural gas and NGLs	195.1	93.1	331.0	162.4	102.0	110%	168.6	104%
Segment gross margin (c)	(146.2)	11.1	(148.7)	25.3	(157.3)	*	(174.0)	*
Operating and maintenance expense	(8.1)	(3.9)	(15.8)	(7.2)	4.2	108%	8.6	119%
Depreciation and amortization expense	(8.4)	(3.8)	(16.2)	(6.7)	4.6	121%	9.5	142%
Earnings from equity method investments (d)	13.2	6.1	30.0	12.3	7.1	116%	17.7	144%
Non-controlling interest in income	(0.9)	—	(1.5)	—	0.9	*	1.5	*
Segment net (loss) income	$ (150.4)	$ 9.5	$ (152.2)	$ 23.7	$ (159.9)	*	$ (175.9)	*
Operating data:								
Natural gas throughput (MMcf/d) (d)	835	733	831	716	102	14%	115	16%
NGL gross production (Bbls/d) (d)	23,769	21,563	24,480	20,207	2,206	10%	4,273	21%

* Percentage change is not meaningful.

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

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

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

(d) Includes our proportionate share of the throughput volumes and earnings of East Texas and Discovery, and the amortization of the net difference between the carrying amount of Discovery and the underlying equity of Discovery, for all periods presented.

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

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

- $173.5 million decrease related to commodity derivative activity, $0.6 million of which is included in sales of natural gas, NGLs and condensate, and $172.9 million of which is included in losses from commodity derivative activity. This activity includes cash settlements related to our investments in East Texas and Discovery of $5.2 million which reduced operating revenues; partially offset by
- $69.8 million increase attributable to an increase in commodity prices;
- $43.4 million increase primarily attributable to higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system; and
- $5.0 million increase in transportation, processing and other revenue primarily as a result of the MEG acquisition.

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

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

- $173.5 million decrease related to commodity derivative activity, as discussed in the Operating Revenues section above; and
- $0.7 million decrease primarily attributable to changes in contract mix; partially offset by
- $11.0 million increase primarily attributable to an increase in natural gas, NGL and condensate production as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system; and
- $5.9 million increase due to increased commodity prices.

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

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

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2008 compared to 2007, due to an increase in equity earnings of $3.9 million from East Texas and $3.2 million from Discovery. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

- Increased equity earnings from East Texas were the result of an increase in East Texas' net income of $15.6 million, due primarily to a $10.5 million increase as a result of higher commodity prices, a $3.9 million increase due to increased fee-based revenue and a decrease in general and administrative expenses of $2.0 million, partially offset by an increase in operating expenses of $1.2 million.
- Increased equity earnings from Discovery were the result of an increase in Discovery's net income of $7.8 million, due primarily to $7.5 million higher NGL sales margins resulting primarily from increased per-unit margins on slightly lower NGL sales volumes, partially offset by $1.2 million higher general and administrative expense.

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

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

Six Months Ended June 30, 2008 vs. Six Months Ended June 30, 2007

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

- $210.5 million decrease related to commodity derivative activity, $2.2 million of which is included in sales of natural gas, NGLs and condensate, and $208.3 million of which is included in losses from commodity derivative activity. This activity includes cash settlements related to our investments in East Texas and Discovery of $8.1 million which reduced operating revenues; partially offset by

- $109.5 million increase attributable to an increase in commodity prices;
- $85.9 million increase primarily attributable to higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system; and
- $9.7 million increase in transportation, processing and other revenue primarily as a result of the MEG acquisition.

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

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

- $210.5 million decrease related to commodity derivative activity, as discussed in the Operating Revenues section above; partially offset by
- $25.0 million increase primarily attributable to an increase in natural gas, NGL and condensate production as a result of the MEG and Southern Oklahoma acquisitions, partially offset by lower NGL and condensate production across our Northern Louisiana system;
- $9.1 million increase due to increased commodity prices; and
- $2.4 million increase primarily attributable to changes in contract mix.

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

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

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2008 compared to 2007, due to an increase in equity earnings of $9.6 million from Discovery and an increase in equity earnings of $8.1 million from East Texas. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

- Increased equity earnings from East Texas were the result of an increase in East Texas' net income of $32.4 million, due primarily to a $21.0 million increase as a result of higher commodity prices, a $6.0 million increase due to increased fee-based revenue, a $5.5 million increase due to an increase in natural gas volumes and a decrease in general and administrative expenses of $2.6 million, partially offset by an increase in operating expenses of $2.3 million.
- Increased equity earnings from Discovery were the result of an increase in Discovery's net income of $24.0 million, due primarily to $22.4 million higher NGL sales margins resulting from increased per-unit margins on higher NGL sales volumes from volumes processed under keep-whole and percent-of liquids processing arrangements and higher plant inlet volumes, and $3.8 million for higher other income, net, partially offset by $2.4 million higher general and administrative expense.

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

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

Results of Operations — Wholesale Propane Logistics Segment

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Variance Three Months 2008 vs. 2007 Increase (Decrease)	Variance Three Months 2008 vs. 2007 Percent	Variance Six Months 2008 vs. 2007 Increase (Decrease)	Variance Six Months 2008 vs. 2007 Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of propane	$ 95.3	$ 75.6	$ 296.0	$ 227.7	$ 19.7	26%	$ 68.3	30%
Other	1.1	—	1.1	—	1.1	*	1.1	*
Losses from commodity derivative activity	(2.1)	(0.4)	(1.1)	(0.7)	1.7	425%	0.4	57%
Total operating revenues	94.3	75.2	296.0	227.0	19.1	25%	69.0	30%
Purchases of propane	91.9	71.4	285.0	212.4	20.5	29%	72.6	34%
Segment gross margin (a)	2.4	3.8	11.0	14.6	(1.4)	(37)%	(3.6)	(25)%
Operating and maintenance expense	(2.7)	(2.1)	(5.4)	(5.3)	0.6	29%	0.1	2%
Depreciation and amortization expense	(0.3)	(0.2)	(0.6)	(0.4)	0.1	50%	0.2	50%
Other	1.5	—	1.5	—	1.5	*	1.5	*
Segment net income	$ 0.9	$ 1.5	$ 6.5	$ 8.9	$ (0.6)	(40)%	$ (2.4)	(27)%
Operating data:								
Propane sales volume (Bbls/d)	14,442	16,179	24,178	25,715	(1,737)	(11)%	(1,537)	(6)%

* 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, 2008 vs. Three Months Ended June 30, 2007

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

- $27.9 million increase attributable to higher propane prices; and
- $1.1 million increase attributable to other fee revenue; partially offset by
- $8.2 million decrease attributable to decreased propane sales volumes as a result of supply disruptions and lower demand as a result of higher prices, partially offset by increased propane sales volumes due to the completion of the Midland terminal in May 2007; and
- $1.7 million decrease related to commodity derivative activity.

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

Segment Gross Margin — Segment gross margin decreased in 2008 compared to 2007, primarily as a result of commodity derivative activity and lower propane sales volumes, partially offset by higher per unit margins.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2008 compared to 2007, primarily due to increased labor and benefits.

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

Six Months Ended June 30, 2008 vs. Six Months Ended June 30, 2007

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

- $81.6 million increase attributable to higher propane prices; and
- $1.1 million increase attributable to other fee revenue; partially offset by
- $13.3 million decrease attributable to decreased propane sales volumes as a result of milder weather in portions of our markets in 2008, supply disruptions and lower demand as a result of higher prices, partially offset by increased propane sales volumes due to the completion of the Midland terminal in May 2007; and
- $0.4 million decrease related to commodity derivative activity.

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

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

Operating and Maintenance Expense — Operating and maintenance expense remained relatively constant in 2008 compared to 2007.

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

Results of Operations — NGL Logistics Segment

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

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2008 vs. 2007		Variance Six Months 2008 vs. 2007	
	2008	2007	2008	2007	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of NGLs	$ 1.1	$ 0.5	$ 2.3	$ 1.1	$ 0.6	120%	$ 1.2	109%
Transportation, processing and other	1.6	1.2	3.0	2.5	0.4	33%	0.5	20%
Total operating revenues	2.7	1.7	5.3	3.6	1.0	59%	1.7	47%
Purchases of NGLs	0.8	0.7	1.5	1.3	0.1	14%	0.2	15%
Segment gross margin (a)	1.9	1.0	3.8	2.3	0.9	90%	1.5	65%
Operating and maintenance expense	(0.2)	(0.3)	(0.4)	(0.4)	(0.1)	(33)%	—	— %
Depreciation and amortization expense	(0.3)	(0.5)	(0.7)	(0.8)	(0.2)	(40)%	(0.1)	(13)%
Earnings from equity method investment (b)	0.2	0.3	0.6	0.5	(0.1)	(33)%	0.1	20%
Segment net income	$ 1.6	$ 0.5	$ 3.3	$ 1.6	$ 1.1	220%	$ 1.7	106%
Operating data:								
NGL pipelines throughput (Bbls/d) (b)	34,286	28,376	33,081	27,917	5,910	21%	5,164	18%

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

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

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

Total Operating Revenues — Total operating revenues increased in 2008 compared to 2007, primarily due to increased transportation and other fees, increased throughput volumes and increases related to changes in product mix.

Purchases of NGLs — Purchases of NGLs remained relatively constant in 2008 compared to 2007.

Segment Gross Margin — Segment gross margin increased in 2008 compared to 2007 primarily due to changes in product mix and increased throughput volumes.

Earnings from Equity Method Investments — Earnings from equity method investments remained relatively constant in 2008 compared to 2007.

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

Six Months Ended June 30, 2008 vs. Six Months Ended June 30, 2007

Total Operating Revenues — Total operating revenues increased in 2008 compared to 2007, primarily due to increased throughput volumes, increased transportation and other fees, and increases related to changes in product mix.

Purchases of NGLs — Purchases of NGLs remained relatively constant in 2008 compared to 2007.

Segment Gross Margin — Segment gross margin increased in 2008 compared to 2007 primarily due to changes in product mix and increased throughput volumes.

Earnings from Equity Method Investments — Earnings from equity method investments remained relatively constant in 2008 compared to 2007.

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

Liquidity and Capital Resources

Our predecessor's sources of liquidity, prior to their acquisition by us, included cash generated from operations and funding from DCP Midstream, LLC. Our predecessor's cash receipts were deposited in DCP Midstream, LLC's bank accounts and all cash disbursements were made from these accounts. Cash transactions for our predecessor were handled by DCP Midstream, LLC and were reflected in partners' equity as intercompany advances from DCP Midstream, LLC.

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our equity method investments;
- borrowings under our revolving credit facility;
- cash realized from the liquidation of securities that are pledged under our term loan facility;
- issuance of additional partnership units;
- debt offerings;
- guarantees issued by DCP Midstream, which reduce the amount of cash collateral we may be required to post with certain counterparties to our commodity derivative instruments; and
- letters of credit.

We anticipate our more significant uses of resources to include:

- capital expenditures;
- contributions to our equity method investments to finance our share of their capital expenditures;
- business and asset acquisitions;
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts; and
- quarterly distributions to our unitholders.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions for the next twelve months. Our commodity derivative program, as well as any future derivatives we enter into, may require us to post collateral, which at times may be significant, depending on commodity price movements.

The counterparties to each of our swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined “collateral threshold.” Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty’s assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Prior to our initial public offering, DCP Midstream provided parental guarantees, which currently total $63.0 million, to certain counterparties to our commodity derivative instruments. In July 2008, DCP Midstream provided additional parental guarantees totaling $200.0 million to certain counterparties to our commodity derivative instruments. We also have letters of credit totaling $75.0 million. These parental guarantees and letters of credit reduce the amount of cash we may be required to post as collateral. As of August 1, 2008, we had no cash collateral posted with counterparties. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. Predetermined collateral thresholds for hedges guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC’s credit rating and the thresholds would be reduced to $0 in the event DCP Midstream, LLC’s credit rating were to fall below investment grade.

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

We had a working capital deficit of $1.9 million and $1.1 million as of June 30, 2008 and December 31, 2007, respectively. The changes in working capital are primarily attributable to the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

Cash Flow — Net cash provided by or used in operating, investing and financing activities were as follows:

	Six Months Ended June 30,	
	2008	2007
	(Millions)	
Net cash provided by operating activities	$ 12.7	$ 39.8
Net cash used in investing activities	$(152.4)	$(99.3)
Net cash provided by financing activities	$ 127.5	$ 68.3

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 paid net cash for settlements of our commodity derivative instruments during the six months ended June 30, 2008 and 2007 totaling $25.4 million and $0.1 million, respectively.

We and our predecessor received cash distributions from equity method investments of $37.5 million and $18.5 million during the six months ended June 30, 2008 and 2007, respectively. Distributions exceeded earnings by $6.9 million and $5.7 million for the six months ended June 30, 2008 and 2007, respectively.

Net Cash Used in Investing Activities — Net cash used in investing activities during the six months ended June 30, 2008 was comprised of: (1) capital expenditures of $17.1 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities; (2) acquisition of the MEG subsidiaries of $10.9 million; (3) investments in Discovery of $1.9 million and East Texas of $2.5 million; and (4) net purchases of available-for-sale securities of $120.0 million.

Net cash used in investing activities during the six months ended June 30, 2007 was comprised primarily of: (1) asset acquisitions of $191.3 million; (2) capital expenditures of $7.6 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities; and (3) investments in Discovery of $3.9 million; which were partially offset by (4) net sales of available-for-sale securities of $103.4 million.

We invested cash in equity method investments of $4.4 million and $3.9 million during the six months ended June 30, 2008 and 2007, respectively, to fund our share of capital expansion projects.

Net Cash Provided by Financing Activities — Net cash provided by financing activities during the six months ended June 30, 2008 was comprised of (1) proceeds from debt of $432.0 million; (2) proceeds from sales of common limited partner units of $132.1 million, net of offering costs; (3) contributions from non-controlling interests of $2.5 million; and (4) contributions from DCP Midstream, LLC of $1.9 million; partially offset by (5) distributions to our unitholders of $35.3 million; (6) payments of debt of $402.0 million; and (7) distributions to non-controlling interests of $3.2 million.

Net cash provided by financing activities during the six months ended June 30, 2007, was comprised of (1) proceeds from debt of $188.0 million; and (2) the issuance of common units for $128.5 million, net of offering costs; partially offset by (3) payments of debt of $207.0 million; (4) distributions to our unitholders of $16.4 million; (5) changes in advances from DCP Midstream, LLC of $14.6 million; and (6) the excess of purchase price over the acquired assets attributable to a payment related to our acquisition of our wholesale propane logistics business of $9.9 million.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 8 of the Notes to Condensed Consolidated Financial Statements in Item 1. "Financial Statements."

Capital Requirements — The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

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

- expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements made to increase our operating capacity or revenues (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets).

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

We have budgeted maintenance capital expenditures of $5.3 million and expansion capital expenditures of $2.9 million for the year ending December 31, 2008, excluding acquisitions. In addition, we anticipate maintenance capital expenditures of $2.7 million for our 25% interest in East Texas and $1.9 million for our 40% interest in Discovery for the year ending December 31, 2008. We also anticipate expansion capital expenditures of $3.0 million for our 25% interest in East Texas and $5.3 million for our 40% interest in Discovery for the year ending December 31, 2008. We may be required to contribute cash to East Texas and Discovery to cover our respective share of expansion capital expenditures at both East Texas and Discovery. DCP Midstream, LLC has agreed to reimburse us for our share of Discovery's capital expenditures for the Tahiti pipeline lateral. The board of directors may approve additional growth capital during the year, at their discretion.

Our capital expenditures, excluding acquisitions, totaled $17.1 million and $7.6 million, including maintenance capital expenditures of $2.1 million and $0.9 million, and expansion capital expenditures of $15.0 million and $6.7 million, during the six months ended June 30, 2008 and 2007, respectively. In conjunction with the acquisition of our investments in East Texas and Discovery, we entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for 25% of certain East Texas capital expenditures, and will reimburse us for 40% of certain Discovery capital expenditures, as defined in the agreement, from July 1, 2007 through completion of the capital projects, for a period not to exceed three years. We also have an agreement with certain producers whereby these producers will reimburse us for certain capital projects completed by us. As a result, during the six months ended June 30, 2008, we had an increase in receivables of $0.2 million related to collections of maintenance capital expenditures from DCP Midstream, LLC and producers. As a result, our total maintenance capital expenditures net of reimbursements totaled approximately $1.9 million for the six months ended June 30, 2008. For the six months ended June 30, 2007, our changes in receivables related to collections of maintenance capital expenditures from DCP Midstream, LLC and producers were not significant.

During the third quarter of 2008, we announced plans to invest, along with the partners to our joint venture, approximately $150.0 million over a multi-year period to construct a gathering pipeline to support our Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. Our interest in this pipeline is 70%.

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

During the third quarter of 2008, we announced plans, along with M2 Midstream, LLC, an unaffiliated entity, to pursue development of a natural gas pipeline in northern Louisiana. If constructed, this pipeline is expected to be operational during the third quarter of 2009.

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

Cash Distributions to Unitholders — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders of $35.3 million during the six months ended June 30, 2008, as compared to $16.4 million for the same period in 2007. We intend to make quarterly distribution payments to our unitholders to the extent we have sufficient cash from operations after the establishment of reserves.

Description of Amended Credit Agreement — We have a 5-year credit agreement, or the Credit Agreement, consisting of a $630.0 million revolving credit facility and a $220.0 million term loan facility. The Credit Agreement matures on June 21, 2012. We have the option of increasing the size of the revolving credit facility to $1.0 billion with the consent of the issuing lenders.

During the six months ended June 30, 2008, we borrowed $252.0 million from our revolving credit facility for general corporate purposes and $30.0 million to fund a partial retirement of our term loan facility, and we repaid $372.0 million. During the six months ended June 30, 2008, we borrowed $150.0 million from our term loan facility, and we repaid $30.0 million. As of June 30, 2008, the outstanding balance on the revolving credit facility was $440.0 million and the outstanding balance on the term loan facility was $220.0 million. As of June 30, 2008, the weighted-average effective interest rate was 5.16% per annum on the $440.0 million of outstanding debt under our revolving credit facility, and the weighted-average interest rate was 2.59% on the $220.0 million of outstanding debt under our term loan facility.

Our obligations under the revolving credit facility are unsecured, and the term loan facility is secured at all times by high-grade securities, 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 of assets in the midstream energy business. The unused portion of the revolving credit facility may be used for general corporate purposes and for letters of credit. At June 30, 2008 and December 31, 2007, we had outstanding letters of credit of $0.3 million and $0.2 million under the Credit Agreement, respectively. As of June 30, 2008, the available capacity under our revolving credit facility was $189.7 million.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

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

	Payments Due by Period				
	Total	Remainder of 2008	2009-2010	2011-2012	2013 and Thereafter
			(Millions)		
Long-term debt (a)	$ 740.0	$ 11.3	$ 45.1	$ 683.6	$ —
Operating lease obligations	39.7	4.6	15.3	12.2	7.6
Purchase obligations (b)	1,702.7	213.2	585.9	461.9	441.7
Other long-term liabilities (c)	8.4	—	0.4	0.2	7.8
Total	$2,490.8	$ 229.1	$ 646.7	$1,157.9	$ 457.1

(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 $0.1 million of purchase orders for capital expenditures and $1,702.6 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, 2008. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the condensed consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the condensed consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity. In addition, many of our gas purchase contracts include short and long term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(c) Other long-term liabilities include $7.7 million of asset retirement obligations and $0.7 million of environmental reserves recognized in the June 30, 2008 condensed consolidated balance sheet.

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

Recent Accounting Pronouncements

***Statement of Financial Accounting Standards, or SFAS, No. 162 "The Hierarchy of Generally Accepted Accounting Principles,"* or SFAS 162** — In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We do not expect the adoption of SFAS 162 to have a significant impact on our consolidated results of operations, cash flows or financial position.

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

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

***SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51,"* or SFAS 160 —** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 160 on our consolidated results of operations, cash flows or financial position.

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

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

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

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

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

The adoption of this standard resulted in us making slight changes to our valuation methodologies to incorporate the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we have recorded a cumulative effect transition adjustment of approximately $5.8 million as an increase to earnings and approximately $1.3 million as an increase to accumulated other comprehensive income during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations as of June 30, 2008.

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

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

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

For an in-depth discussion of our market risks, see "Quantitative and Qualitative Disclosures about Market Risk" in our 2007 Form 10-K.

Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketing servicers and industrial end-users. Our principal customers in the Wholesale Propane Logistics segment are primarily retail propane distributors. In the NGL Logistics Segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Substantially all of our natural gas, propane and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk, as these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC's corporate credit policy. DCP Midstream, LLC's corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC's credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Interest Rate Risk

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

We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $425.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swaps re-price prospectively approximately every 90 days. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. At June 30, 2008, the effective weighted-average interest rate on our $440.0 million of outstanding revolver debt was 5.16%, taking into account the $425.0 million of indebtedness with designated interest rate swaps.

Based on the annualized unhedged borrowings under our credit facility of $235.0 million as of June 30, 2008, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $1.2 million annualized increase or decrease in interest expense.

Commodity Price Risk

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

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

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

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

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

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

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income)
			(Millions)
Natural gas prices	$ 1.00	MMBtu	$ 6.0
Crude oil prices	$ 5.00	Barrel	$ 18.2

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

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

Based on our current contract mix, we believe that during the remainder of 2008 we will have a long position in natural gas, NGLs and condensate, and will be sensitive to changes in commodity prices.

These sensitivities include the effect of settlements on our financial derivatives. Please read "— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Commodity Cash Flow Protection Activities" in our 2007 Form 10-K for more information about our commodity price risk.

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

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

Item 4. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

Our management, including the Chief Executive Officer and the Principal Accounting Officer, in the absence of a 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 Principal Accounting Officer, in the absence of a 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, 2008 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information required for this item is provided in Note 16, "Commitments and Contingent Liabilities," included in Item 8 of our 2007 Form 10-K, which information is incorporated by reference into this item.

Item 1A. Risk Factors

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed in Part I, "Item 1A. Risk Factors" in our 2007 Form 10-K. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described in our 2007 Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our consolidated results of operations, financial condition and cash flows.

The following is a new or modified risk factor that should be read in conjunction with the risk factors disclosed in our 2007 Form 10-K:

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

We are exposed to risks associated with fluctuations in commodity prices. The extent of our commodity price risk is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have primarily entered into derivative financial instruments relating to the future price of crude oil. If the price relationship between NGLs and crude oil changes, our commodity price risk may increase. Furthermore, we have entered into derivative transactions related to only a portion of the volume of our expected natural gas supply and production of NGLs and condensate from our processing plants; as a result, we will continue to have direct commodity price risk to the open portion. Our actual future production may be significantly higher or lower than we estimate at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimate, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, reducing our liquidity.

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

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

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

The counterparties to our derivative instruments may require us to post collateral in the event that our potential payment exposure exceeds a predetermined collateral threshold. As of August 1, 2008, DCP Midstream provided parental guarantees to certain counterparties to our commodity derivative instruments totaling $263.0 million and we had letters of credit totaling $75.0 million, which reduce the amount of cash we may be required to post as collateral. As of August 1, 2008, we had no cash collateral posted with counterparties. Depending on the movement in commodity prices, the amount of collateral posted may increase, reducing our liquidity.

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

Item 6. ***Exhibits***

Exhibits

Exhibit Number	Description
10.1	Propane Sales Contract, effective May 1, 2008, between Spectra Energy Propane LLC and Gas Supply Resources LLC.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Vice President & Controller, Chief Accounting Officer (Principal Accounting 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 Vice President & Controller, Chief Accounting Officer (Principal Accounting Officer) pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Unaudited Condensed Consolidated Balance Sheet of DCP Midstream GP, LP as of June 30, 2008.
99.2	Unaudited Condensed Consolidated Balance Sheet of DCP Midstream, LLC as of June 30, 2008.

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 8, 2008.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

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

By: /s/ Scott R. Delmoro
Name: Scott R. Delmoro
Title: Vice President & Controller, Chief Accounting Officer (Principal Accounting Officer)

EXHIBIT INDEX

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99.2	Unaudited Condensed Consolidated Balance Sheet of DCP Midstream, LLC as of June 30, 2008.

Execution Copy

PROPANE SALES CONTRACT

This Propane Sales Contract (this "**Contract**") is entered into effective May 1, 2008 between Spectra Energy Propane LLC ("**Seller**") and Gas Supply Resources LLC **("Buyer").** (Seller and Buyer being referred to collectively as the "**Parties**" and individually, as a "**Party**")

CONTRACT REF. NO.: 1

2. SELLER

Spectra Energy Propane LLC
5400 Wecthcimer Court
Houston TX, USA 77056
Attention: William S. Garner

3. BUYER

Gas Supply Resources LLC
5817 Westheimer, Suite 2000
Houston, TX 77057
Attention: Richard M. Paul, Jr.

4. TERM

The term of this Contract shall run during the period from May 1, 2008 to April 30, 2014, The Term shall he divided into contract years (each, a "**Contract Year**") commencing on May 1 and ending, on the next succeeding April 30.

5. ASSIGNMENT

This Contract shall extend to and be binding upon the successors and assigns of the Parties, but neither this Contract nor any part, specifically including the right to receive payment, shall be assigned or transferred by either Party or by law without the prior written consent of the other Party which shall not be unreasonably withheld, and any assignment or transfer made by either Party without the other Party's written consent need not be recognized by and shall not be binding upon the other Party.

6. GRADE AND QUALITY

Fully Refrigerated Propane (herein, the “Product”).

7. SPECIFICATIONS

All Product delivered to Buyer shall comply with GPA 2140-HD5 specifications as published by the National Gas Processors Association (NGPA) and in effect on the date that Product is unloaded into the Teppco Tidewater propane terminal located in the Port of Providence, Providence, Rhode Island (the “Delivery Point”). Ethane content shall be less than 2%. Acceptance by Buyer of Product delivered under this Contract shall constitute a waiver of any claim against Seller based on the failure of the Product to meet such specifications.

8. QUANTITY

The maximum annual quantity of Product to be delivered and received during any Contract Year the Term is 225,000 Metric Tons plus 5% Buyer’s operational tolerance, and the minimum annual quantity of Product to be delivered and received during any Contract Year during the Term is 190,000 Metric Tons less 5% Buyer’s operational tolerance. By March 31 of each year, the parties may mutually agree in writing to increase or decrease the maximum or minimum annual quantities. The annual quantity for each Contract Year shall be nominated as provided in Section 9.

9. NOMINATIONS AND DELIVERY

The quantity of Product to be delivered by Seller and purchased by Buyer in each Contract Year shall, subject to the maximum and minimum annual quantities, be nominated by Buyer on or before the April 15 immediately preceding such Contract Year; provided, however, that the quantity of Product for the first Contract Year shall be nominated at the same time as this Contract is executed. At the same time as Buyer provides Seller with its nomination for a Contract Year, Buyer shall provide Seller with a report (a “**Delivery Schedule**”) that estimates the quantity of Product that it will require to be delivered during each Delivery Period in such Contract Year. Each Delivery Schedule shall be in the form and contain the information set out in Schedule 9 (which shall constitute the Delivery Schedule for this Contract Year commencing May 1, 2008) and shall be used solely for purposes of calculating the Final Price pursuant to Section 16.

On or before the 10th day of each month in each Contract Year, Buyer shall provide Seller with (i) its nomination of the quantity of Product it will require in the month that is two months after the month in which the nomination is being made (provided, however, that nominations for May, June, and July, 2008 shall be made upon signing this Contract), and (ii) one or more five day delivery windows and the estimated ullage at the beginning of each such delivery window. The nominations for each month shall form the basis for Seller's delivery obligations for such month. The aggregate quantity nominated for the months of October, November, December, January, February and March of any Contract Year shall not exceed 300% of the aggregate quantity nominated for the months of April, May, June, July, August and September of such Contract Year. Buyer's nomination for any month shall not be more than 10% higher or lower than the aggregate quantities for such month set out in the Delivery Schedule; provided; however, Buyer shall not be obligated to nominate more than the ullage of its tanks.

Seller agrees to make deliveries each month in quantities sufficient to allow Buyer to drawdown from its tanks the quantity nominated for such month. Provided that Seller always complies with Buyer's requirements as set out in the proceeding sentence, and subject to the availability of berthage, Seller may schedule deliveries when elected by Seller. Buyer shall provide Seller with tank readings on Monday of each week.

10. QUANTITY AND QUALITY MEASUREMENT

Quality shall be determined or witnessed by an international independent inspector chosen by Seller (in accordance with standard practice at the time of delivery) at the discharge port. Quantity shall be determined at the time of delivery per shore measurements, as determined or witnessed by a mutually agreed international independent inspector (in accordance with standard practice at the time of delivery) at the discharge port. The inspectors' reports of quality and quantity shall, save fraud or manifest error, be binding on both parties. All inspection costs at the discharge port shall be for Buyer's account.

11. QUANTITY AND QUALITY CLAIMS TIME BAR

Seller shall in no event be liable for any quantity or quality claim unless the claim has been submitted to Seller in writing with all supporting documentation, within 60 days of the completion of discharge.

12. TERMS OF DELIVERY

Delivered Ex-Ship one safe berth at the Delivery Point. Buyer is the importer of record and responsible for importation.

13. AUTOMATED MANIFEST SYSTEM

(a) Where the discharge port is located within the USA or US Territories. Seller shall advise the vessel of the requirements of the U.S Bureau of Customs and Border Protection ruling issued on December 5th 2003 under Federal Register Part II Department of Homeland Security 19 CFR Parts *4.* 103, and will comply fully with these requirements for entering U.S ports (including far avoidance of doubt, the requirements of the "**Automated Manifest System**").

(b) If the discharge port is changed at Buyer's request such that, despite Seller exercising all reasonable efforts pursuant to Clause (a), Seller's nominated vessel is unable to comply with the notification period required by the U.S Bureau of Customs and Border Protection ruling issued on December 5th 2003 under Federal Register Part II Department of Homeland Security 19 CFR Parts 4, 103 (including for avoidance of doubt, the requirements of the "**Automated Manifest System**"):

(1) any delay directly resulting from such non-compliance shall be for Buyer's account; and

(2) Seller shall not be liable for failure of performance directly resulting from such non- compliance.

14. SELECTION OF VESSELS

The vessel shall be selected by Seller, provided, however, that the vessel shall at ail times meet the requirements of this Contract and any additional requirements of the discharge port.

15. ISMS Compliance

(a) Seller shall assure that the vessel shall comply with the requirements of the International Code for the Security of Ships and of Port Facilities and the relevant amendments to Chapter XI of SOLAS ("**ISPS Code**") and where the discharge port is within the USA and US territories or waters, with the US Maritime Transportation Security Act 2002 ("**MTSA**").

(h) The vessel shall when required submit a Declaration of Security to the appropriate authorities prior to arrival at the discharge port.

(c) If at any time prior to the arrival of the vessel at the discharge port, the vessel ceases to comply with the requirements of the ISPS Code or MTSA:

(1) Buyer shall have the right not to berth such vessel at the discharge port and any demurrage resulting shall not be for the account of the Buyer.

(2) Seller shall be obliged to substitute for such vessel a vessel complying with the requirements of the ISPS Code and MTSA.

(d) Buyer shall assure that the discharge port/terminal/installation shall comply with the requirements of the International Code for the Security of Ships and of Port Facilities and the relevant amendments to Chapter XI of the ISPS Code, and if located within the USA and US territories, with the MTSA.

(e) Any costs or expenses in respect of the vessel including demurrage or any additional charge, fee or duty levied on the vessel at the discharge port and actually incurred by the Seller resulting directly from the failure of the discharge port/terminal/installation to comply with the ISPS Code (and if located within the USA and US territories, with the MTSA) shall, except under the circumstances outline in Section 21(c) below, be for the account of the Buyer, including but not limited to the time required or costs incurred by the vessel in taking any action or any special or additional security measures required by the ISPS Code or MTSA

(f) Save where the vessel has failed to comply with the requirements of the International Code for the Security of Ships and of Port Facilities and the relevant amendments to Chapter XI the ISPS Code, and within the USA and US territories or waters, with the MTSA, the Buyer shall be responsible for any demurrage actually incurred by the Seller arising from delay to the vessel at the discharge port resulting directly from the vessel being required by the port facility or any relevant authority to take any action or any special or additional security measures or undergo additional inspections, by virtue of the vessel’s previous ports of call.

(g) The Buyer’s liability to the Seller under this Contract for any costs, losses or expenses incurred by the vessel, the charterers or the vessel owners resulting from the failure of the discharge port/terminal/ installation to comply with the ISPS Code or MTSA shall be limited to the payment of demurrage and costs actually incurred by the vessel that Seller is obligated to pay in accordance with the provisions of this clause.

16. PRICE

(a) A provisional price for each cargo of Product (the “**Provisional Price**”) shall be calculated by Seller at the time of delivery of the cargo and shall be equal to the quantity of Product in the cargo multiplied by the Provisional Propane Price determined in accordance with Section 16(d)(5). The Provisional Price for a cargo shall be paid within 30 days of the Bill of Lading Date, it being agreed that if the thirtieth day following the day on which delivery commences is not a day on which banks are open in New York, New York, (a "**Banking Day**") such thirty day period shall end on the immediately preceding Banking Day.

In addition to the Provisional Price, if Buyer requests that Seller deliver less than a Standard Shipload (as hereinafter defined), Buyer shall pay a fec of US$0.012 per US gallon for the full volume offloaded at the Delivery Point. No fee shall be payable if a partial shipment is delivered at the direction or request of Seller.

(b) Following payment of the Preliminary Price for a cargo, the final price (the "**Final Price**") for the cargo shall be calculated as follows:

(1) For purposes of calculating the Final Price of a cargo only, Buyer shall be treated as having taken delivery during each Delivery Period of the quantity of Product set out in the then current Delivery Schedule. Such quantities shall be applied to cargos delivered on a first-in, first-out basis, and no quantities shall be treated as having been delivered from a cargo until all cargos with an earlier delivery date are treated as having been fully delivered.

(2) The Final Price for a cargo shall be calculated by Buyer within ten days after the cargo is treated as having been fully delivered by adding together for all Delivery Periods in which Product from such cargo is treated as having been delivered, the product of (i) the quantity of Product treated as having been delivered from such cargo during such Delivery Period, multiplied by (ii) the Delivery Period Propane Price for the Pricing Period which is associated with such Delivery Period, determined in accordance with Section 16(d)(3).

(3) If the Final Price for a cargo is higher than the Provisional Price for such cargo, Buyer shall pay to Seller the additional amount due, and if the Final Price for a cargo is less than the Provisional Price for such cargo, Seller shall refund the overpayment to Buyer, in each case, pursuant to Section 16(c).

(c) Buyer shall submit a written pricing notice to Seller calculating the difference between the Final Price and the Provisional Price for the quantity of Product deemed to have been fully delivered during the Delivery Periods occurring in any month within ten days after the end of such month, and the net amount, if any, owed by Buyer to Seller, or by Seller to Buyer, in respect of such cargo. Any such amounts shall be settled as an addition to or credit against the amount owed by Buyer to Seller on the next invoice submitted by Seller hereunder, and if any such adjustment would reduce the amount of the invoice to less than zero, such amounts shall be carried over to subsequent invoices. If any such amounts are not fully recovered within 90 days from the end of the month to which they relate, or if no further Product is expected to be delivered under this Contract, the Party entitled to the un-recovered amount shall have the right to demand that the other Party pay such amount within ten days.

(d) As used in this Contract:

(1) The "Delivered Price" for any day during a Contract Year shall mean the arithmetic average of the mean of the high and the low price for the Mont Belvieu spot quotations as reported in the OPIS LP Report for TET Propane Any Current Month plus the differential for such Contract Year set out in the table attached hereto as Exhibit "A". The Delivered Price for a Sunday or a Monday on which the OPIS LP Report is not published shall be equal to the Delivered Price for the next succeeding day for which the OPIS LP Report is published, and the Delivered Price for a Saturday or another day other than a Sunday or a Monday on which the OPIS LP Report is not published shall be equal to the Delivered Price for the immediately preceding day on which the OPIS LP Report is published.

(2) The "Delivery Period" shall mean a period which either begins on the first day of a month and ends on the 15th day of such month or begins on the 16th day of a month and end on the last day of such month. Each Contract Year is divided into twenty-four Delivery Periods.

(3) The "Delivery Period Propane Price" for any Delivery Period shall mean the arithmetic average of the Delivered Price for each day during the Pricing Period for such Delivery Period.

(4) The "Pricing Period" with respect to each Delivery Period that begins on the first day of a month, shall mean the period that begins on the 16th day of the immediately preceding month and ends on the last day of the immediately preceding month, and with respect to each Delivery Period that begins on the 16th day of a month, shall mean the period that begins on the first day of such month and ends on the 15th day of such month.

(5) The “Provisional Propane Price” for a cargo shall be the Delivered Price calculated for the day on which Seller commences unloading the Cargo at Buyer’s facility.

17. PAYMENT

Payment shall be made in U.S. Dollars by wire transfer, in full without discount, withholding, setoff or counterclaim, in immediately available funds.

18. PAST DUE PAYMENTS

If any amounts due hereunder remain outstanding for more than five days past the due date thereof, such amounts shall be payable with interest at a rate equal to two percent (2%) above the JP Morgan Chase Bank, New York, N.Y. prime interest rate (or Citibank N.A. New York, New York prime interest rate if JP Morgan Chase Bank interest rate is unknown) in effect on the due date for such payments. Under no circumstances shall this interest be construed as an agreement by Seller to provide extended credit.

18.1 SECURITY

A. Affiliated Security Provisions. So long as Buyer and Seller shall be affiliates, the following security provisions of this Section 18.1 A. alone shall apply:

Should Seller have reasonable grounds for insecurity with respect to the Buyer’s performance of this Contract, Seller shall inform Buyer of such fact in writing and demand adequate assurance of due performance, and until Seller receives such assurance it may, if commercially reasonable, suspend performance for which Seller has not received payment or reciprocal performance. The Parties agree that reasonableness of grounds for insecurity and the adequacy of any assurance offered shall be determined in accordance with applicable commercial standards. After its receipt of a justified written demand, Buyer’s failure to provide (within a reasonable time not exceeding thirty days) such assurance of due performance as is adequate under the circumstances of the particular case is a repudiation of this Contract.

B. Non-Affiliated Security Provisions. Should Buyer and Seller cease to be affiliates during the term of this Contract, the following security provisions of this Sections 18.1 B. shall apply in addition to the provisions of Section 18.1 A. For purposes of this provision, the Buyer and Seller would be deemed “non-affiliated” should there be a significant decline in the level of Spectra Energy Corp direct or indirect ownership interest in DCP Midstream Partners, LP and related subsidiaries (i.e. either a change to less than 50% interest by Spectra Energy Corp in DCP Midstream, LLC or if DCP Midstream, LLC no longer maintains control of the general partner interest in DCP Midstream Partners, LP):

(1) In addition to the provisions of Section 18.1A, Seller may implement the following security provisions if Seller is no longer affiliated with Buyer:

Seller shall establish a maximum open exposure (the "Credit Line") for Buyer taking into consideration Buyer's creditworthiness (or Buyer's guarantor, if applicable). If Buyer's outstanding obligations hereunder exceed at any time the Credit Line extended to Buyer, Seller may request and Buyer at Buyer's option shall within five Banking Days of such request, either (i) establish an irrevocable stand-by letter of credit in a form and for an amount acceptable to Seller issued or confirmed by a first class bank acceptable to Seller, or (ii) prepay in immediately available funds on presentation of Seller's commercial invoice.

(2) Failure by Buyer to provide the required security within five Banking Days of request therefore by Seller shall be considered a material breach of contract. Upon such breach, Seller shall have the right upon written notice to Buyer to terminate this contract without in any way limiting any other remedies available to Seller.

(3) Upon request by Seller, Buyer shall provide Seller with Buyer's and/or Buyer's guarantor's (if applicable) audited annual financial statements or unaudited quarterly financial statements, as the case may be, and any public or private credit ratings by a nationally-recognized credit rating agency as may be available, in order for Seller to determine the financial standing of the Buyer and/or its guarantor (if applicable).

(4) If at any time the financial standing of Buyer (or any guarantor, if applicable) or other person furnishing security in support of Buyer) in Seller's reasonable opinion becomes impaired or unsatisfactory to Seller, Seller shall have the right to reduce the Credit Line that Buyer may have outstanding without providing additional security pursuant to the first paragraph of this Section 18.1 B(1) upon three days' prior written notice to Buyer.

19. BANK ACCOUNT DETAILS

Payment to be made in US Dollars free of all charges without withhold or offset to:

Payments to Seller:

For invoices prior to May 20, 2008:

JP Morgan Chase Bank
ABA No. 021 000021
Account No. *
For Credit to: Spectra Energy Corp
*Portions of this exhibit have been omitted pending a confidential treatment request filed with the Commission

For invoices after May 19, 2008:

JP Morgan Chase Bank
ABA No. 021 000021
Account No. *
For Credit to: Spectra Energy Propane, LLC
*Portions of this exhibit have been omitted pending a confidential treatment request filed with the Commission

Payments to Buyer:

JP Morgan Chase Bank
ABA No. 021 000021
Account No. *
For Credit to: DCP Assets Holding LP
*Portions of this exhibit have been omitted pending a confidential treatment request filed with the Commission

20. WARRANTY OF TITLE

Seller hereby warrants to Buyer that at the time title in the Product delivered under this Contract passes to Buyer, Seller has the right to sell such Product to Buyer and Seller has good, unencumbered and marketable title to such Product.

21. LAYTIME

(a) When the vessel has arrived at the Brenton Reef Pilot Station, or other Coast Guard approved inspection site, and has been cleared by U.S. Coast Guard and is in all respects ready to proceed to Buyer's facility to discharge the product, berth or no berth, the vessel's master or his representative shall tender notice of readiness to Buyer by letter, telegraph, wireless or telephone. If the notice is by telephone, it shall be confirmed in writing within two hours of the telephone call. Vessel laytime allowed to Buyer, without demurrage charges, shall be based on a discharge rate of six hundred metric tons per hour, Saturdays, Sundays and holidays included, plus six hours after receipt of notice of readiness (N.O.R.)

(b) Seller shall arrange for the vessel's master or Seller's agent to notify the Buyer of the E.T.A. 72, 48, and 24 hours in advance of the vessel's arrival at the discharge port. Should the expected arrival hour change following the 48 hour arrival notice, the vessel's master or Seller's agent shall promptly notify the Buyer of the new arrival hour.

(c) None of the following shall count against Buyer's allowed laytime:

(1) Time used in moving the vessel from anchorage to berth;

(2) Time lost due to any delay in the vessel clearing her berth, caused by the vessel;

(3) Time lost if Seller or any agency or authority having jurisdiction over the port or the dock prohibits the discharging of the product at any time unless the prohibition is caused by facility's failure to comply with applicable laws and regulations;

(4) Time lost in awaiting U.S. Coast Guard, Customs and Immigration clearance;

(5) Any time lost or delay caused by port restrictions imposed by any agency or authority having jurisdiction over the port or the dock, such as restrictions relating to tides, dark hours, minimum safety visibility, time waiting for daylight and like conditions; or

(6) Time lost or delay caused by strike, lockout, stoppage or restraint of labor for master, officers and crew of the vessel or tugboat or pilots.

(d) If used laytime exceeds allowed laytime for discharging because of Buyer's inability to receive cargo, then Buyer shall pay for the excess laytime at the demurrage rate per hour.

(e) If, however, demurrage shall be incurred by reason of fire, explosion, storm or by a strike, lockout, stoppage or restraint of labor or by breakdown of machinery or equipment in or about the dock, or in or about Buyer's Facility, the rate of demurrage shall be reduced to one half of the rate for demurrage so incurred.

(f) All charges at the discharge port, other than those defined by Worldscale as being for owners' account (including the expense if any, of shifting berth at the discharge port, unless such shift shall be for the vessels' purposes), shall he paid by Buyer.

22. DEMURRAGE

The demurrage rate shall be calculated in accordance with the Braefoot Bay Assessment for the vessel size used, as such Assessment is in effect on notice of readiness date, and if Braefoot Bay Assessment is unavailable on any day, the Sullom Voe Assessment shall be used instead. Demurrage charges shall be prorated to the number of hours of actual laytirne in excess of allowed laytime.

Seller will promptly invoice Buyer for any claimed demurrage charges, including such documentation as Buyer may reasonably require to verify the calculation of such charges. Buyer will pay all undisputed demurrage charges, without offset, deduction or counterclaim, promptly upon receipt of any invoice from Seller. If Buyer disputes any portion of Seller's demurrage claim, it will promptly notify Seller and the parties will negotiate in good faith to promptly resolve such dispute. Buyer will promptly pay the amount of disputed charges corresponding to the sum agreed between Seller and Buyer.

23. RISK AND TITLE

Title to Product, as well as risk of loss or damage thereto, shall pass from Seller to Buyer as the Product passes the flange between the vessel's cargo discharge manifold and the receiving hose at the Delivery Point. Delivery of the Product shall be deemed to occur when title to and risk of the Product pass to Buyer. Any loss or damage to the Product occurring during the discharge that is caused by or through the fault of the receiving facilities shall be for the account of Buyer. Any loss or damage to the Product occurring during the discharge that is caused through the fault of the vessel shall he for the account of Seller.

24. FORCE MAJEURE AND EXEMPTION FROM RESPONSIBILITY

(a) No Party shall be liable for losses or damages of any kind arising from any delay or partial or total non-compliance with the obligations set forth in this Contract that are caused by an Event of Force Majeure; provided, however, there is no fault or negligence on the part of the claiming Party.

(b) Event of Force Majeure

(1) An “Event of Force Majeure” shall mean any unforeseen or irresistible event that occurs beyond the reasonable control of the Party claiming the Event of Force Majeure and that could not be prevented or overcome by such Party despite its diligence. As a way of example, and provided that such events meet the definition of an Event of Force Majeure as set out in the preceding sentence, the following events (among others) shall constitute Events of Force Majeure: earthquakes, lightning, storms, floods, fires, strikes, factory work stoppages (other than work stoppages involving a Party or an affiliate of a Party), war (for the avoidance of any doubt, the term “war” includes wars which have the impact on the country(ies) of the Parties even their country(ies) is/are not directly involved in such war), state of mobilization, blockades, quarantine restrictions, embargoes, civil disturbances, restrictions imposed by governmental authorities, explosions, lack of electrical power used to make and/or receive the delivery of Product, closing of the ports by the port authorities, and in general any event that would have the direct or indirect effect, either temporary or permanent in nature, of preventing or of creating a particular danger for the extraction, pumping, storage, delivery, or removal of the Product at the loading port. The failure of Seller’s suppliers to deliver Product to Seller shall constitute an Event of Force Majeure to the extent that such failure is excused by an event of force majeure in Seller’s contract with its supplier.

(2) The Party wishing to declare an Event of Force Majeure shall notify the other Party of the Event of Force Majeure provided that reasonable particulars of the events causing such declaration in writing as soon as possible and at no later than three (3) days after the occurrence of the Event of Force Majeure. If an Event of Force Majeure has been declared, and as a result, Seller is unable to deliver all of the quantities of Product that it is obligated to deliver under this Contract, or Buyer is unable to accept delivery of all of the quantities of Product that it is obligated to accept deliver of under this Contract, the Parties shall meet to determine whether (i) the quantity of Product that was to be delivered or accepted under this Contract should be permanently reduced by the quantities that were not delivered because of the Event of Force Majeure, without that having any effect on the remainder of this Contract; or (ii) once the Event of Force Majeure is rectified, the quantities affected by the Event of Force Majeure should be delivered subsequently pursuant to the terms of this Contract. If the Parties are unable to agree, the Party which did not declare the Event of Force Majeure shall be entitled to decide.

(3) The Party declaring the Event of Force Majeure shall use commercially reasonable endeavors to ensure the resumption of normal performance of this Contract at the earliest possible date. If the F.vent of Force Majeure event shall continue for a period in excess of thirty (30) days, the Parties shall meet to discuss the possible solutions to the Event of Force Majeure.

(4) Neither Party shall be entitled to the benefit of the provisions of this Section 25 to the extent its performance is affected by any or all of the following circumstances: (i) economic hardship, to include, without limitation, Seller’s ability to sell Product at a higher or more advantageous price than the Contract Price, Buyer’s ability to purchase Product at a lower or more advantageous price than the Contract Price; (ii) the loss of Buyer’s market(s) or Buyer’s inability to use or resell Product purchased hereunder, except, in either case, as provided in Section 16.1; or (iii) the loss or failure of Seller’s Product supply or depletion of Product stores, except, in either case, as provided in Section 25(b)(1). Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be within the sole discretion of the party experiencing such disturbance.

25. LAW AND DISPUTE RESOLUTION

This Contract shall be interpreted in accordance with, and Seller’s and Buyer’s respective rights and liabilities hereunder shall be determined by, the laws at the time in effect in the State of New York, U.S.A.

Any dispute between the parties regarding interpretation of this Contract, their respective rights and liabilities hereunder, or any other matter arising out of or in connection with this Contract, shall, at the request of either party by notice to the other, be settled by arbitration in New York, New York, to the exclusion of any other forum or jurisdiction, by one Arbitrator, appointed by agreement of the parties. If an agreement is not reached within thirty days of the request either party may apply for an appointment by the Chief Judge of the United States District Court for the Southern District of New York, who shall have power to make the appointment. The arbitration shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association, and the determination of the arbitrator shall be conclusive on the parties and shall include a statement of the reason for the decision.

Unless a Party requests arbitration within two years of the occurrence in dispute, all claims related to the occurrence are barred.

The UN Convention on Contracts for the International Sale of Goods (1980) shall not apply.

26. LIMITATION OF LIABILITY

Neither Seller nor Buyer shall be liable for consequential, indirect or special losses or damage of any kind arising out of or in any way connected with the conclusion, the performance or the termination of this Contract.

27. OTHER TERMS AND CONDITIONS

CONTRACTUAL CONTACT:

NAME: R Paul
TELEPHONE NO: (713) 735-3739
FAX NO: (713) 735-3106

OPERATIONS CONTACT:

NAME: Robert White
TELEPHONE NO. (866) 363-1075
FAX NO: (401) 792-7140

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate by their respective duly authorized officers as of the date first written above.

SPECTRA ENERGY PROPANE LLC	Gas Supply Resources LLC
\s\ William S. Garner	\s\ William Waldheim
Name: William S. Garner	Name: William Waldheim
Title: President	Title: Group Vice President
Date: As of May 1, 2008	Date: June 7, 2008

EXHIBIT "A"
TO
PROPANE SALES CONTRACT BETWEEN
SPECTRA ENERGY PROPANE. LLC, AS SELLER AND
GAS SUPPLY RESOURCES LLC, AS BUYER

Table of Differentials Used to Determine
the Delivered Price for each Contract Year

Contract Year	Differential
1	*
2	*
3	*
4	*
5	*
6	*

* Portions of this exhibit have been omitted pending a confidential treatment request filed with the Commission.

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, 2008;

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 which 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 8, 2008

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

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

I, Scott R. Delmoro, 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, 2008;

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 which 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 8, 2008

/s/ Scott R. Delmoro
Scott R. Delmoro
Vice President & Controller, Chief Accounting Officer
(Principal Accounting 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, 2008, 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 8, 2008

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 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 (18 U.S.C. Section 1350)

The undersigned, the Vice President & Controller, Chief Accounting Officer (Principal Accounting 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, 2008, 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/ Scott R. Delmoro
Scott R. Delmoro
Vice President & Controller, Chief Accounting Officer
(Principal Accounting Officer)
August 8, 2008

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, 2008

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, 2008 (Millions)
ASSETS	
Current assets:	
Cash and cash equivalents	$ 12.3
Short-term investments	1.1
Accounts receivable:	
Trade, net of allowance for doubtful accounts of $0.5 million	56.0
Affiliates	77.0
Inventories	39.3
Unrealized gains on derivative instruments	1.4
Other	39.2
Total current assets	226.3
Restricted investments	221.1
Property, plant and equipment, net	498.8
Goodwill	82.1
Intangible assets, net	28.8
Equity method investments	184.7
Unrealized gains on derivative instruments	2.8
Other long-term assets	1.1
Total assets	$1,245.7
LIABILITIES AND PARTNERS' DEFICIT	
Current liabilities:	
Accounts payable:	
Trade	$ 94.6
Affiliates	37.4
Unrealized losses on derivative instruments	78.5
Accrued interest payable	0.8
Other	16.9
Total current liabilities	228.2
Long-term debt	660.0
Unrealized losses on derivative instruments	218.1
Other long-term liabilities	14.3
Total liabilities	1,120.6
Non-controlling interests	133.4
Commitments and contingent liabilities	
Partners' deficit:	
Partners' equity	174.9
Note receivable from DCP Midstream, LLC	(183.0)
Accumulated other comprehensive loss	(0.2)
Total partners' deficit	(8.3)
Total liabilities and partners' deficit	$1,245.7

See accompanying notes to unaudited condensed consolidated balance sheet.

DCP MIDSTREAM GP, LP
NOTES TO UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEET
AS OF JUNE 30, 2008

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 a 1.3% interest in and act as the general partner for DCP Midstream Partners, LP, or DCP Partners or the partnership, a master limited partnership, 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 (acquired in May 2007); our limited liability company interests in DCP East Texas Holdings, LLC, or East Texas, and Discovery Producer Services LLC, or Discovery (acquired in July 2007); our Wyoming system and a 70% interest in our Colorado system (each acquired in August 2007); our wholesale propane logistics business; and our NGL transportation pipelines.

The condensed consolidated balance sheet has been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The condensed 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 condensed 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 results of operations 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, 2007 included as Exhibit 99.1 to DCP Partners' Form 10-K filed with the Securities and Exchange Commission, or SEC, on March 10, 2008.

2. Summary of Significant Accounting Policies

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

Fair Value Measurements — We measure our derivative financial assets and liabilities related to our commodity derivative activity and our interest rate swaps at fair value as of each balance sheet date. While we utilize as much information as is readily observable in the marketplace in determining fair value, to the extent that information is not available we may use a combination of indirectly observable facts or, in certain instances, may develop our own expectation of the fair value. Calculating the fair value of an instrument is a highly subjective process and involves a significant level of judgment based on our interpretation of a variety of market conditions. The resulting fair value may be significantly different from one measurement date to the next. All realized and unrealized gains and losses, and settlements of commodity derivative instruments are recorded in earnings. All unrealized gains and losses resulting from changes in the fair value of our interest rates swaps are recorded in the condensed consolidated balance sheet within accumulated other comprehensive income, or AOCI.

Accounting for Sales of Units by a Subsidiary — We account 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. As a result, we have deferred approximately $5.4 million of gain on sale of common units in DCP Partners, which is included in other long-term liabilities in the condensed consolidated balance sheet. This gain is related to DCP Partners' equity issuances in June 2007, August 2007 and March 2008. We will recognize this gain in earnings upon conversion of all of DCP Partners' subordinated units to common units.

3. Recent Accounting Pronouncements

***Statement of Financial Accounting Standards, or SFAS, No. 162 "The Hierarchy of Generally Accepted Accounting Principles,"* or SFAS 162** — In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We do not expect the adoption of SFAS 162 to have a significant impact on our consolidated financial position.

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

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

***SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51,"* or SFAS 160 —** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 160 on our financial position.

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

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

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

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;
- establishes a framework for measuring fair value;
- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;

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

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we recorded a cumulative effect transition adjustment of approximately $5.8 million as an increase to earnings and an insignificant amount as an increase to AOCI during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations as of June 30, 2008.

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

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

4. Acquisitions

Gathering and Compression Assets

In August 2007, we acquired certain subsidiaries of Momentum Energy Group, Inc., or MEG, from DCP Midstream, LLC for approximately $165.8 million. As a result of the acquisition, we expanded our operations into the Piceance and Powder River producing basins, thus diversifying our business into new operating areas. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments totaling $10.9 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of borrowings under our credit agreement, along with the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate. The proceeds from this private placement were used to purchase high-grade securities to fully secure our term loan borrowings. These units were registered with the SEC in January 2008.

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

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

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for certain costs incurred and centralized corporate functions performed by DCP Midstream, LLC on our behalf. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, totaling $63.0 million at June 30, 2008, to certain counterparties to our commodity derivative instruments.

Other Agreements and Transactions with DCP Midstream, LLC

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

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 has made capital contributions of $1.6 million to DCP Partners during the six months ended June 30, 2008 as reimbursement for these capital projects.

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, 2008. All interest income earned under the note has been distributed to DCP Midstream, LLC.

In accordance with our partnership agreement, we distribute all available cash to our partners according to their respective ownership interest.

Spectra Energy

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

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

ConocoPhillips

We have multiple agreements whereby we provide a variety of services for ConocoPhillips and its affiliates. The agreements include fee-based and percentage-of-proceeds gathering and processing arrangements, gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received $1.3 million of capital reimbursements during the six months ended June 30, 2008.

Summary of Transactions with Affiliates

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

	June 30, 2008 (Millions)
DCP Midstream, LLC:	
Accounts receivable	$ 72.6
Accounts payable	$ 29.2
Spectra Energy:	
Accounts receivable	$ 0.8
Accounts payable	$ 0.3
ConocoPhillips:	
Accounts receivable	$ 3.6
Accounts payable	$ 7.9

6. Fair Value Measurement

Determination of Fair Value

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

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

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in an inactive (or less active) market for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

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

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 10 Risk Management and Hedging Activities.

Valuation Hierarchy

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

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

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

Commodity Derivative Assets and Liabilities

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

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.

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

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

Interest Rate Derivative Assets and Liabilities

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

Short-Term and Restricted Investments

We are required to post collateral to secure the term loan portion of our credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated tax-exempt debt securities that have stated maturities of 20 years or less, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. Given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper and highly rated tax-exempt debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2.

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

	Total Carrying Value	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)
		(Millions)		
Current assets:				
Short-term investments	$ 1.1	$ —	$ 1.1	$ —
Commodity derivative instruments (a)	$ 1.4	$ —	$ 0.4	$ 1.0
Long-term assets:				
Restricted investments	$ 221.1	$ —	$ 221.1	$ —
Commodity derivative instruments (b)	$ 1.6	$ —	$ —	$ 1.6
Interest rate instruments (b)	$ 1.2	$ —	$ 1.2	$ —
Current liabilities (c):				
Commodity derivative instruments	$ (71.2)	$ —	$ (63.7)	$ (7.5)
Interest rate instruments	$ (7.3)	$ —	$ (7.3)	$ —
Long-term liabilities (d):				
Commodity derivative instruments	$ (212.9)	$ —	$ (205.2)	$ (7.7)
Interest rate instruments	$ (5.2)	$ —	$ (5.2)	$ —

(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, 2007	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, 2008
			(Millions)		
Commodity derivative instruments:					
Current assets	$ 0.2	$ 1.0	$ —	$ (0.2)	$ 1.0
Long-term assets	$ 1.5	$ 0.1	$ —	$ —	$ 1.6
Current liabilities	$ (1.6)	$ (2.7)	$ (5.0)	$ 1.8	$ (7.5)
Long-term liabilities	$ (0.2)	$ (2.9)	$ (4.6)	$ —	$ (7.7)

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

7. Debt

Long-term debt was as follows:

	June 30, 2008
	(Millions)
Revolving credit facility, weighted-average interest rate of 3.19%, due June 21, 2012 (a)	$ 440.0
Term loan facility, interest rate of 2.59%, due June 21, 2012	220.0
Total long-term debt	$ 660.0

(a) $425.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 3.97% to 5.19%, for a net effective rate of 5.16% on the $440.0 million of outstanding debt under our revolving credit facility as of June 30, 2008.

Credit Agreement

We have a 5-year credit agreement, or the Credit Agreement, consisting of a $630.0 million revolving credit facility and a $220.0 million term loan facility. 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, 2008. The unused portion of the revolving credit facility may be used for general corporate purposes and letters of credit. At June 30, 2008, we had $0.3 million of letters of credit outstanding under the Credit Agreement. As of June 30, 2008, the available capacity under our revolving credit facility was $189.7 million.

Other Agreements

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

8. 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 in all of the subordinated units; and (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.

We own a 1.3% general 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, 2008, DCP Partners had outstanding 24,661,754 common units and 3,571,429 subordinated 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 March 2008, DCP Partners 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 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. Therefore, our 2% interest in these distributions was reduced to 1.3%.

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. 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 during the Subordination Period* and *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on our incentive distribution rights.

Subordinated Units — All of the subordinated units are held by DCP Midstream, LLC. DCP Partners' partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to $0.35 per common unit, or the Minimum Quarterly Distribution, plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The subordination period has an early termination provision that permits 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2008 and the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in the partnership agreement are satisfied. DCP Partners determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2008 and, therefore, 50% of the subordinated units converted into common units. DCP Partners' board of directors and the conflicts committee of the board certified that all conditions for early conversion were satisfied. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Distributions of Available Cash during the Subordination Period — DCP Partners' partnership agreement, after adjustment for our relative ownership level, currently 1.3%, requires that DCP Partners make distributions of Available Cash for any quarter during the subordination period in the following manner:

- *first*, to the common unitholders and us as the general partner, in accordance with their pro rata interest, until DCP Partners distributes for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second*, to the common unitholders and us as the general partner, in accordance with their pro rata interest, until DCP Partners distributes for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;
- *third*, to the subordinated unitholders and us as the general partner, in accordance with their pro rata interest, until DCP Partners distributes for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth*, 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 (the First Target Distribution);
- *fifth*, 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 (the Second Target Distribution);
- *sixth*, 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 (the Third Target Distribution); and
- *thereafter*, 48% to us as the general partner, plus our pro rata interest, and the remainder to all unitholders (the Fourth Target Distribution).

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 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 2008:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
May 15, 2008	$ 0.590	$ 19.6
February 14, 2008	0.570	15.7

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

9. Partners' Deficit

At June 30, 2008, partners' deficit consisted of our capital account, AOCI and a note receivable from DCP Midstream, LLC.

As of June 30, 2008, we had a deficit balance of $8.3 million in our partners' deficit account. This negative balance does not represent an asset to us and does not represent obligations by us to contribute cash or other property. The partners' deficit account generally consists of our cumulative share of net income less cash distributions made plus capital contributions made. Cash distributions that we receive during a period from DCP Partners may exceed our interest in DCP Partners' net income for the period. DCP Partners makes quarterly cash distributions of all of its Available Cash, defined above. Future cash distributions that exceed net income and contributions made will result in an increase in the deficit balance in the partners' deficit account.

10. Risk Management and Hedging Activities

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

		June 30, 2008 (Millions)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	$	(0.2)

For the six months ended June 30, 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.

As of June 30, 2008, we had outstanding letters of credit with counterparties to our commodity derivative instruments of $75.0 million. These letters of credit reduce the amount of cash we may be required to post as collateral. As of June 30, 2008, we had cash collateral posted with certain counterparties to our commodity derivative instruments of approximately $39.1 million, which is included in other current assets on the condensed consolidated balance sheet.

Commodity Cash Flow Protection Activities — We use NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGLs, natural gas and condensate. We use the mark-to-market method of accounting for all commodity derivative instruments. As a result, an insignificant amount of the remaining net loss deferred in AOCI at June 30, 2008 is expected to be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings. The changes in fair value of financial derivatives are included in earnings. The agreements are with major financial institutions, which management expects to fully perform under the terms of the agreements.

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

Interest Rate Cash Flow Hedges — We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $425.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheet. Deferred net losses of $0.1 million on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 3.97% to 5.19%, and receive interest payments based on the three-month London Interbank Offered Rate, or LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

11. Commitments and Contingent Liabilities

Litigation — We are a party to various legal proceedings, as well as administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our consolidated financial position. See Note 16 in Exhibit 99.1 of DCP Partners' 2007 Form 10-K for additional details.

Indemnification — DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessor operations. See the "Indemnification" section of Note 5 in Exhibit 99.1 of DCP Partners' 2007 Form 10-K for additional details.

12. Subsequent Events

During the second quarter of 2008, we announced that DCP Midstream, LLC plans to offer to sell its 75% interest in East Texas to us. The closing of this transaction may be deferred beyond our original 2008 target date.

On July 24, 2008, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on August 14, 2008 to unitholders of record on August 7, 2008. This distribution of $0.60 per unit places us in the Fourth Target Distribution level (see Note 8 for discussion of distributions of available cash).

In July 2008, we received a distribution of $8.8 million from Discovery for the second quarter of 2008.

In July 2008, DCP Midstream issued parental guarantees totaling $200.0 million to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We pay DCP Midstream a fee of 0.5% per annum on these outstanding guarantees.

During the third quarter of 2008, we announced plans to invest, along with the partners to our joint venture, approximately $150.0 million over a multi-year period to construct a gathering pipeline to support our Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. Our interest in this pipeline is 70%.

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

During the third quarter of 2008, we announced plans, along with M2 Midstream, LLC, an unaffiliated entity, to pursue development of a natural gas pipeline in northern Louisiana.

Exhibit 99.2

DCP Midstream, LLC
Unaudited Condensed Consolidated Balance Sheet
As of June 30, 2008

DCP MIDSTREAM, LLC
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEET
TABLE OF CONTENTS

DCP MIDSTREAM, LLC
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEET
JUNE 30, 2008
(millions)

ASSETS	
Current assets:	
Cash and cash equivalents	$ 80
Short-term investments	1
Accounts receivable:	
Customers, net of allowance for doubtful accounts of $4 million	1,562
Affiliates	396
Other	93
Inventories	148
Unrealized gains on derivative instruments	588
Other	220
Total current assets	3,088
Property, plant and equipment, net	4,556
Restricted investments	221
Investments in unconsolidated affiliates	203
Intangible assets, net	302
Goodwill	559
Unrealized gains on derivative instruments	218
Other non-current assets	42
Other non-current assets—affiliates	18
Total assets	$9,207
LIABILITIES AND MEMBERS' EQUITY	
Current liabilities:	
Accounts payable:	
Trade	$1,867
Affiliates	107
Other	54
Short-term borrowings	325
Unrealized losses on derivative instruments	725
Distributions payable to members	219
Accrued interest payable	55
Accrued taxes	52
Other	359
Total current liabilities	3,763
Long-term debt	2,961
Unrealized losses on derivative instruments	380
Other long-term liabilities	386
Non-controlling interests	144
Commitments and contingent liabilities	
Members' equity:	
Members' interest	1,582
Accumulated other comprehensive loss	(9)
Total members' equity	1,573
Total liabilities and members' equity	$9,207

See Notes to Unaudited Condensed Consolidated Balance Sheet.

DCP MIDSTREAM, LLC
NOTES TO UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEET
AS OF JUNE 30, 2008

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.

We formed DCP Midstream Partners, LP, a master limited partnership, or DCP Partners, of which our subsidiary, DCP Midstream GP, LP, acts as general partner. As of June 30, 2008 we owned a 28.8% limited partnership interest and a 1.3% 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 have been achieved. As the general partner of DCP Partners, we have responsibility for its operations. Since we exercise control over DCP Partners, 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 for the interim period. Certain information and notes normally included in our annual balance sheet have been condensed in or omitted from the 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, 2007.

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 balance sheet 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.

Fair Value Measurements — We measure our derivative financial assets and liabilities related to our commodity trading activity and our interest rate swaps at fair value as of each balance sheet date. While we utilize as much information as is readily observable in the marketplace in determining fair value, to the extent that information is not available we may use a combination of indirectly observable facts or, in certain instances may develop our own expectation of the fair value. Calculating the fair value of an instrument is a highly subjective process and involves a significant level of judgment based on our interpretation of a variety of market conditions. The resulting fair value may be significantly different from one measurement date to the next. All realized and unrealized gains and losses, and settlements of commodity derivative instruments are recorded in earnings. All unrealized gains and losses resulting from changes in the fair value of our interest rate swaps are recorded in the condensed consolidated balance sheet within accumulated other comprehensive income or loss, or AOCI, or long-term debt.

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. During the six months ended June 30, 2008, we paid distributions of $292 million based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due.

Our board of directors determines the amount of the periodic dividend to be paid to Spectra Energy and ConocoPhillips, by considering net income, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. During the six months ended June 30, 2008, we paid dividends of $820 million to the members, allocated in accordance with their respective ownership percentages.

DCP Partners considers the payment of a quarterly distribution to the holders of its common units and subordinated 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 primarily consists of subordinated units and common units. The subordinated units are entitled to receive the minimum quarterly distribution only after DCP Partners' common unitholders have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in DCP Partners' partnership agreement, have been met. The subordination period has an early termination provision that permitted 50% of the subordinated units, or 3,571,428 units, to convert to common units in February 2008 and permits the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in DCP Partners' partnership agreement are satisfied. During the six months ended June 30, 2008, DCP Partners paid distributions of approximately $21 million to its public unitholders. In addition to our 28.8% limited partnership interests we hold a 1.3% general partnership interest, as well as incentive distribution rights, which entitle us to receive an increasing share of available cash as pre-defined distribution targets have been achieved.

Accounting for Sales of Units by a Subsidiary — We account 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. As a result, we have deferred approximately $270 million of gain on sale of common units in DCP Partners as of June 30, 2008, which is included in other long-term liabilities in the condensed consolidated balance sheet. This gain is comprised of approximately $42 million related to DCP Partners' public offering in March 2008, $36 million related to DCP Partners' private placement in August 2007, $43 million related to DCP Partners' private placement in June 2007, and approximately $149 million related to DCP Partners' initial public offering in December 2005. We will recognize this gain in earnings upon conversion of all of our subordinated units in DCP Partners to common units, which is expected to occur in the first quarter of 2009.

Recent Accounting Pronouncements — ***Statement of Financial Accounting Standards, or SFAS, No. 162 "The Hierarchy of Generally Accepted Accounting Principles,"* or SFAS 162** — In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the Securities and Exchange Commission, or SEC's, approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We do not expect the adoption of SFAS 162 to have a significant impact on our consolidated financial position.

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

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

***SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51,"* or SFAS 160** — In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 160 on our consolidated financial position.

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

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

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

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

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we recorded a cumulative effect transition adjustment of approximately $2 million as an increase to earnings during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations as of June 30, 2008.

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

***FSP of Financial Interpretation, or FIN 39-1, "Amendment of FASB Interpretation No. 39,"* or FSP FIN 39-1** — In April 2008 the FASB issued FSP FIN 39-1, which permits, but does not require, a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN39-1 became effective for us beginning on January 1, 2008; however, we have elected to continue our policy to not offset cash collateral against our derivative asset or liability positions, and will continue to reflect such amounts on a gross basis in our condensed consolidated balance sheet.

2. Acquisitions and Dispositions

Acquisitions

Acquisition of Various Gathering, Pipeline and Compression Assets — On August 29, 2007, we acquired the stock of Momentum Energy Group, Inc., or MEG, for approximately $635 million plus closing adjustments of approximately $11 million. The results of MEG's operations have been included in the condensed consolidated financial statements since that date. As a result of the acquisition, we expanded our operations into the Fort Worth, Piceance and Powder River producing basins, thus diversifying our business into new areas. We funded our portion of this acquisition with a 364-day bridge loan for $450 million, which was paid off in September 2007 with proceeds from the issuance of the $450 million principal amount of 6.75% Senior Notes, as well as cash on hand. See further discussion of this transaction in the Contributions to DCP Partners section below.

Under the purchase method of accounting, the assets and liabilities of MEG were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $138 million, including purchase price adjustments of $3 million during the first quarter of 2008. The goodwill amount recognized relates primarily to projected growth in the Fort Worth and Piceance producing basins due to significant natural gas reserves and high level of drilling activity.

The purchase price allocation is as follows (in millions):

Cash	$ 42
Receivables	23
Other assets	2
Property, plant and equipment	282
Intangible assets	254
Goodwill	138
Payables	(18)
Other liabilities	(34)
Current debt	(20)
Minority interest	(23)
Total allocation of purchase price	$646

In May 2007, DCP Partners acquired certain gathering and compression assets located in southern Oklahoma, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation for approximately $181 million.

In the fourth quarter of 2005, we entered into an agreement to purchase certain pipeline and compressor station assets in Kansas, Oklahoma and Texas for approximately $50 million, which are regulated by the Federal Energy Regulatory Commission, or FERC. We did not receive regulatory approval from the FERC to purchase the assets as non-jurisdictional gathering. We have filed with the FERC and received a certificate to operate the assets as an interstate pipeline. This acquisition is expected to close in 2008.

Contributions to DCP Partners

MEG — Concurrent with our acquisition of the stock of MEG in August 2007, DCP Partners acquired certain subsidiaries of MEG from us for $166 million plus post-closing purchase price adjustments of approximately $9 million. These subsidiaries of MEG own assets in the Piceance Basin, including a 70% operated interest in the Collbran Valley Gas Gathering system joint venture in western Colorado, and assets in the Powder River Basin, including the Douglas gas gathering system in Wyoming. DCP Partners financed this transaction with $120 million of borrowings under DCP Partners' Credit Agreement, the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, DCP Partners issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. These units were registered with the SEC in January 2008. As a result of this transaction, the omnibus agreement with DCP Partners was amended to increase the annual fee payable to us by DCP Partners by $2 million for incremental general and administrative expenses. We will continue to operate these assets and these assets will continue to be included in our financial statements, through the consolidation of DCP Partners.

DCP East Texas Holdings, LLC and Discovery Producer Services LLC — In July 2007, we contributed to DCP Partners our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, and a derivative instrument, for aggregate consideration of $244 million in cash, including $1 million for net working capital and other adjustments, $27 million in common units and $1 million in general partner equivalent units. We own the remaining 75% limited liability company interest in East Texas, while third parties still own the other 60% limited liability interest in Discovery. DCP Partners financed the cash portion of this transaction with borrowings under its existing credit facility. We will continue to operate East Texas and both of these assets will continue to be included in our financial statements, through the consolidation of DCP Partners.

3. Agreements and Transactions with Affiliates

Spectra Energy

Commodity Transactions — We sell a portion of our residue gas and NGLs to, purchase raw 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 other non-current assets—affiliates as of June 30, 2008 are insurance recovery receivables of $18 million and included in accounts receivable—affiliates as of June 30, 2008 are insurance recovery receivables of approximately $1 million.

During the second quarter of 2008, DCP Partners entered into a propane supply agreement with Spectra Energy. The propane supply agreement, effective May 1, 2008 and terminating April 30, 2014, provides DCP Partners propane supply at their marine terminal for up to approximately 120 million gallons of propane annually. This contract replaces the supply that was previously provided under a contract with a third party that was terminated during the first quarter of 2008.

ConocoPhillips

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 raw 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.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase raw natural gas and other petroleum products from, and provide gathering and transportation services 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, 2008
	(millions)
Natural gas held for resale	$ 63
NGLs	85
Total inventories	$ 148

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 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 that we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in an inactive (or less active) market, for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

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

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis, taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 8, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

Valuation Hierarchy

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

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

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

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include 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 by engaging 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 correlation 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 from a higher level within the hierarchy to a lower level 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, and are held with major financial institutions, which are expected to fully perform under the terms of our agreements. The swaps are generally priced based upon a United States Treasury instrument with similar characteristics, adjusted by the credit spread between our company and the United States Treasury instrument. Given that a significant portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified as Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit, our entity valuation, as well as liquidity reserves in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Short-Term and Restricted Investments

We are required to post collateral to secure the term loan portion of DCP Partners' credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated debt securities that have stated maturities of 20 years or less, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. 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 and highly rated debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2.

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

	Total Carrying Value	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)
		(millions)		
Current assets:				
Commodity derivative instruments (a)	$ 586	$ 224	$ 230	$ 132
Interest rate instruments (a)	$ 2	$ —	$ 2	$ —
Short-term investments	$ 1	$ —	$ 1	$ —
Available-for-sale securities (b)	$ 7	$ —	$ 7	$ —
Long-term assets:				
Commodity derivative instruments (c)	$ 210	$ 138	$ 18	$ 54
Interest rate instruments (c)	$ 8	$ —	$ 8	$ —
Restricted investments	$ 221	$ —	$ 221	$ —
Current liabilities (d):				
Commodity derivative instruments	$ (718)	$ (115)	$ (442)	$ (161)
Interest rate instruments	$ (7)	$ —	$ (7)	$ —
Long-term liabilities (e):				
Commodity derivative instruments	$ (375)	$ (38)	$ (284)	$ (53)
Interest rate instruments	$ (5)	$ —	$ (5)	$ —

(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 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, 2007	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, 2008
	(millions)				
Commodity derivative instruments:					
Current assets	$ 125	$ 114	$ (63)	$ (44)	$ 132
Long-term assets	$ 21	$ 33	$ —	$ —	$ 54
Current liabilities	$ (112)	$ (141)	$ 32	$ 60	$ (161)
Long-term liabilities	$ (11)	$ (37)	$ (5)	$ —	$ (53)

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

6. Financing

Long-term debt was as follows:

	June 30, 2008 (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 October 2005, interest at 5.375% payable semiannually, due October 2015	200
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 Partners' credit facility revolver, weighted-average interest rate of 3.19%, due June 2012 (b)	440
DCP Partners' credit facility term loan, interest rate of 2.59%, due June 2012	220
Fair value adjustments related to interest rate swap fair value hedges (a)	8
Unamortized discount	(7)
Long-term debt	$ 2,961

(a) $100 million of debt has been swapped to a floating rate obligation.

(b) $425 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 3.97% to 5.19%, for a net effective rate of 5.16% on the $440 million of outstanding debt under the DCP Partners' revolving credit facility as of June 30, 2008.

Debt Securities — In September 2007, we issued $450 million principal amount of 6.75% Senior Notes due 2037, or the 6.75% Notes, for proceeds of approximately $444 million, net of related offering costs. The 6.75% Notes mature and become due and payable on September 15, 2037. We pay interest semiannually on March 15 and September 15 of each year, and began making payments on March 15, 2008.

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.

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. Any outstanding borrowings under the Facility at maturity may, at our option, be converted to an unsecured one-year term loan. The Facility may be used for letters of credit. As of June 30, 2008, there were no borrowings outstanding under the Facility. As of June 30, 2008, there was $25 million of commercial paper outstanding, which is included in short-term borrowings in the condensed consolidated balance sheet. As of June 30, 2008, there were approximately $8 million in letters of credit outstanding.

In April 2008, we amended the Facility to remove the requirement to maintain a debt to total capitalization ratio of less than or equal to 60% and replaced it with the requirement to maintain a consolidated leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA, in each case as is defined by the Facility) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters following the consummation of asset acquisitions of not more than 5.5 to 1.0.

In April 2008, we entered into a $300 million 364-day credit agreement, which was fully funded in April 2008, matures in April 2009 and is included within short-term borrowings in the condensed consolidated balance sheet. The proceeds were used to partially fund the April 2008 dividend to our parents and bear interest at a rate equal to, at our option and based on our current debt rating, either (1) London Interbank Offered Rate, or LIBOR, plus 0.75% per year or (2) the higher of (a) the Federal Funds Rate in effect on such day plus $^1/_2$ of 1% or (b) the JP Morgan Chase Bank prime rate per year.

On June 21, 2007, DCP Partners entered into the Amended and Restated Credit Agreement, or DCP Partners' Credit Agreement, which replaced their existing credit agreement, which consists of a $630 million revolving credit facility and a $220 million term loan facility. At June 30, 2008, DCP Partners had less than $1 million of letters of credit outstanding under the DCP Partners' Credit Agreement. As of June 30, 2008, the available capacity under the revolving credit facility was approximately $190 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, 2008.

Other Agreements — As of June 30, 2008, DCP Partners had outstanding letters of credit with counterparties to their commodity derivative instruments of $75 million, which reduce the amount of cash DCP Partners may be required to post as collateral. These letters of credit were issued directly by financial institutions and do not reduce the available capacity under DCP Partners' Credit Agreement.

Other Financing — In March 2008, DCP Partners issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of approximately $132 million, net of offering costs.

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

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

	June 30, 2008 (millions)
Commodity derivative instruments:	
Net deferred losses in AOCI	$ (1)
Interest rate derivative instruments:	
Net deferred losses in AOCI	$ (8)
Interest rate fair value hedges:	
Unrealized gains	$ 9

For the six months ended June 30, 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.

Commodity Price Risk — Our principal operations of gathering, processing, compression, transportation and storage of natural gas, and the accompanying operations of fractionation, transportation, gathering, treating, processing, storage and trading and marketing of NGLs create commodity price risk exposure due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts entered into to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs, and related products produced, processed, transported or stored.

Energy Trading (Market) Risk — Certain of our subsidiaries are engaged 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.

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.

Credit Risk — 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 master collateral agreements to mitigate credit exposure. Collateral agreements provide 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 agreements also provide that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, 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, 2008, we held cash deposits of $208 million included in other current liabilities, and $211 million of letters of credit from counterparties, to secure their future performance under financial or physical contracts. We had cash deposits with counterparties of $203 million, of which $39 million was posted by DCP Partners, included in other current assets, to secure our obligations to provide future services or to perform under financial contracts. As of June 30, 2008, DCP Partners also had outstanding letters of credit with counterparties to its commodity derivative instruments of $75 million. These letters of credit reduce the amount of cash DCP Partners may be required to post as collateral. 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.

Commodity Derivative Activity — Our operations of gathering, processing, and transporting natural gas, and the related operations of transporting and marketing of NGL create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGL, natural gas and crude oil.

We manage our commodity derivative activities in accordance with our risk management policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Commodity Cash Flow Protection Activities — DCP Partners uses NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGL, natural gas and condensate. We use the mark-to-market method of accounting for all commodity derivative instruments. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas and petroleum products through December 2011, as the hedged transactions impact earnings. As of June 30, 2008, deferred net losses of less than $1 million are expected to be reclassified into earnings during the next 12 months. The changes in fair value of these financial derivatives are included in earnings. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

As of June 30, 2008, DCP Partners has mitigated a portion of their expected natural gas, NGL and condensate commodity price risk associated with the equity volumes from their gathering and processing operations through 2013 with natural gas, NGL and crude oil derivatives.

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

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 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 physical natural gas, propane or NGLs in future periods.

Commodity Derivatives — Trading and Marketing — Our trading and marketing program is designed to realize margins related to fluctuations in commodity prices and basis differentials, and to maximize the value of certain storage and transportation assets. Certain of our subsidiaries are engaged 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 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 our trading and marketing portfolio with strict policies, which limit exposure to market risk, and require 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.

Interest Rate Cash Flow Hedges — DCP Partners mitigates a portion of their interest rate risk with interest rate swaps, which reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swaps convert the interest rate associated with an aggregate of $425 million of the variable rate exposure to a fixed rate obligation. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheet. As of June 30, 2008, $2 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 3.97% to 5.19% and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

Interest Rate Fair Value Hedges — We have entered into interest rate swaps to convert $100 million of fixed-rate debt securities issued in August 2000 to floating rate debt. These interest rate fair value hedges are at a floating rate based on six-month LIBOR, which is re-priced semiannually through 2030. The swaps meet conditions that permit the assumption of no ineffectiveness. As such, for the life of the swaps no ineffectiveness will be recognized.

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.

In March 2008, after receiving regulatory approval, we finalized settlement of a lawsuit alleging migration of acid gas from a storage formation into a third party producing formation. We obtained the land and the rights to the producing formation. This matter did not have a material adverse effect upon our consolidated financial position.

In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of DCP Midstream GP, LP, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving DCP Partners' Minden processing plant that dates back to August 2000. El Paso claims damages, including interest, in the amount of $6 million in the litigation, the bulk of which stems from audit claims under our commercial contract. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter.

Management 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 financial position.

General Insurance — Midstream's insurance coverage is carried with an affiliate of ConocoPhillips and third party insurers. Midstream's insurance coverage includes: (1) general liability insurance covering third party exposures; (2) statutory workers' compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired vehicles; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of all real and personal property and includes business interruption/extra expense; and (6) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

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 management 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 consolidated financial position.

On July 20, 2006, the State of New Mexico Environment Department issued Compliance Orders to us that list air quality violations during the past five years at three of our owned or operated facilities in New Mexico. The orders allege a number of violations related to excess emissions beginning January 2001, and further require us to install flares for smokeless operations and to use the flares only for emergency purposes. On April 17, 2008, we signed a settlement agreement with the New Mexico Environment Department that resolved all alleged violations through the date of the settlement agreement. Under the terms of the settlement agreement, we paid approximately $2 million in civil penalties and agreed to fund $59 million in facility upgrades at three of our gas plants through April 2011.

9. Guarantees and Indemnifications

We periodically enter into agreements for the acquisition or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, or other liabilities related to the assets being acquired or divested. Claims may be made by third parties under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to five years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities.

10. Subsequent Events

On July 24, 2008, the board of directors of DCP Partners' general partner declared a quarterly distribution of $0.60 per unit, payable on August 14, 2008 to unitholders of record on August 7, 2008.

In July 2008, we issued $200 million of guarantees to certain counterparties to DCP Partners' commodity derivative instruments, to reduce DCP Partners' collateral requirements. DCP Partners pays us a fee of 0.5% per annum on guarantees outstanding.

During the third quarter of 2008, DCP Partners announced plans to invest approximately $150 million over a multi-year period to construct a gathering pipeline to support their Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado.

During the third quarter of 2008, we announced plans, along with DCP Midstream Partners, to invest approximately $56 million in East Texas to construct a gathering pipeline to support the East Texas system.

During the third quarter of 2008, DCP Partners announced plans, along with M2 Midstream, LLC, an unaffiliated entity, to pursue development of a natural gas pipeline in northern Louisiana.