DCP Midstream Partners, LP
Form 10-Q
August 08, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2012

or

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

For the transition period from to

Commission File Number: 001-32678

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	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 x

As of August 3, 2012, there were outstanding 58,620,541 common units representing limited partner interests.

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DCP MIDSTREAM PARTNERS, LP

FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2012

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GLOSSARY OF TERMS

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

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

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in Item 1A. Risk Factors in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2011, as well as the following risks and uncertainties:

- the extent of changes in commodity prices and the demand for our products and services, 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 and producers access to capital on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;

- general economic, market and business conditions;

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

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

- our ability to access the debt and equity markets and the resulting cost of capital, which will depend on general market conditions, our financial and operating results, inflation rates, interest rates and our ability to effectively limit a portion of the adverse effects of potential changes in interest rates by entering into derivative financial instruments, our ability to comply with the covenants in our loan agreements and our debt securities, as well as our ability to maintain our credit ratings;

- the demand for NGL products by the petrochemical, refining or other industries;

- our ability to purchase propane from our suppliers and make associated profitable sales transactions for our wholesale propane logistics business;

- our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required construction, 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 materials;

- the creditworthiness of counterparties to our transactions;

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

- new, additions to and changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment, including climate change legislation and hydraulic fracturing regulations, or the increased regulation of our industry, and their impact on producers and customers served by our systems;

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

- industry changes, including the impact of consolidations, alternative energy sources, technological advances and changes in competition; and

- the amount of collateral we may be required to post from time to time in our transactions, including changes resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act.

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. The forward-looking statements in this report speak as of the filing date of this report. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2012	December 31, 2011
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5.5	$ 7.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.4 million and $0.3 million, respectively	55.9	108.6
Affiliates	63.9	106.2
Inventories	74.0	87.9
Unrealized gains on derivative instruments	53.9	41.2
Other	1.5	2.2
Total current assets	254.7	353.7
Property, plant and equipment, net	1,578.7	1,499.4
Goodwill	153.8	153.8
Intangible assets, net	141.1	145.3
Investments in unconsolidated affiliates	147.1	107.1
Unrealized gains on derivative instruments	43.8	6.4
Other long-term assets	14.3	11.7
Total assets	$ 2,333.5	$ 2,277.4
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 133.6	$ 231.7
Affiliates	6.7	46.8
Unrealized losses on derivative instruments	31.9	59.9
Other	54.3	42.1
Total current liabilities	226.5	380.5
Long-term debt	948.3	746.8
Unrealized losses on derivative instruments	16.6	32.8
Other long-term liabilities	22.5	19.0
Total liabilities	1,213.9	1,179.1
Commitments and contingent liabilities		
Equity:		
Predecessor equity		257.4
Common unitholders (52,094,641 and 44,848,703 units issued and outstanding, respectively)	1,103.3	654.4

General partner	(1.7)	(4.7)
Accumulated other comprehensive loss	(16.8)	(21.2)
Total partners equity	1,084.8	885.9
Noncontrolling interests	34.8	212.4
Total equity	1,119.6	1,098.3
Total liabilities and equity	$ 2,333.5	$ 2,277.4

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 125.4	$ 215.7	$ 395.9	$ 573.9
Sales of natural gas, propane, NGLs and condensate to affiliates	171.1	305.8	387.7	582.7
Transportation, processing and other	33.5	32.3	66.3	66.1
Transportation, processing and other to affiliates	8.4	8.1	19.4	13.3
Gains (losses) from commodity derivative activity, net	37.1	14.0	28.1	(25.1)
Gains (losses) from commodity derivative activity, net affiliates	38.2	(0.3)	41.9	(1.4)
Total operating revenues	413.7	575.6	939.3	1,209.5
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	218.9	369.0	513.1	778.3
Purchases of natural gas, propane and NGLs from affiliates	55.3	84.2	192.3	237.0
Operating and maintenance expense	29.7	26.0	56.0	54.6
Depreciation and amortization expense	9.6	24.7	34.8	49.0
General and administrative expense	3.6	4.1	8.2	8.5
General and administrative expense affiliates	7.4	7.4	14.7	14.7
Other income	(0.2)	(0.1)	(0.3)	(0.2)
Total operating costs and expenses	324.3	515.3	818.8	1,141.9
Operating income	89.4	60.3	120.5	67.6
Interest expense	(11.1)	(8.4)	(23.7)	(16.4)
Earnings from unconsolidated affiliates	2.0	5.7	7.7	10.2
Income before income taxes	80.3	57.6	104.5	61.4
Income tax expense	(0.5)	(0.2)	(0.7)	(0.5)
Net income	79.8	57.4	103.8	60.9
Net income attributable to noncontrolling interests	(0.7)	(9.7)	(1.4)	(13.2)
Net income attributable to partners	79.1	47.7	102.4	47.7
Net loss (income) attributable to predecessor operations		(6.2)	(2.6)	(12.1)
General partner s interest in net income	(10.2)	(6.2)	(18.6)	(11.7)
Net income allocable to limited partners	$ 68.9	$ 35.3	$ 81.2	$ 23.9
Net income per limited partner unit basic	$ 1.33	$ 0.80	$ 1.64	$ 0.56
Net income per limited partner unit diluted	$ 1.33	$ 0.80	$ 1.64	$ 0.56
Weighted-average limited partner units outstanding basic	51.9	44.1	49.4	42.7
Weighted-average limited partner units outstanding diluted	51.9	44.2	49.4	42.7

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Millions)			
Net income	$ 79.8	$ 57.4	$ 103.8	$ 60.9
Other comprehensive income (loss):				
Reclassification of cash flow hedge losses into earnings	4.0	5.1	9.3	10.4
Net unrealized losses on cash flow hedges	(1.6)	(3.4)	(0.7)	(4.3)
Net unrealized losses on cash flow hedges - predecessor		(0.4)	(0.6)	(0.4)
Total other comprehensive income	2.4	1.3	8.0	5.7
Total comprehensive income	82.2	58.7	111.8	66.6
Total comprehensive income attributable to noncontrolling interests	(0.7)	(9.7)	(1.4)	(13.2)
Total comprehensive income attributable to partners	$ 81.5	$ 49.0	$ 110.4	$ 53.4

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, 2012	2011
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 103.8	$ 60.9
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	34.8	49.0
Earnings from unconsolidated affiliates	(7.7)	(10.2)
Distributions from unconsolidated affiliates	8.4	11.9
Net unrealized (gains) losses on derivative instruments	(41.4)	13.1
Other, net	0.6	(6.1)
Change in operating assets and liabilities, which provided (used) cash net of effects of acquisitions:		
Accounts receivable	94.9	43.7
Inventories	13.9	7.1
Accounts payable	(139.1)	(40.4)
Accrued interest	5.1	0.1
Other current assets and liabilities	(0.9)	(20.0)
Other long-term assets and liabilities	(0.8)	(2.8)
Net cash provided by operating activities	71.6	106.3
INVESTING ACTIVITIES:		
Capital expenditures	(99.8)	(68.4)
Acquisitions, net of cash acquired	(291.6)	(37.2)
Acquisition of unconsolidated affiliate		(114.3)
Investments in unconsolidated affiliates	(42.4)	(2.8)
Return of investment from unconsolidated affiliate	1.0	1.6
Proceeds from sale of assets	0.1	0.2
Net cash used in investing activities	(432.7)	(220.9)
FINANCING ACTIVITIES:		
Proceeds from debt	1,008.4	716.0
Payments of debt	(807.0)	(653.0)
Payment of deferred financing costs	(3.2)	(0.1)
Excess purchase price over acquired assets		(35.7)
Proceeds from issuance of common units, net of offering costs	248.0	139.4
Net change in advances to predecessor from DCP Midstream, LLC	(11.5)	17.8
Distributions to unitholders and general partner	(79.4)	(63.4)
Distributions to noncontrolling interests	(3.2)	(15.8)
Contributions from DCP Midstream, LLC	6.9	5.6
Net cash provided by financing activities	359.0	110.8
Net change in cash and cash equivalents	(2.1)	(3.8)
Cash and cash equivalents, beginning of period	7.6	6.7

Cash and cash equivalents, end of period	$	5.5	$	2.9

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Unaudited)

		Partners Equity				
	Predecessor Equity	Common Unitholders	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
			(Millions)			
Balance, January 1, 2012	$ 257.4	$ 654.4	$ (4.7)	$ (21.2)	$ 212.4	$ 1,098.3
Net change in parent advances	(11.5)					(11.5)
Acquisition of additional 66.67% interest in Southeast Texas and NGL Hedge	(247.9)	39.5				(208.4)
Acquisition of additional 49.9% interest in East Texas					(175.8)	(175.8)
Issuance of units for Southeast Texas		48.0				48.0
Issuance of units for East Texas		33.0				33.0
Deficit purchase price under carrying value of acquired net assets		56.5		(4.2)		52.3
Issuance of 5,487,300 common units		248.0				248.0
Equity-based compensation		(0.4)				(0.4)
Distributions to unitholders and general partner		(63.8)	(15.6)			(79.4)
Distributions to noncontrolling interests					(3.2)	(3.2)
Contributions from DCP Midstream, LLC		6.9				6.9
Comprehensive income:						
Net income attributable to predecessor operations	2.6					2.6
Net income		81.2	18.6		1.4	101.2
Reclassification of cash flow hedges into earnings				9.3		9.3
Net unrealized losses on cash flow hedges	(0.6)			(0.7)		(1.3)
Total comprehensive income	2.0	81.2	18.6	8.6	1.4	111.8
Balance, June 30, 2012	$	$ 1,103.3	$ (1.7)	$ (16.8)	$ 34.8	$ 1,119.6

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Unaudited)

		Partners Equity				
	Predecessor Equity	Common Unitholders	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
			(Millions)			
Balance, January 1, 2011	$ 337.8	$ 552.2	$ (6.4)	$ (27.7)	$ 220.1	$ 1,076.0
Net change in parent advances	22.2					22.2
Acquisition of Southeast Texas	(114.3)					(114.3)
Excess purchase price over acquired assets		(34.8)		(0.9)		(35.7)
Issuance of 3,596,636 common units		139.7				139.7
Equity-based compensation		2.3				2.3
Distributions to DCP Midstream, LLC		(2.6)				(2.6)
Distributions to unitholders and general partner		(52.5)	(10.9)			(63.4)
Distributions to noncontrolling interests					(15.8)	(15.8)
Contributions from DCP Midstream, LLC					5.6	5.6
Comprehensive income:						
Net income attributable to predecessor operations	12.1					12.1
Net income		23.9	11.7		13.2	48.8
Reclassification of cash flow hedges into earnings				10.4		10.4
Net unrealized losses on cash flow hedges	(0.4)			(4.3)		(4.7)
Total comprehensive income	11.7	23.9	11.7	6.1	13.2	66.6
Balance, June 30, 2011	$ 257.4	$ 628.2	$ (5.6)	$ (22.5)	$ 223.1	$ 1,080.6

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Description of Business and Basis of Presentation

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

We are a Delaware limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our natural gas services business (which includes our Northern Louisiana system; our Southern Oklahoma system; our 40% interest in Discovery Producer Services LLC, or Discovery; our Wyoming system; a 75% interest in Collbran Valley Gas Gathering, LLC, or Collbran or our Colorado system; our East Texas system (of which 49.9% was acquired in January 2012); our Michigan system; our Southeast Texas system (of which 33.33% and 66.67% were acquired in January 2011 and March 2012, respectively), our NGL logistics business (which includes the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, our 10% interest in the Texas Express NGL pipeline, the NGL storage facility in Michigan and the DJ Basin NGL Fractionators in Colorado), and our wholesale propane logistics business.

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, and is wholly-owned by DCP Midstream, LLC. Prior to May 2012, DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, was owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. Effective May 2012, ConocoPhillips 50% ownership interest in DCP Midstream, LLC has been transferred to the new downstream company, Phillips 66. We do not anticipate that the change in ownership will have a material impact on our business or operations. 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 most of our assets. DCP Midstream, LLC owns approximately 26% of us.

The condensed consolidated financial statements include the accounts of the Partnership and all majority-owned subsidiaries in which we have the ability to exercise control. Investments in greater than 20% owned affiliates that are not variable interest entities and in which we do not have the ability to exercise control, and investments in less than 20% owned affiliates in which we have the ability to exercise significant influence, are accounted for using the equity method. All intercompany balances and transactions have been eliminated.

Our predecessor operations consist of our initial 33.33% interest in Southeast Texas, which we acquired from DCP Midstream, LLC in January 2011, and the remaining 66.67% interest in Southeast Texas and commodity derivative instruments related to the Southeast Texas storage business, which we acquired from DCP Midstream, LLC in March 2012. Prior to our acquisition of the remaining 66.67% interest in Southeast Texas, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method. Subsequent to this transaction, we own 100% of Southeast Texas which we account for as a consolidated subsidiary. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements include the historical results of our 100% interest in Southeast Texas and the natural gas commodity derivatives associated with the storage business for all periods presented. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC s basis in the net assets contributed. The amount of the purchase price in excess or in deficit of DCP Midstream, LLC s basis in the net assets is recognized as a reduction or an addition to partners equity. The 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.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. 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. All 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 adjustments, consisting only of 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. Results of operations for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. 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 in our 2011 Annual Report included as Exhibit 99.3 to our Current Report on Form 8-K filed on June 14, 2012.

2. Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2011-04 Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*, or ASU 2011-04** In May 2011, the FASB issued ASU 2011-04 which amends Accounting Standards Codification, Topic 820 Fair Value Measurements and Disclosures to change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, clarify the FASB s intent about the application of existing fair value measurement requirements, and change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The provisions of ASU 2011-04 became effective for us for interim and annual periods beginning after December 15, 2011. The provisions of ASU 2011-04 impact only disclosures, and we have disclosed information in accordance with the provisions of ASU 2011-04 within this filing.

3. Acquisitions

On April 12, 2012, we acquired a 10% ownership interest in the Texas Express Pipeline joint venture from the operator, Enterprise Products Partners, L.P., or Enterprise, representing an approximate investment of $85.0 million in the joint venture. At closing, we paid $10.9 million for our 10% ownership interest, representing our proportionate share of the investment through the closing date, in the Texas Express Pipeline joint venture and will be responsible for spending an approximate $75.0 million for our share of the remaining construction costs of the pipeline. Originating near Skellytown in Carson County, Texas, the 20-inch diameter Texas Express Pipeline will extend approximately 580 miles to Enterprise s natural gas liquids fractionation and storage complex at Mont Belvieu, Texas, and will provide access to other third party facilities in the area. The Texas Express Pipeline will have an initial capacity of approximately 280 MBbls/d and currently has long-term, fee-based, ship-or-pay transportation commitments of 252 MBbls/d, including a commitment from DCP Midstream, LLC of 20 MBbls/d. The pipeline is expected to be completed by the second quarter of 2013.

On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative instruments related to the Southeast Texas storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. $192.0 million of the aggregate purchase price was financed with a portion of the net proceeds from our 4.95% 10-year Senior Notes offering. The remaining $48.0 million consideration was financed by the issuance at closing of an aggregate of 1,000,417 of our common units to DCP Midstream, LLC. DCP Midstream, LLC also provided fixed price NGL commodity derivatives, valued at $39.5 million, for the three year period subsequent to closing the newly acquired interest. Certain of the NGL commodity derivatives were valued at $24.6

million and represent consideration for the termination of a fee-based storage arrangement we had with DCP Midstream, LLC in conjunction with our initial 33.33% interest in Southeast Texas; the remaining portion of the commodity derivatives, valued at $14.9 million, mitigate a portion of our currently anticipated commodity price risk associated with the gathering and processing portion of the 66.67% interest in Southeast Texas acquired on March 30, 2012. The $29.6 million deficit purchase price under the historical basis of the net assets acquired and the $48.0 million of common units issued as consideration for this acquisition were recorded as an increase in common unitholders equity. Prior to the acquisition of the additional interest in Southeast Texas, we owned a 33.33% interest which we accounted for as an unconsolidated affiliate using the equity method.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The acquisition of the remaining 66.67% interest in Southeast Texas represents a transaction between entities under common control and a change in reporting entity. Accordingly, our consolidated financial statements have been adjusted to retrospectively include the historical results of our 100% interest in Southeast Texas and the natural gas commodity derivatives associated with the storage business for all periods presented, similar to the pooling method.

Combined Financial Information

The results of our 100% interest in Southeast Texas are included in the condensed consolidated balance sheets as of June 30, 2012 and December 31, 2011. The following table presents the previously reported December 31, 2011 condensed consolidated balance sheet, adjusted for the acquisition of the remaining 66.67% interest in Southeast Texas from DCP Midstream, LLC:

As of December 31, 2011

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate Southeast Texas (b)	Remove Southeast Texas Investment in Unconsolidated Affiliate (c)	Combined DCP Midstream Partners, LP (As currently reported)
		(Millions)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 6.7	$ 0.9	$	$ 7.6
Accounts receivable	161.4	53.4		214.8
Inventories	64.7	23.2		87.9
Other	7.1	36.3		43.4
Total current assets	239.9	113.8		353.7
Property, plant and equipment, net	1,181.8	317.6		1,499.4
Goodwill and intangible assets, net	255.8	43.3		299.1
Investments in unconsolidated affiliates	208.7		(101.6)	107.1
Other non-current assets	17.4	0.7		18.1
Total assets	$ 1,903.6	$ 475.4	$ (101.6)	$ 2,277.4

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

LIABILITIES AND EQUITY				
Accounts payable and other current liabilities	$ 269.2	$ 111.3	$	$ 380.5
Long-term debt	746.8			746.8
Other long-term liabilities	46.7	5.1		51.8
Total liabilities	1,062.7	116.4		1,179.1
Commitments and contingent liabilities				
Equity:				
Partners equity				
Net equity	649.7	360.8	(103.4)	907.1
Accumulated other comprehensive loss	(21.2)	(1.8)	1.8	(21.2)
Total partners equity	628.5	359.0	(101.6)	885.9
Noncontrolling interests	212.4			212.4
Total equity	840.9	359.0	(101.6)	1,098.3
Total liabilities and equity	$ 1,903.6	$ 475.4	$ (101.6)	$ 2,277.4

(a) Amounts as previously reported with 33.33% of Southeast Texas results presented as investments in unconsolidated affiliates.
(b) Adjustments to present Southeast Texas on a consolidated basis at 100% ownership, including commodity derivatives.
(c) Adjustments to remove Southeast Texas 33.33% investment in unconsolidated affiliates.

The results of our 100% interest in Southeast Texas are included in the condensed consolidated statements of operations for the three and six months ended June 30, 2012 and 2011. The following table presents the previously reported condensed consolidated statements of operations for the three and six months ended June 30, 2011, adjusted for the acquisition of the remaining 66.67% interest in Southeast Texas from DCP Midstream, LLC:

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Three Months Ended June 30, 2011

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate Southeast Texas (b)	Remove Southeast Texas Equity Earnings (c)	Combined DCP Midstream Partners, LP (As currently reported)
		(Millions)		
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 323.1	$ 198.4	$	$ 521.5
Transportation, processing and other	38.5	1.9		40.4
Gains from commodity derivative activity, net	12.6	1.1		13.7
Total operating revenues	374.2	201.4		575.6
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	274.3	178.9		453.2
Operating and maintenance expense	21.7	4.3		26.0
Depreciation and amortization expense	20.1	4.6		24.7
General and administrative expense	8.6	2.9		11.5
Other income	(0.1)			(0.1)
Total operating costs and expenses	324.6	190.7		515.3
Operating income	49.6	10.7		60.3
Interest expense, net	(8.4)			(8.4)
Earnings from unconsolidated affiliates	10.0		(4.3)	5.7
Income before income taxes	51.2	10.7	(4.3)	57.6
Income tax expense		(0.2)		(0.2)
Net income	51.2	10.5	(4.3)	57.4
Net income attributable to noncontrolling interests	(9.7)			(9.7)
Net income attributable to partners	$ 41.5	$ 10.5	$ (4.3)	$ 47.7

(a) Amounts as previously reported with 33.33% of Southeast Texas results presented as earnings from unconsolidated affiliates.
(b) Adjustments to present Southeast Texas on a consolidated basis at 100% ownership, including commodity derivatives.
(c) Adjustments to remove Southeast Texas equity earnings at 33.33%.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Six Months Ended June 30, 2011

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate Southeast Texas (b)	Remove Southeast Texas Equity Earnings (c)	Combined DCP Midstream Partners, LP (As currently reported)
			(Millions)	
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 752.8	$ 403.8	$	$ 1,156.6
Transportation, processing and other	74.1	5.3		79.4
(Losses) gains from commodity derivative activity, net	(27.6)	1.1		(26.5)
Total operating revenues	799.3	410.2		1,209.5
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	649.3	366.0		1,015.3
Operating and maintenance expense	45.8	8.8		54.6
Depreciation and amortization expense	40.0	9.0		49.0
General and administrative expense	17.6	5.6		23.2
Other income	(0.2)			(0.2)
Total operating costs and expenses	752.5	389.4		1,141.9
Operating income	46.8	20.8		67.6
Interest expense, net	(16.4)			(16.4)
Earnings from unconsolidated affiliates	18.6		(8.4)	10.2
Income before income taxes	49.0	20.8	(8.4)	61.4
Income tax expense	(0.2)	(0.3)		(0.5)
Net income	48.8	20.5	(8.4)	60.9
Net income attributable to noncontrolling interests	(13.2)			(13.2)
Net income attributable to partners	$ 35.6	$ 20.5	$ (8.4)	$ 47.7

(a) Amounts as previously reported with 33.33% of Southeast Texas results presented as earnings from unconsolidated affiliates.
(b) Adjustments to present Southeast Texas on a consolidated basis at 100% ownership, including commodity derivatives.
(c) Adjustments to remove Southeast Texas equity earnings at 33.33%.

The currently reported results are not intended to reflect actual results that would have occurred if the acquired business had been combined during the period presented, nor is it intended to be indicative of the results of operations that may be achieved by us in the future.

On January 3, 2012, we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC for consideration of $165.0 million, less $2.5 million in working capital and other customary purchase price adjustments, for a net purchase price of $162.5 million. $132.0 million of the consideration was financed with proceeds from our January 3, 2012 Term Loan Agreement. The remaining $33.0 million consideration was financed by the issuance at closing of an aggregate of 727,520 of our common units to DCP Midstream, LLC. The $22.7 million deficit purchase price under the historical basis of the net assets acquired and the $33.0 million of common units issued as consideration for this acquisition were recorded as an increase in common unitholders equity. Prior to the contribution of the additional interest in East Texas, we owned a 50.1% interest which we accounted for as a consolidated subsidiary. The contribution of the remaining 49.9% interest in East Texas represents a transaction between entities under common control, but does not represent a change in reporting entity. Accordingly, we have included the results of the remaining 49.9% interest in East Texas prospectively from the date of contribution.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Omnibus Agreement and Other General and Administrative Charges

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. In January 2012, in conjunction with our acquisition of the remaining 49.9% interest in East Texas, we increased the annual fee we pay to DCP Midstream, LLC by $7.4 million. In March 2012, in conjunction with our acquisition of the remaining 66.67% interest in Southeast Texas, we increased the annual fee we pay to DCP Midstream, LLC by $10.3 million, prorated for the remainder of the calendar year. These fees were previously allocated to East Texas and Southeast Texas. As a result of these transactions, the annual fee we pay to DCP Midstream, LLC will be $27.9 million.

Following is a summary of the fees we incurred under the Omnibus Agreement as well as other fees paid to DCP Midstream, LLC:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(Millions)			
Omnibus Agreement	$ 7.0	$ 2.5	$ 11.4	$ 5.0
Other fees DCP Midstream, LLC	0.4	4.8	3.2	9.5
Total DCP Midstream, LLC	$ 7.4	$ 7.3	$ 14.6	$ 14.5

In addition to the Omnibus Agreement, we incurred other general and administrative fees with DCP Midstream, LLC of $0.4 million and $0.4 million, for the three months ended June 30, 2012 and 2011, respectively, and $0.7 million and $0.7 million for the six months ended June 30, 2012 and 2011, respectively. These amounts include allocated expenses, including professional services, insurance and internal audit. For the six months ended June 30, 2012, Southeast Texas incurred $2.5 million in general and administrative expenses directly from DCP Midstream, LLC, before the addition of Southeast Texas to the Omnibus Agreement in March 2012. For the three and six months ended June 30, 2011, Southeast Texas incurred $2.5 million and $5.0 million, respectively, in general and administrative expenses directly from DCP Midstream, LLC. For the three and six months ended June 30, 2011, East Texas incurred $1.9 million and $3.8 million, respectively, in general and administrative expenses directly from DCP Midstream, LLC.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC was a significant customer during the three and six months ended June 30, 2012 and 2011.

We sell a portion of our residue gas, NGLs and condensate to, purchase natural gas and other petroleum products from, and provide gathering and transportation services for, DCP Midstream, LLC. We anticipate continuing to purchase from and sell commodities and services to DCP Midstream, LLC in the ordinary course of business. In addition, DCP Midstream, LLC conducts derivative activities on our behalf. We have and may continue to enter into market based derivative transactions directly with DCP Midstream, LLC, whereby DCP Midstream is the counterparty.

We have a contractual arrangement with DCP Midstream, LLC, through March 2022, in which we pay DCP Midstream, LLC a fee for processing services associated with the gas we gather on our Southern Oklahoma system, which is part of our Natural Gas Services segment. In addition, in February 2010, a contract was signed with DCP Midstream, LLC providing for adjustments to those fees based upon plant efficiencies related to our portion of volumes from the Southern Oklahoma system being processed at DCP Midstream, LLC s plant through March 2022. We generally report fees associated with these activities in the condensed consolidated statements of operations as purchases of natural gas, propane, NGLs and condensate from affiliates. In addition, as part of this arrangement, DCP Midstream, LLC pays us a fee for certain gathering services. We generally report revenues associated with these activities in the condensed consolidated statements of operations as transportation, processing and other to affiliates.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system, included in our Northern Louisiana system, which is part of our Natural Gas Services segment, that are periodically used for the benefit of Pelico. DCP Midstream, LLC is able to source natural gas upstream of Pelico and deliver it to us and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. We purchase natural gas from DCP Midstream, LLC upstream of Pelico and transport it to Pelico under an interruptible transportation agreement with an affiliate. Our purchases from DCP Midstream, LLC are at DCP Midstream, LLC s actual acquisition cost plus any transportation service charges. Volumes that exceed our on-system demand are sold to DCP Midstream, LLC at an index-based price, less contractually agreed to marketing fees. Revenues associated with these activities are reported gross in our condensed consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates.

In conjunction with our acquisitions of our East Texas and Southeast Texas systems, which are part of our Natural Gas Services segment, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on East Texas and Southeast Texas capital projects. These reimbursements are for specific capital projects which have commenced within three years from the respective acquisition dates. DCP Midstream, LLC made capital contributions to East Texas for capital projects of $2.5 million and $2.7 million for the three months ended June 30, 2012 and 2011, respectively, and $5.2 million and $5.6 million for the six months ended June 30, 2012 and 2011, respectively. DCP Midstream, LLC made capital contributions to Southeast Texas for capital projects of $1.7 million for the three months and six months ended June 30, 2012.

In our Natural Gas Services segment, we sell NGLs processed at certain of our plants, and sell condensate removed from the gas gathering systems that deliver to certain of our systems under contracts to a subsidiary of DCP Midstream, LLC equal to that subsidiary s net weighted-average sales price, adjusted for transportation, processing and other charges from the tailgate of the respective asset.

In our NGL Logistics segment, we also have a contractual arrangement with a subsidiary of DCP Midstream, LLC which provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze and Wilbreeze pipelines, pursuant to fee-based rates that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on these pipelines under the transportation agreements. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

With respect to our Wattenberg pipeline, effective January 1, 2011, we entered into a 10-year dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC s processing facilities are dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenues under our tariff. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

We pay a fee to DCP Midstream, LLC to operate our DJ Basin NGL Fractionators and receive fees for the processing of DCP Midstream, LLC s committed NGLs produced by them in Weld County, Colorado at our DJ Basin NGL Fractionators under agreements that are effective through March 2018. We incurred fees of $0.3 million and $0.5 million during the three and six months ended June 30, 2012, respectively, and $0.2 million during the three and six months ended June 30, 2011, which are included in operating and maintenance expense in the consolidated statements of operations.

DCP Midstream, LLC has issued parental guarantees, totaling $50.0 million as of June 30, 2012, in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We pay DCP Midstream, LLC a fee of 0.5% per annum on these outstanding guarantees.

Spectra Energy

We had propane supply agreements with Spectra Energy that terminated April 2012, which provided us propane supply at our marine terminals, included in our Wholesale Propane Logistics segment, for up to approximately 185 million gallons of propane annually.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

ConocoPhillips and Phillips 66

Prior to May 2012, DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, was owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. In May 2012, ConocoPhillips separated its business into two stand-alone publicly traded companies. As a result of this transaction, DCP Midstream, LLC is no longer owned 50% by ConocoPhillips. ConocoPhillips 50% ownership interest in DCP Midstream, LLC has been transferred to the new downstream company, Phillips 66.

We have multiple agreements with Phillips 66 and its affiliates, and anticipate continuing to sell to Phillips 66 and its affiliates in the ordinary course of business. Prior to ConocoPhillips separation in May 2012, these agreements were with ConocoPhillips. We continue to have agreements with ConocoPhillips, including fee-based and percent-of-proceeds gathering and processing arrangements, and gas purchase and gas sales agreements; however, we do not consider ConocoPhillips to be a related party effective May 1, 2012.

Summary of Transactions with Affiliates

The following table summarizes transactions with affiliates:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$ 169.4	$ 286.1	$ 378.6	$ 551.5
Transportation, processing and other	$ 7.9	$ 6.3	$ 17.1	$ 9.5
Purchases of natural gas, propane and NGLs	$ 15.6	$ 35.6	$ 75.5	$ 98.6
Gains losses from commodity derivative activity, net	$ 38.2	$ (0.3)	$ 41.9	$ (1.4)
General and administrative expense	$ 7.4	$ 7.3	$ 14.6	$ 14.5
Spectra Energy:				
Purchases of natural gas, propane and NGLs	$ 39.4	$ 46.5	$ 113.1	$ 131.7
ConocoPhillips (a):				
Sales of natural gas, propane, NGLs and condensate	$ 1.6	$ 19.7	$ 9.0	$ 31.2
Transportation, processing and other	$ 0.5	$ 1.8	$ 2.3	$ 3.8
Purchases of natural gas, propane and NGLs	$ 0.3	$ 2.1	$ 1.3	$ 3.6
General and administrative expense	$	$ 0.1	$ 0.1	$ 0.2
Phillips 66 (a):				
Sales of natural gas, propane, NGLs and condensate	$ 0.1	$	$ 0.1	$
Unconsolidated affiliates:				
Purchases of natural gas, propane and NGLs	$	$	$ 2.4	$ 3.1

(a) In connection with the Phillips 66 separation, ConocoPhillips is not considered to be a related party for periods after April 30, 2012 and Phillips 66 is considered a related party for periods starting May 1, 2012.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

We had balances with affiliates as follows:

		June 30, 2012	December 31, 2011
		(Millions)	
DCP Midstream, LLC:			
Accounts receivable		$ 62.3	$ 100.0
Accounts payable		$ 6.7	$ 22.6
Unrealized gains on derivative instruments	current	$ 49.0	$ 0.6
Unrealized gains on derivative instruments	long-term	$ 35.2	$
Unrealized losses on derivative instruments	current	$ (13.4)	$ (0.6)
Unrealized losses on derivative instruments	long-term	$ (2.5)	$
Spectra Energy:			
Accounts receivable		$	$ 0.1
Accounts payable		$	$ 21.4
ConocoPhillips (a):			
Accounts receivable		$	$ 6.1
Accounts payable		$	$ 0.4
Unrealized gains on derivative instruments	current	$	$ 2.5
Unrealized losses on derivative instruments	current	$	$ (2.0)
Phillips 66 (a):			
Accounts receivable		$ 1.6	$
Unconsolidated affiliates:			
Accounts payable		$	$ 2.4

(a) In connection with the Phillips 66 separation, ConocoPhillips is not considered to be a related party for periods after April 30, 2012 and Phillips 66 is considered a related party for periods starting May 1, 2012.

5. Inventories

Inventories were as follows:

	June 30, 2012	December 31, 2011
	(millions)	
Natural gas	$ 16.5	$ 25.6
NGLs	57.5	62.3
Total inventories	$ 74.0	$ 87.9

We may recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their estimated market value. These non-cash charges are a component of purchases of natural gas, propane and NGLs in the condensed consolidated statements of operations. We recognized $14.5 million and $19.1 million in lower of cost or market adjustments during the three and six months ended June 30, 2012, respectively. We recognized $0.6 million in lower of cost or market adjustments during the six months ended June 30, 2011 and no lower of cost or market adjustments to our natural gas and NGL inventories for the three months ended June 30, 2011.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Property, Plant and Equipment

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

	Depreciable Life	June 30, 2012	December 31, 2011
		(Millions)	
Gathering and transmission systems	20 50 Years	$ 1,261.6	$ 1,211.9
Processing, storage, and terminal facilities	35 60 Years	775.1	742.8
Other	3 30 Years	22.9	23.1
Construction work in progress		246.3	218.3
Property, plant and equipment		2,305.9	2,196.1
Accumulated depreciation		(727.2)	(696.7)
Property, plant and equipment, net		$ 1,578.7	$ 1,499.4

Interest capitalized on construction projects for the three months ended June 30, 2012 and 2011 was $1.8 million and $0.3 million, respectively, and for the six months ended June 30, 2012 and 2011 was $3.0 million and $0.5 million, respectively.

We revised the depreciable lives for our gathering and transmission systems, processing, storage and terminal facilities, and other assets effective April 1, 2012. The key contributing factors to the change in depreciable lives is an increase in the estimated remaining economically recoverable reserves resulting from the development of techniques that improve commodity production in the regions our assets serve. Advances in extraction processes, along with better technology used to locate commodity reserves, is giving producers greater access to unconventional commodities. Based on our property, plant and equipment as of April 1, 2012, the new remaining depreciable lives resulted in an approximate $11.9 million reduction in depreciation expense for the three and six months ended June 30, 2012 and will result in an estimated reduction in depreciation expense of $36.0 million for the year ended December 31, 2012. This change in our estimated depreciable lives increased net income per limited partner unit by $0.23 and $0.24 for the three and six months ended June 30, 2012.

In connection with our evaluation of useful lives, we corrected the classification for certain assets within the presentation of our major classes of property, plant and equipment as of December 31, 2011.

Depreciation expense was $7.5 million and $22.6 million for the three months ended June 30, 2012 and 2011, respectively, and $30.6 million and $44.8 million for the six months ended June 30, 2012 and 2011, respectively.

Asset Retirement Obligations As of June 30, 2012, we had asset retirement obligations of $16.3 million included in other long-term liabilities in the condensed consolidated balance sheets. As of December 31, 2011, we had asset retirement obligations of $12.4 million included in other long-term liabilities in the condensed consolidated balance sheets. During the first quarter of 2012, we recorded a change in estimate to increase our asset retirement obligations by approximately $4.3 million. The change in estimate was primarily attributable to a reassessment of anticipated timing of settlements and of the original asset retirement obligation estimated amounts. For the three months ended June 30, 2012, accretion expense was $0.2 million, and for the six months ended June 30, 2012, accretion benefit was $0.4 million. For the three and six months ended June 30, 2011, accretion expense was $0.1 million and $0.3 million, respectively.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Goodwill and Intangible Assets

The change in the carrying amount of goodwill was as follows:

	Six Months Ended June 30, 2012	Year Ended December 31, 2011
	(Millions)	
Beginning of period	$ 153.8	$ 151.2
Acquisitions		2.6
End of period	$ 153.8	$ 153.8

The carrying value of goodwill as of June 30, 2012 and December 31, 2011 was $82.2 million for each of the periods for our Natural Gas Services segment, $34.7 million for each of the periods for our NGL logistics segment, and $36.9 million for each of the periods for our Wholesale Propane Logistics segment.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and were as follows:

	June 30, 2012	December 31, 2011
	(Millions)	
Gross carrying amount	$ 164.3	$ 164.3
Accumulated amortization	(23.2)	(19.0)
Intangible assets, net	$ 141.1	$ 145.3

We recorded amortization expense of $2.1 million for each of the three months ended June 30, 2012 and 2011, and $4.2 million for each of the six months ended June 30, 2012 and 2011, respectively. As of June 30, 2012, the remaining amortization periods ranged from approximately 10 years to 23 years, with a weighted-average remaining period of approximately 18 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (Millions)
Remainder of 2012	$ 4.2
2013	8.4
2014	8.4
2015	8.4
2016	8.4

Thereafter	103.3
Total	$ 141.1

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of June 30, 2012	December 31, 2011
		(Millions)	
Discovery Producer Services LLC	40%	$ 136.0	$ 106.9
Texas Express Pipeline	10%	10.9	
Other	50%	0.2	0.2
Total investments in unconsolidated affiliates		$ 147.1	$ 107.1

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $31.4 million and $32.6 million at June 30, 2012 and December 31, 2011, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Millions)			
Discovery Producer Services LLC	$ 2.0	$ 5.7	$ 7.7	$ 10.2
Total earnings from unconsolidated affiliates	$ 2.0	$ 5.7	$ 7.7	$ 10.2

The following summarizes combined financial information of our investments in unconsolidated affiliates:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Millions)			
Statements of operations:				
Operating revenue	$ 35.9	$ 52.8	$ 83.1	$ 103.5
Operating expenses	$ 31.8	$ 40.0	$ 66.4	$ 81.0
Net income	$ 3.5	$ 12.8	$ 16.2	$ 22.5

	June 30, 2012	December 31, 2011
	(Millions)	
Balance sheets:		
Current assets	$ 40.3	$ 37.4
Long-term assets	587.8	350.5
Current liabilities	(58.2)	(17.4)
Long-term liabilities	(30.8)	(26.6)
Net assets	$ 539.1	$ 343.9

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If 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. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. 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 as well as any letters of credit that they have provided.

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

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

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

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market 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 11 Risk Management and Hedging Activities.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Valuation Hierarchy

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

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

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

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

A financial instrument s categorization within the hierarchy is based upon the input that requires the highest degree of judgment in the determination of the instrument s fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

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

Within our Natural Gas Services segment we typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. 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 an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Interest Rate Derivative Assets and Liabilities

We use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our existing floating rate debt for fixed-rate debt. Our swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR instrument. Given that a portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit and entity valuation adjustments in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Nonfinancial Assets and Liabilities

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

We utilize fair value on a recurring basis to measure our contingent consideration that is a result of certain acquisitions. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and are classified within Level 3.

The following table presents the financial instruments carried at fair value as of June 30, 2012 and December 31, 2011, by consolidated balance sheet caption and by valuation hierarchy as described above:

	June 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Commodity derivatives (a)	$	$ 10.3	$ 43.6	$ 53.9	$	$ 40.1	$ 1.1	$ 41.2
Long-term assets:								
Commodity derivatives (b)	$	$ 8.3	$ 35.5	$ 43.8	$	$ 5.4	$ 1.0	$ 6.4
Current liabilities (c):								
Commodity derivatives	$	$ (27.5)	$ (0.4)	$ (27.9)	$	$ (43.1)	$ (0.7)	$ (43.8)
Interest rate derivatives	$	$ (4.0)	$	$ (4.0)	$	$ (16.1)	$	$ (16.1)
Long-term liabilities (d):								
Commodity derivatives	$	$ (12.6)	$ (0.3)	$ (12.9)	$	$ (27.5)	$ (0.3)	$ (27.8)
Interest rate derivatives	$	$ (3.7)	$	$ (3.7)	$	$ (5.0)	$	$ (5.0)

(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.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Changes in Levels 1 and 2 Fair Value Measurements

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. 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. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. The determination to classify a financial instrument within Level 1 or Level 2 is based upon the availability of quoted prices for identical or similar assets and liabilities in active markets. Depending upon the information readily observable in the market, and/or the use of identical or similar quoted prices, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period. In the event that there is a movement between the classification of an instrument as Level 1 or 2, the transfer between Level 1 and Level 2 would be reflected in a table as Transfers in/out of Level 1/Level 2. During the six months ended June 30, 2012, there were no transfers between Level 1 and Level 2 of the fair value hierarchy.

Changes in Level 3 Fair Value Measurements

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

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Three months ended June 30, 2012 (a):				
Beginning balance	$ 14.6	$ 27.9	$ (2.6)	$ (0.4)
Net realized and unrealized gains included in earnings (d)	33.8	7.6	3.7	0.1
Transfers into Level 3 (c)				
Transfers out of Level 3 (c)				
Settlements	(4.8)		(1.5)	
Ending balance	$ 43.6	$ 35.5	$ (0.4)	$ (0.3)
Net unrealized gains still held included in earnings (d)	$ 32.2	$ 7.6	$ 1.5	$ 0.1
Three months ended June 30, 2011 (b):				
Beginning balance	$ 0.2	$ 0.2	$ (2.3)	$ (2.4)
Net realized and unrealized gains (losses) included in earnings (d)	0.5	0.1	(1.5)	0.6
Transfers into Level 3 (c)				
Transfers out of Level 3 (c)			1.3	1.5
Settlements	(0.1)		1.3	
Ending balance	$ 0.6	$ 0.3	$ (1.2)	$ (0.3)
Net unrealized gains (losses) still held included in earnings (d)	$ 0.5	$ 0.1	$ (0.2)	$ 0.3

(a) There were no purchases, issuances and sales of derivatives for the three months ended June 30, 2012.
(b) There were no purchases, issuances and sales of derivatives for the three months ended June 30, 2011.
(c) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(d) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Six months ended June 30, 2012 (a):				
Beginning balance	$ 1.1	$ 1.0	$ (0.7)	$ (0.3)
Net realized and unrealized gains included in earnings (d)	30.8	7.8	0.7	
Transfers into Level 3 (c)				
Transfers out of Level 3 (c)				
Settlements	(1.1)		0.3	
Purchases	12.8	26.7	(0.7)	
Ending balance	43.6	35.5	(0.4)	(0.3)
Net unrealized gains still held included in earnings (d)	$ 30.2	$ 7.8	$ 0.5	$
Six months ended June 30, 2011 (b):				
Beginning balance	$ 0.3	$ 0.3	$ (0.1)	$ (0.5)
Net realized and unrealized gains (losses) included in earnings (d)	0.5		(1.2)	(1.2)
Transfers into Level 3 (c)				
Transfers out of Level 3 (c)				1.4
Settlements	(0.2)		0.1	
Ending balance	$ 0.6	$ 0.3	$ (1.2)	$ (0.3)
Net unrealized gains (losses) still held included in earnings (d)	$ 0.5	$	$ (1.2)	$ 0.1

(a) There were no issuances and sales of derivatives for the six months ended June 30, 2012.
(b) There were no purchases, issuances and sales of derivatives for the six months ended June 30, 2011.
(c) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(d) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3.

Quantitative Information and Fair Value Sensitivities Related to Level 3 Unobservable Inputs

We utilize the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

Product Group	Fair Value (Millions)	Forward Curve Range	
Assets			
NGLs	$ 77.1	$ 0.32-$1.83	Per gallon

Natural Gas	$	2.0	$ 3.30-$4.15	Per MMBtu
Liabilities				
NGLs	$		$	Per gallon
Natural Gas	$	(0.7)	$ 3.51-$4.15	Per MMBtu

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Estimated Fair Value of Financial Instruments

Valuation of a contract s fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

The fair value of our interest rate swaps and commodity non-trading derivatives is based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The prices supported by quoted market prices and other external sources category includes our interest rate swaps, our NGL and crude oil swaps, and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes strip transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The prices based on models and other valuation methods category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

We have determined fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on derivative instruments are carried at fair value. Each of the carrying and fair values of outstanding balances under our Credit Agreement are $350.0 million as of June 30, 2012, and $497.0 million as of December 31, 2011. The carrying and fair values of the 4.95% Senior Notes are $350.0 million and $361.0 million, respectively, as of June 30, 2012. The carrying and fair values of the 3.25% Senior Notes are $250.0 million and $253.5 million as of June 30, 2012. The carrying value of the 3.25% Senior Notes as of December 31, 2011 was $250.0 million, which approximated fair value. We determine the fair value of our credit facility borrowings based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We determine the fair value of our fixed-rate debt based on quotes obtained from bond dealers. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

10. Debt

Long-term debt was as follows:

	June 30, 2012	December 31, 2011
	(Millions)	
Credit Agreement		
Revolving credit facility, weighted-average variable interest rate of 1.50% and 1.69%, respectively, and net effective interest rate of 2.66% and 4.86%, respectively, due November 10, 2016 (a)	$ 350.0	$ 497.0
Debt Securities		
Issued March 13, 2012, interest at 4.95% payable semi-annually, due April 1, 2022	350.0	
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250.0	250.0
Unamortized discount	(1.7)	(0.2)
Total long-term debt	$ 948.3	$ 746.8

(a) $150.0 million has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.94% to 2.99%, for a net effective rate of 2.66% on the $350.0 million of outstanding debt under our revolving credit facility as of June 30, 2012.

Credit Agreement

We have a $1.0 billion revolving credit facility that matures November 10, 2016, or the Credit Agreement.

At June 30, 2012 and December 31, 2011, we had $1.1 million of letters of credit issued and outstanding under the Credit Agreement. As of June 30, 2012, the unused capacity under the revolving credit facility was $648.9 million, of which $567.2 million was available for general working capital purposes.

Our borrowing capacity is limited at June 30, 2012 by the Credit Agreement s financial covenant requirements. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the November 10, 2016 maturity date.

Under the Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) LIBOR, plus an applicable margin of 1.25% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A. s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.25% based on our current credit rating. The revolving credit facility incurs an annual facility fee of 0.25% based on our current credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

The Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of certain acquisitions of not more than 5.5 to 1.0.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Debt Securities

On March 13, 2012, we issued $350.0 million of 4.95% 10-year Senior Notes due April 1, 2022. We received proceeds of $345.8 million, which are net of underwriters fees, related expenses and unamortized discounts of $4.2 million, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2012. The notes will mature on April 1, 2022, unless redeemed prior to maturity. The underwriters fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

The notes are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under our Credit Facility. We are not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at our option.

Term Loan Agreement

On January 3, 2012, we entered into a 2-year Term Loan Agreement and borrowed $135.0 million which was used to fund the cash portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

Other Agreements

As of June 30, 2012, we had a contingent letter of credit for up to $10.0 million, on which we pay a fee of 0.50% per annum. This facility reduces the amount of cash we may be required to post as collateral. As of June 30, 2012, we had no letters of credit issued on this facility. Any letters of credit issued on this facility will incur a fee of 1.75% per annum and will not reduce the available capacity under our credit facility. This contingent letter of credit was terminated in July 2012.

The future maturities of long-term debt in the year indicated are as follows:

	Debt Maturities (Millions)
2011	$
2012	
2013	
2014	
2015	250.0
Thereafter	700.0
	950.0
Unamortized discount	(1.7)
Total	$ 948.3

11. Risk Management and Hedging Activities

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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Commodity Price Risk

Cash Flow Protection Activities We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering, processing and storage services, we may receive cash or commodities as payment for these services, depending on the contract type. We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2016 with commodity derivative instruments. Given the limited liquidity and tenor of the NGL derivatives market, we have utilized crude oil swaps and costless collars to mitigate a portion of our commodity price exposure for NGLs. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. Historically, prices of NGLs have been generally related to the price of crude oil, with some exceptions, notably in late 2008 to early 2009, when NGL pricing was at a greater discount to crude oil pricing. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Our crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange our floating price risk for a fixed price. We also utilize crude oil costless collars that minimize our floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that we use to mitigate a portion of our risk may vary depending upon our risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within our consolidated statements of operations as a gain or a loss on commodity derivative activity.

Our Wholesale Propane Logistics segment is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. However, to the extent that we carry propane inventories or our sales and supply arrangements are not aligned, we are exposed to market variables and commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. While the majority of our sales and purchases in this segment are index-based, occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. In such cases, we may manage this risk with derivatives that allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These transactions are not designated as hedging instruments for accounting purposes and any change in fair value is reflected in the current period within our condensed consolidated statements of operations as a gain or loss on commodity derivative activity.

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting, whereby changes in fair value are recorded directly to the condensed consolidated statements of operations; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting.

Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our condensed consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

Commodity Cash Flow Hedges On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative instruments related to the Southeast Texas storage business.

During 2011, Southeast Texas commenced an expansion project to build an additional storage cavern. Upon completion of the expansion project, Southeast Texas will be required to purchase a significant amount of base gas to bring the storage cavern to operation. To mitigate risk associated with this forecasted purchase of natural gas, Southeast Texas executed a series of derivative financial instruments, which have been designated as cash flow hedges. These cash flow hedges were in a loss position of $3.3 million as of June 30, 2012 and will fluctuate in value through the term of construction. Any effective changes in fair value of these derivative instruments will be deferred in AOCI until the underlying purchase of inventory occurs. While the cash paid or received upon settlement of these hedges will economically offset the cash required to purchase the base gas, following completion of the additional storage cavern, any deferred gain or loss at the time of the purchase will remain in AOCI until the cavern is emptied and the base gas is sold.

In order for storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our condensed consolidated balance sheets as a component of property, plant and equipment, net. To mitigate the risk associated with the forecasted re-purchase of base gas, in 2008 we executed a series of derivative financial instruments, which were designated as cash flow hedges. The cash paid upon settlement of these hedges economically offsets the cash paid to purchase the base gas. As a result, a deferred loss of $2.7 million was recognized and will remain in AOCI until such time that our cavern is emptied and the base gas is sold.

Interest Rate Risk

We mitigate a portion of our interest rate risk with interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations.

At December 31, 2011, we had interest rate swap agreements totaling $450.0 million, of which we had designated $425.0 million as cash flow hedges and accounted for the remaining $25.0 million under the mark-to-market method of accounting. In March 2012, we paid down a portion of the revolving credit facility and, as a result, we discontinued cash flow hedge accounting on $225.0 million of our interest rate swap agreements.

At June 30, 2012, we had interest rate swap agreements extending through June 2014 totaling $150.0 million, which are designated as cash flow hedges. Based on our current operations we believe our interest rate swap agreements mitigate our interest rate risk associated with our variable-rate debt.

Effectiveness of our interest rate swap agreements designated as cash flow hedges 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 consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. The effect that these swaps have on our consolidated financial statements, as well as the effect that is expected over the upcoming 12 months is summarized in the charts below. However, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

At June 30, 2012, $150.0 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we pay fixed-rates ranging from 2.94% to 2.99%, and receive interest payments based on the one-month LIBOR.

On March 8, 2012, we settled $195.0 million of our forward-starting interest rate swap agreements for $6.6 million. The remaining net deferred losses of $5.0 million in AOCI will be amortized into interest expense associated with our long-term debt offering through 2022.

Contingent Credit Features

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

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

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

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

- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under those agreements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Credit Agreement. As of June 30, 2012, we are not a party to any agreements that would be subject to these provisions other than our credit agreement.

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

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position. As of June 30, 2012, we had $25.0 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of June 30, 2012, if a credit-risk related event were to occur we may be required to post additional collateral. Although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of June 30, 2012, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $18.5 million.

As of June 30, 2012, we had $150.0 million of individual interest rate swap instruments that were in a net liability position of $7.7 million and were subject to credit-risk related contingent features. If we were to have a default of any of our covenants to our Credit Agreement that occurs and is continuing, the counterparties to our swap instruments have the right to request that we net settle the instrument in the form of cash.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Unconsolidated Affiliates

Discovery Producer Services LLC, our unconsolidated affiliate, entered into agreements with a pipe vendor denominated in a foreign currency in connection with the planned expansion for the natural gas gathering pipeline system in the deepwater Gulf of Mexico, the Keathley Canyon Connector. Discovery entered into certain foreign currency derivative contracts to mitigate a portion of the foreign currency exchange risks which were designated as cash flow hedges. As these hedges are owned by Discovery, an unconsolidated affiliate, we include the impact to AOCI on our consolidated balance sheet.

Collateral

As of June 30, 2012, we had a contingent letter of credit facility for up to $10.0 million, on which we have no letters of credit issued. This contingent letter of credit was terminated in July 2012. DCP Midstream, LLC had issued and outstanding parental guarantees totaling $50.0 million in favor of certain counterparties to our commodity derivative instruments. This contingent letter of credit facility and parental guarantees reduce the amount of cash we may be required to post as collateral. As of June 30, 2012, we had no cash collateral posted with counterparties to our commodity derivative instruments.

Summarized Derivative Information

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

	June 30, 2012	December 31, 2011
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (6.0)	$ (1.8)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(10.3)	(19.4)
Foreign currency cash flow hedges (a):		
Net deferred losses in AOCI	(0.5)	
Total AOCI	$ (16.8)	$ (21.2)

(a) Relates to Discovery, our unconsolidated affiliate.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Balance Sheet Line Item	June 30, 2012	December 31, 2011	Balance Sheet Line Item	June 30, 2012	December 31, 2011
	(Millions)			(Millions)	
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (1.3)	$
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term	(2.0)	(2.6)
	$	$		$ (3.3)	$ (2.6)
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (4.0)	$ (15.7)
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term	(3.7)	(5.0)
	$	$		$ (7.7)	$ (20.7)
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments current	$ 53.9	$ 41.2	Unrealized losses on derivative instruments current	$ (26.6)	$ (43.8)
Unrealized gains on derivative instruments long-term	43.8	6.4	Unrealized losses on derivative instruments long-term	(10.9)	(25.2)
	$ 97.7	$ 47.6		$ (37.5)	$ (69.0)
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$	$ (0.4)
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term		
	$	$		$	$ (0.4)

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

	Gain (Loss) Recognized in AOCI on Derivatives Effective Portion		Loss Reclassified From AOCI to Earnings Effective Portion		Loss Recognized in Income on Derivatives Ineffective Portion and Amount Excluded From Effectiveness Testing		Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	Three Months Ended June 30,						
	2012	2011	2012	2011	2012	2011	
	(Millions)		(Millions)		(Millions)		(Millions)
Interest rate derivatives	$ (0.4)	$ (3.3)	$ (4.0)	$ (5.1)(a)	$	$ (a)	$ (2.7)
Commodity derivatives	$ 0.2	$ (0.1)	$	$	$ (0.1)	$ (b)	$
Foreign currency derivatives (c)	$ (1.4)	$	$	$	$	$	$

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) For the three months ended June 30, 2012 and 2011, 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. The ineffective portion is included in gains (losses) from commodity derivative activity, net in our condensed consolidated statements of operations.
(c) Relates to Discovery, our unconsolidated affiliate.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Loss Recognized in AOCI on Derivatives Effective Portion		Loss Reclassified From AOCI to Earnings Effective Portion		Loss Recognized in Income on Derivatives Ineffective Portion and Amount Excluded From Effectiveness Testing		Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	Six Months Ended June 30,						
	2012	2011	2012	2011	2012	2011	
	(Millions)		(Millions)		(Millions)		(Millions)
Interest rate derivatives	$ (0.2)	$ (4.2)	$ (9.3)	$ (10.3) (a)	$ (2.1)	$ (a)(e)	$ (2.7)
Commodity derivatives	$ (0.6)	$ (0.1)	$	$ (0.1) (b)	$ (0.1)	$ (c)	$
Foreign currency derivatives (d)	$ (0.5)	$	$	$	$	$	$

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) Included in gains (losses) from commodity derivative activity, net in our condensed consolidated statements of operations.
(c) For the six months ended June 30, 2012 and 2011, 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. The ineffective portion is included in gains (losses) from commodity derivative activity, net in our condensed consolidated statements of operations.
(d) Relates to Discovery, our unconsolidated affiliate.
(e) For the six months ended June 30, 2012, $0.6 million of derivative losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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

Commodity Derivatives: Statements of Operations Line Item	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Millions)			
Third party:				
Realized	$ (4.9)	$ (9.1)	$ 11.1	$ (15.9)
Unrealized	42.0	23.1	17.0	(9.2)
Gains (losses) from commodity derivative activity, net	$ 37.1	$ 14.0	$ 28.1	$ (25.1)
Affiliates:				
Realized	$ 15.4	$ (0.1)	$ 16.7	$ 1.4
Unrealized	22.8	(0.2)	25.2	(2.8)
Gains (losses) from commodity derivative activity, net affiliates	$ 38.2	$ (0.3)	$ 41.9	$ (1.4)

Interest Rate Derivatives: Statements of Operations Line Item

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(Millions)			
Third party:				
Realized losses	$ (3.4)	$ (1.3)	$ (6.3)	$ (2.3)
Unrealized gains	3.5	1.2	6.3	2.8
Interest gain (expense)	$ 0.1	$ (0.1)	$	$ 0.5

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

	June 30, 2012			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Position (MMBtu)	Net (Short) Position (Bbls)	Net Long (Short) position (MMbtu)
2012	(351,493)	(5,702,500)	(1,224,358)	3,645,000
2013	(932,504)	(2,865,000)	(700,975)	6,472,500
2014	(547,500)	(365,000)	(629,625)	(900,000)
2015	(365,000)		(155,250)	
2016	(183,000)			

	June 30, 2011			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Long Position (MMBtu)	Net (Short) Position (Bbls)	Net (Short) Long position (MMbtu)
2011	(178,281)	(11,615,100)	(633,195)	(2,750,000)
2012	(1,021,587)	(9,686,000)		10,460,000
2013	(941,998)	1,135,000		1,800,000
2014	(547,500)	(365,000)		
2015	(365,000)			
2016	(183,000)			

We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of June 30, 2012, we have swaps with a notional value of $70.0 million and $80.0 million, which, in aggregate, exchange $150.0 million of our floating rate obligation to a fixed rate obligation through June 2014.

12. 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, as defined below, to unitholders of record on the applicable record date, as determined by our general partner.

On June 14, 2012, we filed a universal shelf registration statement on Form S-3 with the SEC with an unlimited offering amount, to replace an existing shelf registration statement. The universal shelf registration statement will allow us to issue additional partnership equity and debt securities. As of June 30, 2012, we have issued no securities under this registration statement.

In March 2012, we issued 5,148,500 common units at $47.42 per unit. We received proceeds of $234.2 million, net of offering costs.

In March 2012, we issued 1,000,417 common units to DCP Midstream, LLC as partial consideration for the remaining 66.67% interest in Southeast Texas.

In February 2012, we issued 30,701 common units under our 2005 Long-Term Incentive Plan, or 2005 LTIP, to employees as compensation for their service.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

In January 2012, we issued 727,520 common units to DCP Midstream, LLC as partial consideration for the remaining 49.9% interest in East Texas.

On August 17, 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, common units having an aggregate offering amount of up to $150.0 million. During the three and six months ended June 30, 2012, we issued 338,800 of our common units pursuant to the equity distribution agreement, and received proceeds of $14.1 million, net of commissions and offering costs of $0.3 million, which were used to finance growth opportunities and general corporate purposes.

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

less the amount of cash reserves established by the general partner to:

provide for the proper conduct of our business;

comply with applicable law, any of our debt instruments or other agreements; and

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

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

General Partner Interest and Incentive Distribution Rights The general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 1% and limited partner interest of 1% as of June 30, 2012. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest.

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

Distributions of Available Cash after the Subordination Period Our partnership agreement, after adjustment for the general partner s relative ownership level, requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period, which ended in February 2009, in the following manner:

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

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

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

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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following table presents our cash distributions paid in 2012 and 2011:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
May 15, 2012	$ 0.6600	$ 42.6
February 14, 2012	$ 0.6500	$ 36.7
November 14, 2011	$ 0.6400	$ 34.9
August 12, 2011	$ 0.6325	$ 34.0
May 13, 2011	$ 0.6250	$ 33.4
February 14, 2011	$ 0.6175	$ 30.0

13. Equity-Based Compensation

On November 28, 2005, the board of directors of our General Partner adopted a Long-Term Incentive Plan, or the 2005 LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 2005 LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be issued and delivered pursuant to awards under the 2005 LTIP. Awards that are canceled or forfeited, or are withheld to satisfy the General Partner s tax withholding obligations, are available for delivery pursuant to other awards.

On February 15, 2012, the board of directors of our General Partner adopted a 2012 LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 2012 LTIP provides for the grant of phantom units and the grant of DERs.

The 2005 and 2012 LTIPs are administered by the compensation committee of the General Partner s board of directors. All awards are subject to cliff vesting.

14. Income Taxes

We are structured as a limited partnership, which is a pass-through entity for federal income tax purposes.

15. Net Income or Loss per Limited Partner Unit

Basic net income per limited partner unit is computed based on the weighted average number of units outstanding during the period. Diluted net income per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Dilutive potential units include outstanding performance units, phantom units and restricted units. The dilutive effect of unit-based awards was 28,510 and 75,560 equivalent units during the three months ended June 30, 2012 and June 30, 2011, respectively, and 40,681 and 55,105 equivalent units during the six months ended June 30, 2012 and June 30, 2011, respectively

16. Commitments and Contingent Liabilities

Prospect During the fourth quarter of 2011, we received a claim for arbitration (the Claim) filed with the American Arbitration Association by Prospect Street Energy, LLC and Prospect Street Ventures I, LLC (together, the Claimants) against EE Group, LLC (EE Group) and a number of other parties that previously owned, directly or indirectly, our Marysville NGL storage facility (collectively, the Respondents). EE Group is our indirect subsidiary which we acquired in connection with our acquisition of Marysville Hydrocarbons Holdings, LLC (Marysville) on December 30, 2010 (the Acquisition). The Claim involves actions taken and time periods prior to our ownership of EE Group and Marysville, and includes several causes of action including claims of civil conspiracy, breach of fiduciary duty and fraud. We acquired a 90% interest in Marysville from Dart Energy Corporation, a 5% interest in Marysville from Prospect Street Energy, LLC and a 100% interest in EE Group, which owned the remaining 5% interest in Marysville. The Claimants seek, from the Respondents collectively, alleged actual, punitive and treble damages and disgorgement of profits, as well as fees and costs. The purchase agreements for the Acquisition contain indemnification and other provisions that may provide some protection to us for any breach of the representations, warranties and

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

covenants made by the sellers in the Acquisition. At this point, we cannot predict whether we will have any liability for the Claim. This proceeding is subject to the uncertainties inherent in any litigation, and the ultimate outcome of this matter may not be known for an extended period of time. We intend to vigorously defend this matter.

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

Insurance We renewed our insurance policies in May, June and July 2012 for the 2012-2013 insurance year. We contract with third party and affiliate insurers for: (1) automobile liability insurance for all owned, non-owned and hired vehicles; (2) general liability insurance; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) property insurance, which covers replacement value of real and personal property and includes business interruption/extra expense. These renewals have not resulted in any material change to the premiums we are contracted to pay in the 2012-2013 insurance year compared with the 2011-2012 insurance year. We are jointly insured with DCP Midstream, LLC for 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 that are of similar size to us and with similar types of operations.

Our insurance on Discovery for the 2012-2013 insurance year includes general and excess liability, onshore property damage, including named windstorm and business interruption, and offshore non-wind property and business interruption insurance. The availability of offshore named windstorm property and business interruption insurance has been significantly reduced over the past few years as a result of higher industry-wide damage claims. Additionally, the named windstorm property and business interruption insurance that is available comes at uneconomic premium levels, higher deductibles and lower coverage limits. As such, Discovery has elected to not purchase offshore named windstorm property and business interruption insurance coverage for the 2012-2013 insurance year.

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, and 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 results of operations, financial position or cash flows.

During the first quarter of 2011, we discovered excess emissions at our East Texas gas plant. We met with the Texas Commission on Environmental Quality, or TCEQ, in April 2011 to discuss this matter and included these issues in Title V reports we submitted to the State. In August 2011, the TCEQ conducted a standard inspection at the East Texas gas plant to evaluate compliance with applicable air quality requirements. On August 31, 2011, the TCEQ issued us a Notice of Violation and a Notice of Enforcement citing a number of alleged violations of terms and requirements of the facility air permit. We responded to the Notice of Violation on September 28, 2011, including the implemented measures to ensure the facility is in compliance with the relevant air permit terms and conditions. We responded to the Notice of Enforcement on October 14, 2011, including a description of the measures that have been implemented, and will be implemented at the facility to ensure compliance with the relevant air permit terms and conditions. The TCEQ assessed a penalty of $0.6 million to resolve this matter, a portion which was paid during the first quarter of 2012. We were only responsible for 50.1% of this penalty and DCP Midstream, LLC was responsible for the remainder of the penalty under the terms of our acquisition of a 49.9% interest in East Texas from DCP Midstream, LLC on January 3, 2012.

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.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

17. Business Segments

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

Natural Gas Services Our Natural Gas Services segment provides services that include gathering, compressing, treating, processing, transporting and storing natural gas. The segment consists of our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our Michigan system, our Southeast Texas system, our East Texas system, our 75% interest in the Colorado system, and our 40% interest in Discovery.

NGL Logistics Our NGL Logistics segment provides services that include transportation, storage and fractionation of NGLs. The segment consists of the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, our 10% interest in the Texas Express NGL pipeline, the NGL storage facility in Michigan and the DJ Basin NGL Fractionators in Colorado.

Wholesale Propane Logistics Our Wholesale Propane Logistics segment provides services that include the receipt of propane by pipeline, rail or ship to our terminals that deliver the product to retail distributors. The segment consists of six owned rail terminals, one owned marine import terminal, one leased marine terminal, one pipeline terminal and access to several open-access pipeline terminals.

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following tables set forth our segment information:

Three Months Ended June 30, 2012

	Natural Gas Services (e)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations(f)	Total
			(Millions)			
Total operating revenue	$ 326.2	$ 14.5	$ 73.1	$	$ (0.1)	$ 413.7
Total purchases	(202.3)		(72.0)		(0.1)	(274.2)
Gross margin (a)	$ 123.9	$ 14.5	$ 1.1	$	$	$ 139.5
Operating and maintenance expense	(22.6)	(3.5)	(3.6)			(29.7)
Depreciation and amortization expense	(8.2)	(0.8)	(0.6)			(9.6)
General and administrative expense				(11.0)		(11.0)
Other income		0.2				0.2
Earnings from unconsolidated affiliates	2.0					2.0
Interest expense, net				(11.1)		(11.1)
Income tax expense (b)				(0.5)		(0.5)
Net income (loss)	95.1	10.4	(3.1)	(22.6)		79.8
Net income attributable to noncontrolling interests	(0.7)					(0.7)
Net income (loss) attributable to partners	$ 94.4	$ 10.4	$ (3.1)	$ (22.6)	$	$ 79.1
Non-cash derivative mark-to-market (c)	$ 49.2	$	$ 15.6	$ 0.4	$	$ 65.2

Three Months Ended June 30, 2011

	Natural Gas Services (e)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations(f)	Total
			(Millions)			
Total operating revenue	$ 458.8	$ 12.6	$ 104.2	$	$	$ 575.6
Total purchases	(355.2)		(98.0)			(453.2)
Gross margin (a)	$ 103.6	$ 12.6	$ 6.2	$	$	$ 122.4
Operating and maintenance expense	(20.0)	(1.8)	(4.2)			(26.0)
Depreciation and amortization expense	(22.0)	(2.0)	(0.7)			(24.7)
General and administrative expense				(11.5)		(11.5)
Other income		0.1				0.1
Earnings from unconsolidated affiliates	5.7					5.7
Interest expense, net				(8.4)		(8.4)

Income tax expense (b)				(0.2)		(0.2)
Net income (loss)	67.3	8.9	1.3	(20.1)		57.4
Net income attributable to noncontrolling interests	(9.7)					(9.7)
Net income (loss) attributable to partners	$ 57.6	$ 8.9	$ 1.3	$ (20.1)	$	$ 47.7
Non-cash derivative mark-to-market (c)	$ 23.3	$	$ (0.5)	$ (0.8)	$	$ (22.0)

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Six Months Ended June 30, 2012

	Natural Gas Services (e)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations(f)	Total
			(Millions)			
Total operating revenue	$ 631.9	$ 30.4	$ 277.1	$	$ (0.1)	$ 939.3
Total purchases	(450.7)		(254.8)		(0.1)	(705.4)
Gross margin (a)	$ 181.2	$ 30.4	$ 22.3	$	$	$ 233.9
Operating and maintenance expense	(40.9)	(7.7)	(7.4)			(56.0)
Depreciation and amortization expense	(30.5)	(3.0)	(1.3)			(34.8)
General and administrative expense				(22.9)		(22.9)
Other income		0.3				0.3
Earnings from unconsolidated affiliates	7.7					7.7
Interest expense, net				(23.7)		(23.7)
Income tax expense (b)				(0.7)		(0.7)
Net income (loss)	117.5	20.0	13.6	(47.3)		103.8
Net income attributable to noncontrolling interests	(1.4)					(1.4)
Net income (loss) attributable to partners	$ 116.1	$ 20.0	$ 13.6	$ (47.3)	$	$ 102.4
Non-cash derivative mark-to-market (c)	$ 26.2	$	$ 16.0	$ (0.8)	$	$ 41.4
Capital expenditures	$ 95.3	$ 2.9	$ 1.6	$	$	$ 99.8
Acquisition expenditures	$ 291.6	$	$	$	$	$ 291.6

Six Months Ended June 30, 2011

	Natural Gas Services (e)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations(f)	Total
			(Millions)			
Total operating revenue	$ 832.1	$ 27.6	$ 352.0	$	$ (2.2)	$ 1,209.5
Total purchases	(688.8)	(4.7)	(324.0)		2.2	(1,015.3)
Gross margin (a)	$ 143.3	$ 22.9	$ 28.0	$	$	$ 194.2
Operating and maintenance expense	(41.0)	(5.8)	(7.8)			(54.6)
Depreciation and amortization expense	(43.9)	(3.7)	(1.4)			(49.0)
General and administrative expense				(23.2)		(23.2)
Other income		0.2				0.2

Earnings from unconsolidated affiliates	10.2					10.2
Interest expense, net				(16.4)		(16.4)
Income tax expense (b)				(0.5)		(0.5)
Net income (loss)	68.6	13.6	18.8	(40.1)		60.9
Net income attributable to noncontrolling interests	(13.2)					(13.2)
Net income (loss) attributable to partners	$ 55.4	$ 13.6	$ 18.8	$ (40.1)	$	$ 47.7
Non-cash derivative mark-to-market (c)	$ (11.3)	$	$ (0.8)	$ (1.0)	$	$ (13.1)
Capital expenditures	$ 60.6	$ 6.3	$ 1.5	$	$	$ 68.4
Acquisition expenditures	$ 121.9	$ 29.6	$	$	$	$ 151.5

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	June 30, 2012	December 31, 2011
	(Millions)	
Segment long-term assets:		
Natural Gas Services (e)	$ 1,651.6	$ 1,555.4
NGL Logistics	270.2	250.1
Wholesale Propane Logistics	104.6	104.2
Other (d)	52.4	14.0
Total long-term assets	2,078.8	1,923.7
Current assets	254.7	353.7
Total assets	$ 2,333.5	$ 2,277.4

(a) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane, NGLs and condensate. 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) For the three and six months ended June 30, 2011, income tax expense relates primarily to the Texas margin tax and the Michigan business tax. The Michigan business tax was repealed in 2012; accordingly, income tax expense for the three and six months ended June 30, 2012 relates primarily to the Texas margin tax.

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

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

(e) The segment information for the three and six months ended June 30, 2012 and 2011, and as of December 31, 2011, include the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

(f) Represents intersegment revenues consisting of sales of NGLs by Marysville in our NGL Logistics business to our Wholesale Propane business.

18. Supplemental Cash Flow Information

	Six Months Ended June 30, 2012	2011
	(Millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$ 6.4	$ 2.2
Cash paid for income taxes, net of income tax refunds	$ 0.7	$ 29.9
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable	$ 15.5	$ 7.6
Other non-cash additions of property, plant and equipment	$ 5.8	$ 0.1

Non-cash change in parent advances	$	$ 4.4
Non-cash distributions to DCP Midstream, LLC	$	$ 2.6

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

19. Supplementary Information Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream Partners, LP, or parent guarantor, DCP Midstream Operating LP, or subsidiary issuer, which is a 100% owned subsidiary, and non-guarantor subsidiaries, as well as the consolidating adjustments necessary to present DCP Midstream Partners, LP s results on a consolidated basis. In conjunction with the universal shelf registration statement on Form S-3 filed with the SEC on June 14, 2012, the parent guarantor has agreed to fully and unconditionally guarantee securities of the subsidiary issuer. For the purpose of the following financial information, investments in subsidiaries are reflected in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Balance Sheets June 30, 2012				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$	$ 8.0	$ 2.5	$ (5.0)	$ 5.5
Accounts receivable			119.8		119.8
Inventories			74.0		74.0
Other		0.1	55.3		55.4
Total current assets		8.1	251.6	(5.0)	254.7
Property, plant and equipment, net			1,578.7		1,578.7
Goodwill and intangible assets, net			294.9		294.9
Advances receivable consolidated subsidiaries	620.4	769.8		(1,390.2)	
Investments in consolidated subsidiaries	464.4	642.2		(1,106.6)	
Investments in unconsolidated affiliates			147.1		147.1
Other long-term assets		7.8	50.3		58.1
Total assets	$ 1,084.8	$ 1,427.9	$ 2,322.6	$ (2,501.8)	$ 2,333.5
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$	$ 11.5	$ 220.0	$ (5.0)	$ 226.5
Advances payable consolidated subsidiaries			1,390.2	(1,390.2)	
Long-term debt		948.3			948.3
Other long-term liabilities		3.7	35.4		39.1
Total liabilities		963.5	1,645.6	(1,395.2)	1,213.9
Commitments and contingent liabilities					
Equity:					
Partners equity					
Net equity	1,084.8	474.7	648.7	(1,106.6)	1,101.6
Accumulated other comprehensive loss		(10.3)	(6.5)		(16.8)
Total partners equity	1,084.8	464.4	642.2	(1,106.6)	1,084.8
Noncontrolling interests			34.8		34.8
Total equity	1,084.8	464.4	677.0	(1,106.6)	1,119.6
Total liabilities and equity	$ 1,084.8	$ 1,427.9	$ 2,322.6	$ (2,501.8)	$ 2,333.5

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Balance Sheets December 31, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$	$ 3.6	$ 6.4	$ (2.4)	$ 7.6
Accounts receivable			214.8		214.8
Inventories			87.9		87.9
Other			43.4		43.4
Total current assets		3.6	352.5	(2.4)	353.7
Property, plant and equipment, net			1,499.4		1,499.4
Goodwill and intangible assets, net			299.1		299.1
Advances receivable consolidated subsidiaries	370.7	597.2		(967.9)	
Investments in consolidated subsidiaries	515.2	679.3		(1,194.5)	
Investments in unconsolidated affiliates			107.1		107.1
Other long-term assets		5.6	12.5		18.1
Total assets	$ 885.9	$ 1,285.7	$ 2,270.6	$ (2,164.8)	$ 2,277.4
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$	$ 18.7	$ 364.2	$ (2.4)	$ 380.5
Advances payable consolidated subsidiaries			967.9	(967.9)	
Long-term debt		746.8			746.8
Other long-term liabilities		5.0	46.8		51.8
Total liabilities		770.5	1,378.9	(970.3)	1,179.1
Commitments and contingent liabilities					
Equity:					
Partners equity					
Predecessor equity			257.4		257.4
Net equity	885.9	534.6	423.7	(1,194.5)	649.7
Accumulated other comprehensive loss		(19.4)	(1.8)		(21.2)
Total partners equity	885.9	515.2	679.3	(1,194.5)	885.9
Noncontrolling interests			212.4		212.4
Total equity	885.9	515.2	891.7	(1,194.5)	1,098.3
Total liabilities and equity	$ 885.9	$ 1,285.7	$ 2,270.6	$ (2,164.8)	$ 2,277.4

(a)

The financial information as of December 31, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Operations Three Months Ended June 30, 2012				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$	$	$ 296.5	$	$ 296.5
Transportation, processing and other			41.9		41.9
Gains from commodity derivative activity, net			75.3		75.3
Total operating revenues			413.7		413.7
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs			274.2		274.2
Operating and maintenance expense			29.7		29.7
Depreciation and amortization expense			9.6		9.6
General and administrative expense			11.0		11.0
Other income			(0.2)		(0.2)
Total operating costs and expenses			324.3		324.3
Operating income			89.4		89.4
Interest expense, net		(10.5)	(0.6)		(11.1)
Income from consolidated subsidiaries	79.1	89.6		(168.7)	
Earnings from unconsolidated affiliates			2.0		2.0
Income before income taxes	79.1	79.1	90.8	(168.7)	80.3
Income tax expense			(0.5)		(0.5)
Net income	79.1	79.1	90.3	(168.7)	79.8
Net income attributable to noncontrolling interests			(0.7)		(0.7)
Net income attributable to partners	$ 79.1	$ 79.1	$ 89.6	$ (168.7)	$ 79.1

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Comprehensive Income Three Months Ended June 30, 2012				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
Net income	$ 79.1	$ 79.1	$ 90.3	$ (168.7)	$ 79.8
Other comprehensive income:					
Reclassification of cash flow hedges into earnings		4.0			4.0
Net unrealized losses on cash flow hedges		(0.4)	(1.2)		(1.6)
Other comprehensive income from consolidated subsidiaries	2.4	(1.2)		(1.2)	
Total other comprehensive income	2.4	2.4	(1.2)	(1.2)	2.4
Total comprehensive income	81.5	81.5	89.1	(169.9)	82.2
Total comprehensive income attributable to noncontrolling interests			(0.7)		(0.7)
Total comprehensive income attributable to partners	$ 81.5	$ 81.5	$ 88.4	$ (169.9)	$ 81.5

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Operations Three Months Ended June 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$	$	$ 521.5	$	$ 521.5
Transportation, processing and other			40.4		40.4
Gains from commodity derivative activity, net			13.7		13.7
Total operating revenues			575.6		575.6
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs			453.2		453.2
Operating and maintenance expense			26.0		26.0
Depreciation and amortization expense			24.7		24.7
General and administrative expense			11.5		11.5
Other income			(0.1)		(0.1)
Total operating costs and expenses			515.3		515.3
Operating income			60.3		60.3
Interest expense, net		(8.4)			(8.4)
Income from consolidated subsidiaries	47.7	56.1		(103.8)	
Earnings from unconsolidated affiliates			5.7		5.7
Income before income taxes	47.7	47.7	66.0	(103.8)	57.6
Income tax expense			(0.2)		(0.2)
Net income	47.7	47.7	65.8	(103.8)	57.4
Net income attributable to noncontrolling interests			(9.7)		(9.7)
Net income attributable to partners	$ 47.7	$ 47.7	$ 56.1	$ (103.8)	$ 47.7

(a) The financial information for the three months ended June 30, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Comprehensive Income Three Months Ended June 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
Net income	$ 47.7	$ 47.7	$ 65.8	$ (103.8)	$ 57.4
Other comprehensive income:					
Reclassification of cash flow hedges into earnings		5.1			5.1
Net unrealized losses on cash flow hedges		(3.3)	(0.1)		(3.4)
Net unrealized losses on cash flow hedges - predecessor			(0.4)		(0.4)
Other comprehensive income from consolidated subsidiaries	1.3	(0.5)		(0.8)	
Total other comprehensive income	1.3	1.3	(0.5)	(0.8)	1.3
Total comprehensive income	49.0	49.0	65.3	(104.6)	58.7
Total comprehensive income attributable to noncontrolling interests			(9.7)		(9.7)
Total comprehensive income attributable to partners	$ 49.0	$ 49.0	$ 55.6	$ (104.6)	$ 49.0

(a) The financial information for the three months ended June 30, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Operations Six Months Ended June 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$	$	$ 783.6	$	$ 783.6
Transportation, processing and other			85.7		85.7
Gains from commodity derivative activity, net			70.0		70.0
Total operating revenues			939.3		939.3
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs			705.4		705.4
Operating and maintenance expense			56.0		56.0
Depreciation and amortization expense			34.8		34.8
General and administrative expense			22.9		22.9
Other income			(0.3)		(0.3)
Total operating costs and expenses			818.8		818.8
Operating income			120.5		120.5
Interest expense, net		(22.9)	(0.8)		(23.7)
Income from consolidated subsidiaries	102.4	125.3		(227.7)	
Earnings from unconsolidated affiliates			7.7		7.7
Income before income taxes	102.4	102.4	127.4	(227.7)	104.5
Income tax expense			(0.7)		(0.7)
Net income	102.4	102.4	126.7	(227.7)	103.8
Net income attributable to noncontrolling interests			(1.4)		(1.4)
Net income attributable to partners	$ 102.4	$ 102.4	$ 125.3	$ (227.7)	$ 102.4

(a) The financial information for the six months ended June 30, 2012 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Comprehensive Income Six Months Ended June 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
Net income	$ 102.4	$ 102.4	$ 126.7	$ (227.7)	$ 103.8
Other comprehensive income:					
Reclassification of cash flow hedges into earnings		9.3			9.3
Net unrealized losses on cash flow hedges		(0.2)	(0.5)		(0.7)
Net unrealized losses on cash flow hedges - predecessor			(0.6)		(0.6)
Other comprehensive income from consolidated subsidiaries	8.0	(1.1)		(6.9)	
Total other comprehensive income	8.0	8.0	(1.1)	(6.9)	8.0
Total comprehensive income	110.4	110.4	125.6	(234.6)	111.8
Total comprehensive income attributable to noncontrolling interests			(1.4)		(1.4)
Total comprehensive income attributable to partners	$ 110.4	$ 110.4	$ 124.2	$ (234.6)	$ 110.4

(a) The financial information for the six months ended June 30, 2012 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Operations Six Months Ended June 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$	$	$ 1,156.6	$	$ 1,156.6
Transportation, processing and other			79.4		79.4
Losses from commodity derivative activity, net			(26.5)		(26.5)
Total operating revenues			1,209.5		1,209.5
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs			1,015.3		1,015.3
Operating and maintenance expense			54.6		54.6
Depreciation and amortization expense			49.0		49.0
General and administrative expense			23.2		23.2
Other income			(0.2)		(0.2)
Total operating costs and expenses			1,141.9		1,141.9
Operating income			67.6		67.6
Interest expense, net		(16.4)			(16.4)
Income from consolidated subsidiaries	47.7	64.1		(111.8)	
Earnings from unconsolidated affiliates			10.2		10.2
Income before income taxes	47.7	47.7	77.8	(111.8)	61.4
Income tax expense			(0.5)		(0.5)
Net income	47.7	47.7	77.3	(111.8)	60.9
Net income attributable to noncontrolling interests			(13.2)		(13.2)
Net income attributable to partners	$ 47.7	$ 47.7	$ 64.1	$ (111.8)	$ 47.7

(a) The financial information for the six months ended June 30, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Comprehensive Income Six Months Ended June 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 47.7	$ 47.7	$ 77.3	$ (111.8)	$ 60.9
Other comprehensive income:					
Reclassification of cash flow hedges into earnings		10.3	0.1		10.4
Net unrealized losses on cash flow hedges		(4.2)	(0.1)		(4.3)
Net unrealized losses on cash flow hedges - predecessor			(0.4)		(0.4)
Other comprehensive income from consolidated subsidiaries	5.7	(0.4)		(5.3)	
Total other comprehensive income	5.7	5.7	(0.4)	(5.3)	5.7
Total comprehensive income	53.4	53.4	76.9	(117.1)	66.6
Total comprehensive income attributable to noncontrolling interests			(13.2)		(13.2)
Total comprehensive income attributable to partners	$ 53.4	$ 53.4	$ 63.7	$ (117.1)	$ 53.4

(a) The financial information for the six months ended June 30, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Cash Flows Six Months Ended June 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ (168.6)	$ (193.8)	$ 436.6	$ (2.6)	$ 71.6
INVESTING ACTIVITIES:					
Capital expenditures			(99.8)		(99.8)
Acquisitions, net of cash acquired			(291.6)		(291.6)
Investments in unconsolidated affiliates			(42.4)		(42.4)
Return of investment in unconsolidated affiliates			1.0		1.0
Proceeds from sale of assets			0.1		0.1
Net cash used in investing activities			(432.7)		(432.7)
FINANCING ACTIVITIES:					
Proceeds from debt		1,008.4			1,008.4
Payments of debt		(807.0)			(807.0)
Payment of deferred financing costs		(3.2)			(3.2)
Proceeds from issuance of common units, net of offering costs	248.0				248.0
Distributions to unitholders and general partner	(79.4)				(79.4)
Distributions to noncontrolling interests			(3.2)		(3.2)
Contributions from DCP Midstream, LLC			6.9		6.9
Net change in advances to predecessor from DCP Midstream, LLC			(11.5)		(11.5)
Net cash provided by (used in) financing activities	168.6	198.2	(7.8)		359.0
Net change in cash and cash equivalents		4.4	(3.9)	(2.6)	(2.1)
Cash and cash equivalents, beginning of period		3.6	6.4	(2.4)	7.6
Cash and cash equivalents, end of period	$	$ 8.0	$ 2.5	$ (5.0)	$ 5.5

(a) The financial information for the six months ended June 30, 2012 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Condensed Consolidating Statements of Cash Flows Six Months Ended June 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ (76.0)	$ (62.9)	$ 244.7	$ 0.5	$ 106.3
INVESTING ACTIVITIES:					
Capital expenditures			(68.4)		(68.4)
Acquisitions, net of cash acquired			(151.5)		(151.5)
Investments in unconsolidated affiliates			(2.8)		(2.8)
Return of investment in unconsolidated affiliates			1.6		1.6
Proceeds from sale of assets			0.2		0.2
Net cash used in investing activities			(220.9)		(220.9)
FINANCING ACTIVITIES:					
Proceeds from debt		716.0			716.0
Payments of debt		(653.0)			(653.0)
Payments of deferred financing cost		(0.1)			(0.1)
Proceeds from issuance of common units, net of offering cost	139.4				139.4
Excess purchase price over acquired assets			(35.7)		(35.7)
Distributions to unitholders and general partner	(63.4)				(63.4)
Distributions to noncontrolling interests			(15.8)		(15.8)
Contributions from DCP Midstream, LLC			5.6		5.6
Net change in advances to predecessor from DCP Midstream, LLC			17.8		17.8
Net cash provided by (used in) financing activities	76.0	62.9	(28.1)		110.8
Net change in cash and cash equivalents			(4.3)	0.5	(3.8)
Cash and cash equivalents, beginning of period		1.5	6.7	(1.5)	6.7
Cash and cash equivalents, end of period	$	$ 1.5	$ 2.4	$ (1.0)	$ 2.9

(a) The financial information during the six months ended June 30, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

20. Subsequent Events

On July 2, 2012, we closed a private placement of equity with a group of institutional investors in which we sold 4,989,802 common units at a price of $35.55 per unit, and received proceeds of $173.8 million net of offering costs. In connection with the closing of this private placement, we entered into a registration rights agreement, and filed a shelf registration statement on Form S-3 with the SEC to register the units.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

On July 2, 2012, we acquired the minority ownership interests in two non-operated Mont Belvieu fractionators, or the Mont Belvieu fractionators, from DCP Midstream, LLC for aggregate consideration of $200.0 million. $60.0 million of the aggregate consideration was financed by the issuance at closing of 1,536,098 of our common units to DCP Midstream, LLC. We entered into a 2-year Term Loan Agreement to fund the remaining $140.0 million. The minority ownership interests include a 12.5% interest in the Enterprise fractionator, which is operated by Enterprise, and a 20% interest in the Mont Belvieu 1 fractionator, which is operated by ONEOK Partners. The contribution of the minority ownership interests in the Mont Belvieu fractionators represents a transaction between entities under common control, but does not represent a change in reporting entity. Accordingly, we will include the results of the minority ownership interests in the Mont Belvieu fractionators prospectively from the date of acquisition. The Mont Belvieu fractionators will be accounted for as unconsolidated affiliates using the equity method.

On July 3, 2012, we acquired the Crossroads processing plant and associated gathering system from Penn Virginia Resource Partners, L.P. for $63.0 million. The cash purchase was financed at closing with borrowings under our revolving credit facility. The Crossroads system, located in the southeastern portion of Harrison County in East Texas, includes approximately 8 miles of gas gathering pipeline, an 80 MMcf/d cryogenic processing plant, approximately 20 miles of NGL pipeline and a 50% ownership in an approximately 11-mile residue gas pipeline. Given the recent timing of this acquisition, we have not completed the accounting for the Crossroads business combination and have not made certain disclosures. The initial accounting and related disclosures for business combinations will be made in subsequent financial statements.

On July 26, 2012, the board of directors of the General Partner declared a quarterly distribution of $0.67 per unit, payable on August 14, 2012 to unitholders of record on August 7, 2012.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and the consolidated financial statements and notes thereto included in our 2011 Form 10-K included as Exhibit 99.3 to our Current Report on Form 8-K filed on June 14, 2012.

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. Our operations are organized into three business segments: Natural Gas Services, NGL Logistics and Wholesale Propane Logistics.

Our business is impacted by both commodity prices, which we partially mitigate through a multi-year hedging program, as well as volumes of throughput and sales of natural gas and natural gas liquids. Various factors impact both commodity prices and volumes. Commodity prices historically have been volatile and continue to be volatile. Crude oil prices have generally remained at favorable levels, while natural gas liquids prices have declined recently in relation to crude prices. Recent weakening of the relationship of natural gas liquids to crude oil prices does somewhat impact the effectiveness of our hedging program where we use crude oil to hedge our NGL price exposure. Natural gas liquids and natural gas prices are currently below levels seen in recent years due to increasing supplies and a near record warm winter. Although we have not experienced a significant impact to our natural gas throughput volumes as a result of decreased commodity prices, if commodity prices remain weak for a sustained period, our natural gas throughput volumes may be impacted, particularly if producers were to shut in gas. Natural gas drilling activity levels vary by geographic area, but in general, drilling remains firm in areas with liquids rich gas. Drilling remains weak in certain areas with dry gas where low commodity prices currently do not support the economics of drilling. However, advances in technology, such as horizontal drilling and hydraulic fracturing in shale plays, have led to certain geographic areas becoming increasingly accessible. Our long-term view is that commodity prices will be at levels that we believe will support sustained or increasing levels of domestic natural gas production.

NGL prices are also impacted by the demand from petro-chemical and refining industries. The petro-chemical industry is making significant investment in building or expanding facilities to convert chemical plants from heavier oil-based feed stock to lighter NGL-based feed stock, including ethane. This increased demand should support increasing ethane supplies. In addition, propane export facilities are also being expanded or built, which is expected to support increasing propane supply. Although there can be, and has been, near-term volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to support increasing supply.

The global economic outlook, particularly the European debt crisis, has become a cause for concern for U.S. financial markets as businesses and investors alike struggle to determine the impact these troubled nations will have domestically. A slowdown in global economic growth or a potential liquidity crisis may lead to further declines in commodity prices. This uncertainty may contribute to continuing volatility in financial and commodity markets.

Increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low historical cost have enabled us to continue executing our multi-faceted growth strategy, with an emphasis on co-investment with DCP Midstream, LLC. Co-investment capital commitments since the beginning of 2011 are nearly $1.0 billion.

Some of our recent growth projects include the following:

- On January 3, 2012, we closed on the previously announced acquisition of the remaining 49.9% interest in East Texas from DCP Midstream, LLC for $165.0 million.

- On March 30, 2012, we closed on the previously announced acquisition of the remaining 66.67% interest in the Southeast Texas joint venture for $240.0 million.

- On April 12, 2012, we acquired a 10% ownership interest in the Texas Express Pipeline joint venture from the operator, Enterprise Products Partners, L.P., representing a total investment of approximately $85.0 million.

On July 2, 2012, we acquired the minority ownership interests in two non-operated Mont Belvieu fractionators, or the Mont Belvieu fractionators, from DCP Midstream, LLC for aggregate consideration of $200.0 million.

On July 3, 2012, we acquired the Crossroads processing plant and associated gathering system from Penn Virginia Resource Partners, L.P. for $63.0 million.

Our construction of the Eagle 200 MMcf/d natural gas processing plant is progressing and is expected to be online in the fourth quarter of 2012. Our expansion plan for the Discovery natural gas gathering pipeline system is also progressing and is expected to be completed in mid-2014. Once completed, both projects are expected to enhance our portfolio through additional fee-based margins.

Our capital markets execution has positioned us well in terms of both liquidity and cost of capital to execute our growth plans, including co-investment opportunities with DCP Midstream, LLC. In March, we raised $234.4 million in capital through a public equity offering and $345.8 million through a public debt offering of 4.95% 10-year Senior Notes, which were used to finance our growth opportunities and repay borrowings on our credit facility. During the three months ended June 30, 2012, we issued 338,800 of our common units pursuant to our equity distribution agreement and received proceeds of $14.1 million, net of commissions and offering costs of $0.3 million. On June 14, 2012, we filed a universal shelf registration statement on Form S-3 with the SEC with an unlimited offering amount, to replace an existing shelf registration statement. The universal shelf registration statement will allow us to issue additional partnership equity and debt securities. On July 2, 2012, we sold 4,989,802 common units in a private placement at a price of $35.55 per unit, and received proceeds of $173.8 million net of offering costs. As of June 30, 2012, the unused capacity under the revolving credit facility was $648.9 million, of which approximately $567.2 million was available for general working capital purposes, providing liquidity to continue to execute on our growth plans.

Financial results for 2012 are expected to be in line with our 2012 forecast. We raised our distributions for the quarter, resulting in a 5.9% increase in our quarterly distribution rate over the rate declared in the second quarter of 2011. The distributions reflect our business results as well as our recent execution on growth opportunities.

General Trends and Outlook

In 2012, our strategic objectives will continue to focus on maintaining stable distributable cash flows from our existing assets and executing on growth opportunities to increase our long-term distributable cash flows. We believe the key elements to stable distributable cash flows are the diversity of our asset portfolio, our significant fee-based business representing approximately 60% of our estimated margins, plus our highly hedged commodity position, the objective of which is to protect against downside risk in our distributable cash flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $15.0 million and $20.0 million, and approved expenditures for expansion capital of approximately $1.0 billion, for the year ending December 31, 2012. Expansion capital expenditures include construction of the Texas Express Pipeline and Discovery s Keathley Canyon, which are shown as investments in unconsolidated affiliates, construction of the Eagle Plant, expansion and upgrades to our East Texas complex, and acquisitions, including the remainder of East Texas and Southeast Texas, the Mont Belvieu fractionators and the Crossroads processing plant in East Texas. The board of directors may, at its discretion, approve additional growth capital during the year.

In 2012, we expect to continue to pursue a multi-faceted growth strategy, which includes maximizing opportunities provided by our partnership with DCP Midstream, LLC, pursuing strategic and accretive third party acquisitions and capitalizing on organic expansion opportunities in order to grow our distributable cash flows. Given the significant level of growth opportunities currently in DCP Midstream, LLC s footprint, we would expect substantially more emphasis on our co-investment objective over the next few years.

For an in-depth discussion of factors that may significantly affect our results, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Factors That May Significantly Affect Our Results included as Exhibit 99.2 to our Current Report on Form 8-K filed on June 14, 2012.

Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas for all periods presented. We refer to our 100% interest in Southeast Texas, prior to our acquisition from DCP Midstream, LLC in March 2012, as our predecessor. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC s basis in the net assets contributed. The amount of the purchase price in excess or in deficit of DCP Midstream, LLC s basis in the net assets is recognized as a reduction or an addition to partners equity. The 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.

Recent Events

On June 14, 2012, we filed a universal shelf registration statement on Form S-3 with the SEC with an unlimited offering amount, to replace an existing shelf registration statement. The universal shelf registration statement will allow us to issue additional partnership equity and debt securities.

On July 2, 2012, we closed a private placement of equity with a group of institutional investors in which we sold 4,989,802 common units at a price of $35.55 per unit, and received proceeds of $173.8 million net of offering costs. In connection with the closing of this private placement, we entered into a registration rights agreement, and filed a shelf registration statement on Form S-3 with the SEC to register the units.

On July 2, 2012, we acquired the minority ownership interests in two non-operated Mont Belvieu fractionators, or the Mont Belvieu fractionators, from DCP Midstream, LLC for aggregate consideration of $200.0 million. $60.0 million of the aggregate consideration was financed by the issuance at closing of 1,536,098 of our common units to DCP Midstream, LLC. We entered into a 2-year Term Loan Agreement to fund the remaining $140.0 million. The minority ownership interests include a 12.5% interest in the Enterprise fractionator, which is operated by Enterprise, and a 20% interest in the Mont Belvieu 1 fractionator, which is operated by ONEOK Partners. The contribution of the minority ownership interests in the Mont Belvieu fractionators represents a transaction between entities under common control, but does not represent a change in reporting entity. Accordingly, we will include the results of the minority ownership interests in the Mont Belvieu fractionators prospectively from the date of acquisition. The Mont Belvieu fractionators will be accounted for as unconsolidated affiliates using the equity method.

On July 3, 2012, we acquired the Crossroads processing plant and associated gathering system from Penn Virginia Resource Partners, L.P., or PVR, for $63.0 million. The cash purchase was financed at closing with borrowings under our revolving credit facility. The Crossroads system, located in the southeastern portion of Harrison County in East Texas, includes approximately 8 miles of gas gathering pipeline, an 80 MMcf/d cryogenic processing plant, approximately 20 miles of NGL pipeline and a 50% ownership in an approximately 11-mile residue gas pipeline.

On July 26, 2012, the board of directors of the General Partner declared a quarterly distribution of $0.67 per unit, payable on August 14, 2012 to unitholders of record on August 7, 2012.

Reconciliation of Non-GAAP Measures

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

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We define gross margin as total operating revenues, including commodity derivative activity, 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 commodity derivative losses, less non-cash commodity derivative gains for that segment. Gross margin, segment gross margin and adjusted segment gross margin are primary performance measures used by management, as these measures represent the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin, segment gross margin and adjusted segment gross margin should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States of America, or GAAP.

Adjusted EBITDA We define adjusted EBITDA as net income or loss attributable to partners less interest income, noncontrolling interest in depreciation and income tax expense and non-cash commodity derivative gains, plus interest expense, income tax expense, depreciation and amortization expense and non-cash commodity derivative losses. Our adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate this measure in the same manner.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, 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.

Adjusted Segment EBITDA We define adjusted segment EBITDA for each segment as segment net income or loss attributable to partners less non-cash commodity derivative gains for that segment, plus depreciation and amortization expense and non-cash commodity derivative losses for that segment, adjusted for any noncontrolling interest on depreciation and amortization expense for that segment. Our adjusted segment EBITDA may not be comparable to similarly titled measures of other companies because they may not calculate adjusted segment EBITDA in the same manner.

Adjusted segment EBITDA should not be considered in isolation or as an alternative to our financial measures presented in accordance with GAAP, including net income or loss attributable to Partners, or any other measure of performance presented in accordance with GAAP.

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

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing methods or capital structure;
- viability and performance of acquisitions and capital expenditure projects and the overall rates of return on investment opportunities; and
- performance of our business excluding non-cash commodity derivative gains or losses;
- in the case of Adjusted EBITDA, 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.

The accompanying schedules provide reconciliations of adjusted segment EBITDA to its most directly comparable GAAP financial measure.

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Distributable Cash Flow We define Distributable Cash Flow as net cash provided by or used in operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, proceeds from divestiture of assets, net income attributable to noncontrolling interest net of depreciation and income tax, 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 or earnings capacity. 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 and interest rates. Distributable Cash Flow is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess 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.

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

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	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of net income attributable to partners to gross margin:				
Net income attributable to partners	$ 79.1	$ 47.7	$ 102.4	$ 47.7
Interest expense	11.1	8.4	23.7	16.4
Income tax expense	0.5	0.2	0.7	0.5
Operating and maintenance expense	29.7	26.0	56.0	54.6
Depreciation and amortization expense	9.6	24.7	34.8	49.0
General and administrative expense	11.0	11.5	22.9	23.2
Other income	(0.2)	(0.1)	(0.3)	(0.2)
Earnings from unconsolidated affiliates	(2.0)	(5.7)	(7.7)	(10.2)
Net income attributable to noncontrolling interests	0.7	9.7	1.4	13.2
Gross margin	$ 139.5	$ 122.4	$ 233.9	$ 194.2
Non-cash commodity derivative mark-to-market (a)	$ 64.8	$ 22.8	$ 42.2	$ (12.1)
Reconciliation of segment net income attributable to partners to segment gross margin:				
Natural Gas Services segment:				
Segment net income attributable to partners	$ 94.4	$ 57.6	$ 116.1	$ 55.4
Operating and maintenance expense	22.6	20.0	40.9	41.0
Depreciation and amortization expense	8.2	22.0	30.5	43.9
Earnings from unconsolidated affiliates	(2.0)	(5.7)	(7.7)	(10.2)
Net income attributable to noncontrolling interests	0.7	9.7	1.4	13.2
Segment gross margin	$ 123.9	$ 103.6	$ 181.2	$ 143.3
Non-cash commodity derivative mark-to-market (a)	$ 49.2	$ 23.3	$ 26.2	$ (11.3)
NGL Logistics segment:				
Segment net income attributable to partners	$ 10.4	$ 8.9	$ 20.0	$ 13.6
Operating and maintenance expense	3.5	1.8	7.7	5.8
Depreciation and amortization expense	0.8	2.0	3.0	3.7
Other income	(0.2)	(0.1)	(0.3)	(0.2)
Segment gross margin	$ 14.5	$ 12.6	$ 30.4	$ 22.9
Wholesale Propane Logistics segment:				
Segment net (loss) income attributable to partners	$ (3.1)	$ 1.3	$ 13.6	$ 18.8
Operating and maintenance expense	3.6	4.2	7.4	7.8
Depreciation and amortization expense	0.6	0.7	1.3	1.4
Segment gross margin	$ 1.1	$ 6.2	$ 22.3	$ 28.0
Non-cash commodity derivative mark-to-market (a)	$ 15.6	$ (0.5)	$ 16.0	$ (0.8)

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

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	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Millions)			
Reconciliation of segment net income attributable to partners to adjusted segment EBITDA:				
Natural Gas Services segment:				
Segment net income attributable to partners (a)	$ 94.4	$ 57.6	$ 116.1	$ 55.4
Non-cash commodity derivative mark-to-market	(49.2)	(23.3)	(26.2)	11.3
Depreciation and amortization expense	8.2	22.0	30.5	43.9
Noncontrolling interest on depreciation and income tax	(0.4)	(3.2)	(0.8)	(6.8)
Adjusted segment EBITDA	$ 53.0	$ 53.1	$ 119.6	$ 103.8
NGL Logistics segment:				
Segment net income attributable to partners	$ 10.4	$ 8.9	$ 20.0	$ 13.6
Depreciation and amortization expense	0.8	2.0	3.0	3.7
Adjusted segment EBITDA	$ 11.2	$ 10.9	$ 23.0	$ 17.3
Wholesale Propane Logistics segment:				
Segment net (loss) income attributable to partners (b)	$ (3.1)	$ 1.3	$ 13.6	$ 18.8
Non-cash commodity derivative mark-to-market	(15.6)	0.5	(16.0)	0.8
Depreciation and amortization expense	0.6	0.7	1.3	1.4
Adjusted segment EBITDA	$ (18.1)	$ 2.5	$ (1.1)	$ 21.0

(a) Includes no lower of cost or market adjustments for the three months ended June 30, 2012 and June 30, 2011. We recognized $3.9 million and $0.5 million lower of cost or market adjustments during the six months ended June 30, 2012 and June 30, 2011, respectively.

(b) Includes lower of cost or market adjustments of $14.5 million during the three months ended June 30, 2012 and no charges or adjustments for the three months ended June 30, 2011. We recognized $15.2 million and $0.1 million lower of cost or market adjustments during the six months ended June 30, 2012 and June 30, 2011, respectively.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2011 Form 10-K included as Exhibit 99.2 to our Current Report on Form 8-K filed on June 14, 2012. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three and six months ended June 30, 2012 are the same as those described in Exhibit 99.2 to the above-mentioned Current Report on Form 8-K, as updated by recent accounting pronouncements that we have adopted in Note 2 of the Notes to Condensed Consolidated Financial Statements in Item 1. Financial Statements .

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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, 2012 and 2011. 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 2012 vs. 2011		Variance Six Months 2012 vs. 2011	
	2012 (a)(b)(c)	2011 (a)(c)(d)	2012 (a)(b)(c)	2011 (a)(c)(d)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues (e):								
Natural Gas Services	$ 326.2	$ 458.8	$ 631.9	$ 832.1	$ (132.6)	(29)%	$ (200.2)	(24)%
NGL Logistics	14.5	12.6	30.4	27.6	1.9	15 %	2.8	10 %
Wholesale Propane Logistics	73.1	104.2	277.1	352.0	(31.1)	(30)%	(74.9)	(21)%
Intra-segment Eliminations	(0.1)		(0.1)	(2.2)	(0.1)	(100)%	2.1	95 %
Total operating revenues	413.7	575.6	939.3	1,209.5	(161.9)	(28)%	(270.2)	(22)%
Gross margin (f):								
Natural Gas Services	123.9	103.6	181.2	143.3	20.3	20 %	37.9	26 %
NGL Logistics	14.5	12.6	30.4	22.9	1.9	15 %	7.5	33 %
Wholesale Propane Logistics	1.1	6.2	22.3	28.0	(5.1)	(82)%	(5.7)	(20)%
Total gross margin	139.5	122.4	233.9	194.2	17.1	14 %	39.7	20 %
Operating and maintenance expense	(29.7)	(26.0)	(56.0)	(54.6)	3.7	14 %	1.4	3 %
Depreciation and amortization expense	(9.6)	(24.7)	(34.8)	(49.0)	(15.1)	(61)%	(14.2)	(29)%
General and administrative expense	(11.0)	(11.5)	(22.9)	(23.2)	(0.5)	(4)%	(0.3)	(1)%
Other income	0.2	0.1	0.3	0.2	0.1	100 %	0.1	50 %
Earnings from unconsolidated affiliates (g)	2.0	5.7	7.7	10.2	(3.7)	(65)%	(2.5)	(25)%
Interest expense	(11.1)	(8.4)	(23.7)	(16.4)	2.7	32 %	7.3	45 %
Income tax expense	(0.5)	(0.2)	(0.7)	(0.5)	0.3	150 %	0.2	40 %
Net income attributable to noncontrolling interests	(0.7)	(9.7)	(1.4)	(13.2)	(9.0)	(93)%	(11.8)	(89)%
Net income attributable to partners	$ 79.1	$ 47.7	$ 102.4	$ 47.7	$ 31.4	66 %	$ 54.7	115 %
Other data:								
Non-cash commodity derivative mark-to-market	$ 64.8	$ 22.8	$ 42.2	$ (12.1)	$ 42.0	184 %	$ 54.3	*
Natural gas throughput (MMcf/d) (g)	1,607	1,440	1,644	1,460	167	12 %	184	13 %
NGL gross production (Bbls/d) (g)	62,771	54,843	62,978	55,831	7,928	14 %	7,147	13 %
NGL pipelines throughput (Bbls/d) (g)	72,786	59,129	77,740	52,421	13,657	23 %	25,319	48 %
Propane sales volume (Bbls/d)	11,641	16,538	23,010	28,288	(4,897)	(30)%	(5,278)	(19)%

* Percentage change is not meaningful.

(a) On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative instruments related to the Southeast Texas storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas, in our Natural Gas Services segment, for the three and six months ended June 30, 2012 and 2011.

(b) Includes the results of our acquisition of the remaining 49.9% interest in East Texas, since January 3, 2012, the date of acquisition, in our Natural Gas Services segment.

(c) Includes the results of our DJ Basin NGL Fractionators since the date of acquisition of March 24, 2011, in our NGL Logistics Segment.

(d) We utilize commodity derivative instruments to provide stability to distributable cash flows for our ownership in East Texas as well as all other natural gas services assets. On January 3, 2012, we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC. For the three and six months ended June 30, 2011, the 49.9% interest in East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 49.9% of East Texas, unhedged for the three and six months ended June 30, 2011.

(e) Operating revenues include the impact of commodity derivative activity

(f) 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 Reconciliation of Non-GAAP Measures above.

(g) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of Collbran, Jackson Pipeline Company, or Jackson, and Discovery and our share of earnings for Discovery. Earnings for Discovery include the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

Three Months Ended June 30, 2012 vs. Three Months Ended June 30, 2011

Total Operating Revenues Total operating revenues decreased $161.9 million in 2012 compared to 2011 primarily as a result of the following:

- $131.7 million decrease primarily attributable to lower NGL and natural gas prices;

- $47.8 million decrease attributable to reduced Wholesale Propane Logistics segment volumes as a result of near record warm weather and lower propane prices; and

- $44.0 million decrease due to lower volumes, lower gas storage revenue and the East Texas recovery settlement in 2011.

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These decreases were partially offset by:

- $61.6 million increase related to commodity derivative activity including $41.9 million increase in non-cash derivative mark-to-market gains and $19.7 million increase in settled derivatives. Included in our derivative activity are an increase in unrealized losses of $11.2 million and an increase in realized gains of $8.5 million from the predecessor s Southeast Texas storage business.

Gross Margin Gross margin increased $17.1 million in 2012 compared to 2011, primarily as a result of the following:

- $20.3 million increase for our Natural Gas Services segment, primarily related to commodity derivative activity, partially offset by lower commodity prices, the East Texas recovery settlement in 2011, decreased volumes and differences in gas quality across certain assets; and

- $1.9 million increase for our NGL Logistics segment as a result of the completion of the Wattenberg expansion project and increased throughput on our pipelines.

These increases were partially offset by:

- $5.1 million decrease for our Wholesale Propane Logistics segment, due to a non-cash lower of cost or market inventory adjustment and reduced volumes as a result of near record warm weather, partially offset by commodity derivative activities discussed above.

Operating and Maintenance Expense Operating and maintenance expense increased in 2012 compared to 2011 as a result of timing of expenditures and the completion of the Wattenberg capital expansion project.

Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful life of our assets.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Net income attributable to noncontrolling interests Net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of our acquisition of the remaining 49.9% of East Texas.

Six Months Ended June 30, 2012 vs. Six Months Ended June 30, 2011

Total Operating Revenues Total operating revenues decreased $270.2 million in 2012 compared to 2011 primarily as a result of the following:

- $187.4 million decrease primarily attributable to lower NGL and natural gas prices;

- $93.2 million decrease attributable to reduced Wholesale Propane Logistics segment volumes as a result of near record warm weather; and

- $86.1 million decrease primarily due to lower volumes, lower gas storage revenue and the East Texas recovery settlement in 2011, partially offset by the increase in in transportation, processing and other revenue.

These decreases were partially offset by:

$96.5 million increase related to commodity derivative activity including $54.2 million increase in non-cash derivative mark-to-market gain and $42.3 million increase in settled derivatives. Included in our derivative activity are an increase in unrealized losses of $21.9 million and an increase in realized gains of $28.2 million from the predecessor s Southeast Texas storage business.

Gross Margin Gross margin increased $39.7 million in 2012 compared to 2011, primarily as a result of the following:

- $37.9 million increase for our Natural Gas Services segment, primarily related to commodity derivative activity, partially offset by decreased volumes across certain assets, lower commodity prices and the East Texas recovery settlement in 2011; and

- $7.5 million increase for our NGL Logistics segment as a result of the completion of the Wattenberg expansion project, increased throughput on our pipelines, and our acquisition of the DJ Basin NGL Fractionators.

These increases were partially offset by:

- $5.7 million decrease for our Wholesale Propane Logistics segment due to a non-cash lower of cost or market inventory adjustment, reduced volumes as a result of near record warm weather, partially offset by commodity derivative activities discussed above.

Operating and Maintenance Expense Operating and maintenance expense increased in 2012 compared to 2011 as a result of timing of expenditures, the completion of the Wattenberg capital expansion project and our acquisition of the DJ Basin NGL Fractionators.

Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful life of our assets.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes, partially offset by timing of expenditures. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Net income attributable to noncontrolling interests Net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of our acquisition of the remaining 49.9% of East Texas.

Results of Operations Natural Gas Services Segment

This segment consists of our Northern Louisiana system, the Southern Oklahoma system, a 40% interest in Discovery, our Southeast Texas system, a 75% operating interest in our Colorado system, our Wyoming system, our East Texas system, and our Michigan system.

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2012 vs. 2011		Variance Six Months 2012 vs. 2011	
	2012 (b)	2011 (a)(b)	2012 (b)	2011 (a)(b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 239.5	$ 416.5	$ 523.4	$ 800.6	$ (177.0)	(42)%	$ (277.2)	(35)%
Transportation, processing and other	27.4	27.9	55.3	56.5	(0.5)	(2)%	(1.2)	(2)%
Gains (losses) from commodity derivative activity	59.3	14.4	53.2	(25.0)	44.9	312 %	78.2	*
Total operating revenues	326.2	458.8	631.9	832.1	(132.6)	(29)%	(200.2)	(24)%
Purchases of natural gas and NGLs	202.3	355.2	450.7	688.8	(152.9)	(43)%	(238.1)	(35)%
Segment gross margin (c)	123.9	103.6	181.2	143.3	20.3	20 %	37.9	26 %
Operating and maintenance expense	(22.6)	(20.0)	(40.9)	(41.0)	2.6	13 %	(0.1)	%
Depreciation and amortization expense	(8.2)	(22.0)	(30.5)	(43.9)	(13.8)	(63)%	(13.4)	(31)%
Earnings from unconsolidated affiliates (e)	2.0	5.7	7.7	10.2	(3.7)	(65)%	(2.5)	(25)%
Segment net income	95.1	67.3	117.5	68.6	27.8	41 %	48.9	71 %
Segment net income attributable to noncontrolling interests	(0.7)	(9.7)	(1.4)	(13.2)	(9.0)	(93)%	(11.8)	(89)%
Segment net income attributable to partners	$ 94.4	$ 57.6	$ 116.1	$ 55.4	$ 36.8	64 %	$ 60.7	110 %
Other data:								
Non-cash commodity derivative mark-to-market	$ 49.2	$ 23.3	$ 26.2	$ (11.3)	$ 25.9	111 %	$ 37.5	*
Natural gas throughput (MMcf/d) (d)	1,607	1,440	1,644	1,460	167	12 %	184	13 %
NGL gross production (Bbls/d) (d)	62,771	54,843	62,978	55,831	7,928	14 %	7,147	13 %

* Percentage change is not meaningful.

(a) We utilize commodity derivative instruments to provide stability to distributable cash flows for our ownership in East Texas as well as all other natural gas services assets. On January 3, 2012 we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC. For the three and six months ended June 30, 2011, the 49.9% interest in East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 49.9% of East Texas, unhedged for the three and six months ended June 30, 2011.

(b) On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative instruments related to the Southeast Texas storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas for the three and six months ended June 30, 2012 and 2011.

(c) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read Reconciliation of Non-GAAP Measures above.

(d) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of Collbran, Jackson Pipeline Company, or Jackson, and Discovery and our share of earnings for Discovery. Earnings for Discovery include the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

Three Months Ended June 30, 2012 vs. Three Months Ended June 30, 2011

Total Operating Revenues Total operating revenues decreased $132.6 million in 2012 compared to 2011, primarily as a result of the following:

- $75.2 million decrease attributable to lower commodity prices;
- $62.9 million decrease attributable to decreased prices and volumes for physical sales related to our natural gas storage and pipeline assets;
- $33.1 million decrease primarily attributable to decreased volumes across certain assets;
- $5.8 million decrease as a result of the East Texas recovery settlement in 2011; and
- $0.5 million decrease in transportation, processing and other revenues.

These decreases were partially offset by:

- $44.9 million increase related to commodity derivative activity. This includes an increase in unrealized gains in 2012 compared to 2011of $25.8 million due to movements in forward prices of commodities, and realized cash settlement gains in 2012 compared to realized cash settlement losses in 2011 for a net increase of $19.1 million. Included in our derivative activity are an increase in unrealized losses of $11.2 million and an increase in realized gains of $8.5 million from the predecessor s Southeast Texas storage business.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased $152.9 million in 2012 compared to 2011 primarily as a result of lower commodity prices and lower volumes.

Segment Gross Margin Segment gross margin increased $20.3 million in 2012 compared to 2011, primarily as a result of the following:

- $44.9 million increase related to commodity derivative activities as discussed above.

This increase was partially offset by:

- $13.3 million decrease as a result of lower commodity prices;
- $5.8 million decrease as a result of the East Texas recovery settlement in 2011; and
- $5.5 million decrease primarily attributable to decreased volumes across certain assets.

Operating and Maintenance Expense Operating and maintenance expense increased in 2012 compared to 2011 as a result of timing of expenditures.

Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful life of our assets.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

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Segment net income attributable to noncontrolling interests Segment net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of the acquisition of the remaining 49.9% of East Texas.

Natural Gas Throughput Natural gas transported, processed and/or treated increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of East Texas, partially offset by decreased volumes across certain assets.

NGL Gross Production NGL production increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of East Texas, partially offset by decreased volumes and differences in gas quality across certain assets.

Six Months Ended June 30, 2012 vs. Six Months Ended June 30, 2011

Total Operating Revenues Total operating revenues decreased $200.2 million in 2012 compared to 2011, primarily as a result of the following:

- $116.1 million decrease attributable to decreased prices and volumes for physical sales related to our natural gas storage and pipeline assets;

- $91.6 million decrease attributable to lower commodity prices;

- $63.7 million decrease primarily attributable to decreased volumes across certain assets and differences in gas quality;

- $5.8 million decrease as a result of the East Texas recovery settlement in 2011; and

- $1.2 million decrease in transportation, processing and other revenues.

These decreases were partially offset by:

- $78.2 million increase related to commodity derivative activity. This includes a decrease in unrealized losses in 2012 compared to 2011of $37.4 million due to movements in forward prices of commodities, and realized cash settlement gains in 2012 compared to realized cash settlement losses in 2011 for a net increase of $40.8 million. Included in our derivative activity are an increase in unrealized losses of $21.9 million and an increase in realized gains of $28.2 million from the predecessor s Southeast Texas storage business.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased $238.1 million in 2012 compared to 2011 primarily as a result of lower commodity prices and decreased volumes across certain assets.

Segment Gross Margin Segment gross margin increased $37.9 million in 2012 compared to 2011, primarily as a result of the following:

- $78.2 million increase related to commodity derivative activities as discussed in the Operating Revenues section above.

This increase was partially offset by:

- $21.1 million decrease primarily attributable to decreased volumes and differences in gas quality across certain assets.

- $13.4 million decrease as a result of lower commodity prices; and

- $5.8 million decrease as a result of the East Texas recovery settlement in 2011.

Operating and Maintenance Expense Operating and maintenance expense remained relatively constant in 2012 compared to 2011.

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Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful life of our assets.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes, partially offset by timing of expenditures. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Segment net income attributable to noncontrolling interests Segment net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of the acquisition of the remaining 49.9% of East Texas.

Natural Gas Throughput Natural gas transported, processed and/or treated increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of East Texas, partially offset by decreased volumes across certain assets.

NGL Gross Production NGL production increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of East Texas, partially offset by decreased volumes and differences in gas quality across certain assets.

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Results of Operations NGL Logistics Segment

This segment includes our Seabreeze, Wilbreeze, Wattenberg and Black Lake transportation pipelines, our 10% interest in the Texas Express NGL pipeline, our Marysville NGL storage facility and our DJ Basin NGL Fractionators:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2012 vs. 2011		Variance Six Months 2012 vs. 2011	
	2012 (b)	2011 (b)	2012 (b)	2011 (b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of NGLs	$	$ 0.1	$	$ 4.9	$ (0.1)	(100)%	$ (4.9)	(100)%
Transportation, processing and other	14.5	12.5	30.4	22.7	2.0	16 %	7.7	34 %
Total operating revenues	14.5	12.6	30.4	27.6	1.9	15 %	2.8	10 %
Purchases of NGLs				4.7		%	(4.7)	(100)%
Segment gross margin (a)	14.5	12.6	30.4	22.9	1.9	15 %	7.5	33 %
Operating and maintenance expense	(3.5)	(1.8)	(7.7)	(5.8)	1.7	94 %	1.9	33 %
Depreciation and amortization expense	(0.8)	(2.0)	(3.0)	(3.7)	(1.2)	(60)%	(0.7)	(19)%
Other income	0.2	0.1	0.3	0.2	0.1	100 %	0.1	50 %
Segment net income attributable to partners	$ 10.4	$ 8.9	$ 20.0	$ 13.6	$ 1.5	17 %	$ 6.4	47 %
Other data:								
NGL pipelines throughput (Bbls/d)	72,786	59,129	77,740	52,421	13,657	23 %	25,319	48 %

(a) Segment gross margin consists of total operating revenues less purchases of NGLs. Please read Reconciliation of Non-GAAP Measures above.
(b) Includes the results of our DJ Basin NGL Fractionators since the date of acquisition of March 24, 2011.

Three Months Ended June 30, 2012 vs. Three Months Ended June 30, 2011

Total Operating Revenues Total operating revenues increased in 2012 compared to 2011 as result of the completion of the Wattenberg capital expansion project and increased throughput on our pipelines.

Segment Gross Margin Segment gross margin increased in 2012 compared to 2011 as result of the completion of the Wattenberg capital expansion project and increased throughput on our pipelines.

Operating and Maintenance Expense Operating and maintenance expense increased in 2012 compared to 2011 due to timing of expenditures and the completion of the Wattenberg capital expansion project.

Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful life of our assets.

NGL Pipelines Throughput NGL pipelines throughput increased in 2012 compared to 2011 as a result of volume growth on our pipelines and the completion of the Wattenberg capital expansion project.

Six Months Ended June 30, 2012 vs. Six Months Ended June 30, 2011

Total Operating Revenues Total operating revenues increased in 2012 compared to 2011 as result of the completion of the Wattenberg capital expansion project, increased throughput on our pipelines and our acquisition of the DJ Basin NGL Fractionators.

Segment Gross Margin Segment gross margin increased in 2012 compared to 2011 as result of the completion of the Wattenberg capital expansion project, increased throughput on our pipelines and our acquisition of the DJ Basin NGL Fractionators.

Operating and Maintenance Expense Operating and maintenance expense increased in 2012 compared to 2011 due to timing of expenditures, the completion of the Wattenberg capital expansion project and our acquisition of the DJ Basin NGL Fractionators.

Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful life of our assets.

NGL Pipelines Throughput NGL pipelines throughput increased in 2012 compared to 2011 as a result of volume growth on our pipelines and the completion of the Wattenberg capital expansion project.

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Results of Operations Wholesale Propane Logistics Segment

This segment consists of our propane terminals, which include six owned and operated rail terminals, one owned marine import terminal, one leased marine terminal, one pipeline terminal and access to several open-access propane pipeline terminals.

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2012 vs. 2011		Variance Six Months 2012 vs. 2011	
	2012	2011	2012	2011	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of propane	$ 57.0	$ 104.9	$ 260.2	$ 353.3	$ (47.9)	(46)%	$ (93.1)	(26)%
Other	0.1		0.1	0.2	0.1	100 %	(0.1)	(50)%
(Losses) gains from commodity derivative activity	16.0	(0.7)	16.8	(1.5)	16.7	*	18.3	*
Total operating revenues	73.1	104.2	277.1	352.0	(31.1)	(30)%	(74.9)	(21)%
Purchases of propane	72.0	98.0	254.8	324.0	(26.0)	(27)%	(69.2)	(21)%
Segment gross margin (a)	1.1	6.2	22.3	28.0	(5.1)	(82)%	(5.7)	(20)%
Operating and maintenance expense	(3.6)	(4.2)	(7.4)	(7.8)	(0.6)	(14)%	(0.4)	(5)%
Depreciation and amortization expense	(0.6)	(0.7)	(1.3)	(1.4)	(0.1)	(14)%	(0.1)	(7)%
Segment net (loss) income attributable to partners	$ (3.1)	$ 1.3	$ 13.6	$ 18.8	$ (4.4)	*	$ (5.2)	(28)%
Other data:								
Non-cash commodity derivative mark-to-market	$ 15.6	$ (0.5)	$ 16.0	$ (0.8)	$ 16.1	*	$ 16.8	*
Propane sales volume (Bbls/d)	11,641	16,538	23,010	28,288	(4,897)	(30)%	(5,278)	(19)%

* Percentage change is not meaningful.

(a) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of propane. Please read Reconciliation of Non-GAAP Measures above.

Three Months Ended June 30, 2012 vs. Three Months Ended June 30, 2011

Total Operating Revenues Total operating revenues decreased by $31.1 million in 2012 compared to 2011, primarily as a result of the following:

- $30.9 million decrease attributable to reduced volumes primarily as a result of near record warm weather; and

- $16.9 million decrease attributable to lower propane prices.

These decreases were partially offset by:

- $16.7 million increase related to a change in unrealized commodity derivative activity of $16.1 million and a change in realized cash settlements of $0.6 million.

Purchases of Propane Purchases of propane decreased in 2012 compared to 2011 primarily due to reduced volumes as a result of near record warm weather and lower propane prices, partially offset by a non-cash lower of cost or market inventory adjustment of $14.5 million.

Segment Gross Margin Segment gross margin decreased in 2012 compared to 2011 primarily due to a non-cash lower of cost or market inventory adjustment of $14.5 million and reduced volumes as a result of near record warm weather, partially offset by commodity derivative activities of $16.7 million discussed above.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2012 compared to 2011 due to timing of expenditures.

Depreciation and Amortization Expense Depreciation and amortization expense remained relatively constant in 2012 compared to 2011.

Propane Sales Volume Propane sales volumes decreased in 2012 compared to 2011 due to tempered demand as a result of near record warm weather.

Six Months Ended June 30, 2012 vs. Six Months Ended June 30, 2011

Total Operating Revenues Total operating revenues decreased $74.9 million in 2012 compared to 2011, primarily as a result of the following:

- $73.6 million decrease attributable to reduced volumes primarily as a result of near record warm weather; and

- $19.6 million decrease attributable to lower propane prices.

These decreases were partially offset by:

- $18.3 million increase related to a change in unrealized commodity derivative activity of $16.8 million and a change in realized commodity derivative activity of $1.5 million.

Purchases of Propane Purchases of propane decreased in 2012 compared to 2011 primarily due to reduced volumes as a result of near record warm weather, lower propane prices, and a non-cash lower of cost or market inventory adjustment of $15.2 million.

Segment Gross Margin Segment gross margin decreased in 2012 compared to 2011 primarily due to a non-cash lower of cost or market inventory adjustment of $15.2 million, reduced volumes as a result of near record warm weather, partially offset by commodity derivative activities of $18.3 million discussed above.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2012 compared to 2011 due to timing of expenditures.

Depreciation and Amortization Expense Depreciation and amortization expense remained relatively constant in 2012 compared to 2011.

Propane Sales Volume Propane sales volumes decreased in 2012 compared to 2011 due to tempered demand as a result of near record warm weather.

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Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our unconsolidated affiliates;
- borrowings under our revolving credit facility;
- borrowings under our term loan;
- issuance of additional common units;
- public and private debt offerings;
- guarantees issued by DCP Midstream, LLC, which reduce the amount of collateral we may be required to post with certain counterparties to our commodity derivative instruments; and
- letters of credit.

We anticipate our more significant uses of resources to include:

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

We believe that cash generated will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions for the next twelve months. In the event these sources are not sufficient, we would reduce our discretionary spending.

We routinely evaluate opportunities for strategic investments or acquisitions. Future material investments or acquisitions may require that we issue additional equity, assume third party debt or incur other long-term obligations. We have the option to utilize both equity and debt instruments as vehicles for the long-term financing of our investment activities and acquisitions.

Based on current and anticipated levels of operations, we believe we have adequate committed financial resources to conduct our business, although deterioration in our operating environment could limit our borrowing capacity, raise our financing costs, as well as impact our compliance with our financial covenant requirements under our Credit Agreement. Our sources of funding could include additional borrowings under our Credit Agreement, the placement of public and private debt, and the issuance of our common units.

Our Credit Agreement consists of a senior unsecured revolving credit facility with capacity of $1.0 billion, which matures on November 10, 2016. Our borrowing capacity is currently limited by the Credit Agreement s financial covenant requirements. Except in the case of a default, which would make the borrowings under the Credit Agreement fully callable, amounts borrowed under the Credit Agreement will not mature prior to the November 10, 2016 maturity date. As of August 3, 2012, we had approximately $693.9 million of unused capacity under the Credit Agreement.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through 2016 with fixed price commodity swaps and collar arrangements. For additional information regarding our derivative activities, please read Item7A. Quantitative and Qualitative Disclosures about Market Risk in our 2011 Form 10-K included as Exhibit 99.2 to our Current Report on Form 8-K filed on June 14, 2012 and Item 3. Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report on Form 10-Q.

On January 3, 2012, we entered into a 2-year Term Loan Agreement and borrowed $135.0 million which was used to fund the cash portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

On March 13, 2012, we issued $350.0 million of 4.95% 10-year Senior Notes due April 1, 2022. We received proceeds of $345.8 million, which are net of underwriters fees, related expenses and unamortized, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our January 3, 2012 Term Loan and Credit Facility.

On July 2, 2012, we entered into a 2-year Term Loan Agreement and borrowed $140.0 million to fund the cash portion of the acquisition of the Mont Belvieu fractionators.

In August 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, common units having an aggregate offering amount of up to $150.0 million. During the three and six months ended June 30, 2012, we issued 338,800 of our common units pursuant to this agreement, and received proceeds of $14.1 million, net of commissions and offering costs of $0.3 million.

In January 2012, we issued 727,520 common units to DCP Midstream, LLC as partial consideration for the remaining 49.9% interest in East Texas.

In March 2012, we issued 1,000,417 common units to DCP Midstream, LLC as partial consideration for the remaining 66.67% interest in Southeast Texas.

In March 2012, we issued 5,148,500 common units at $47.42 per unit. We received proceeds of $234.2 million, net of offering costs.

In June 2012, we filed a universal shelf registration statement on Form S-3 with the SEC with an unlimited offering amount, to replace an existing shelf registration statement. The universal shelf registration statement will allow us to issue additional partnership equity and debt securities. As of August 3, 2012, we have issued no securities under this registration statement.

On July 2, 2012, we closed a private placement of equity with a group of institutional investors in which we sold 4,989,802 common units at a price of $35.55 per unit, and received proceeds of $173.8 million net of offering costs. In connection with the closing of this private placement, we entered into a registration rights agreement, and filed a shelf registration statement on Form S-3 with the SEC to register the units.

In July 2012, we issued 1,536,098 common units to DCP Midstream, LLC as partial consideration for the Mont Belvieu fractionators.

The counterparties to each of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty s assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. As of August 3, 2012, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $50.0 million in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with these counterparties. We pay DCP Midstream, LLC a fee of 0.50% per annum on these guarantees. These parental guarantees reduce the amount of cash we may be required to post as collateral. As of August 3, 2012, we had no cash collateral posted with counterparties. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. Predetermined collateral thresholds for commodity derivative instruments guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC s credit rating and the thresholds would be reduced to zero 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. Current assets are reduced by our quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, inventory levels, and 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 other long-term assets.

We had working capital of $28.2 million as of June 30, 2012, compared to a working capital deficit of $26.8 million as of December 31, 2011. Included in these working capital amounts are net derivative working capital assets of $22.0 million and net derivative working capital liabilities of $18.7 million as of June 30, 2012 and December 31, 2011, respectively. The change in working capital is primarily attributable to the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

As of June 30, 2012, we had $5.5 million in cash and cash equivalents. Of this balance, as of June 30, 2012, $2.4 million was held by subsidiaries we do not wholly own, which we consolidate in our financial results. Other than the cash held by these subsidiaries, this cash balance was available for general corporate purposes. In 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, which has the potential to impact our cash collateral and reporting requirements for our derivative positions depending on the final regulations adopted by the United States Commodity Futures Trading Commission and the U.S. Securities and Exchange Commission.

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

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Millions)	
Net cash provided by operating activities	$ 71.6	$ 106.3
Net cash used in investing activities	$ (432.7)	$ (220.9)
Net cash provided by financing activities	$ 359.0	$ 110.8

Our predecessor s sources of liquidity, prior to its 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 net changes in parent advances to predecessors from DCP Midstream, LLC.

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

We received $29.6 million for our net hedge cash settlements related to the Southeast Texas storage business, offset by $1.8 million in other net cash hedge settlements paid, for the six months ended June 30, 2012. We received $1.4 million for our net hedge cash settlements related to the Southeast Texas Storage business, offset by $15.9 million in other net cash hedge settlements paid, for the six months ended June 30, 2011.

We received cash distributions from unconsolidated affiliates of $8.4 million and $11.9 million during the six months ended June 30, 2012 and 2011, respectively. Distributions exceeded earnings by $0.7 million and $1.7 million for the six months ended June 30, 2012 and 2011, respectively.

Net Cash Used in Investing Activities Net cash used in investing activities during the six months ended June 30, 2012 was comprised of: (1) acquisition expenditures of $291.6 million, of which $171.7 million is related to our acquisition of the remaining 66.67% interest in Southeast Texas, and $119.9 million related to our acquisition of the remaining 49.9% interest in East Texas ; (2) capital expenditures of $99.8 million (our portion of which was $90.5 million and the reimbursable projects portion was $9.3 million); (3) investments in unconsolidated affiliates of $42.4 million; partially offset by (4) return of investment from unconsolidated affiliate of $1.0 million; and (5) proceeds from sales of assets of $0.1 million.

Net cash used in investing activities during the six months ended June 30, 2011 was comprised of: (1) acquisition expenditures of $29.7 million related to our acquisition of our DJ Basin NGL Fractionators; (2) acquisition expenditures of $114.3 million, related to our acquisition of Southeast Texas; (3) payment of $7.5 million to the seller of Michigan Pipeline & Processing, LLC in relation to our contingent payment agreement; (4) capital expenditures of $68.4 million (our portion of which was $61.6 million and the noncontrolling interest holders portion was $6.8 million); and (5) investments in unconsolidated affiliates of $2.8 million; partially offset by (6) a return of investment from unconsolidated affiliates of $1.6 million; and (7) proceeds from sales of assets of $0.2 million.

Net Cash Provided by Financing Activities Net cash provided by financing activities during the six months ended June 30, 2012 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $248.0 million; (2) proceeds from debt of $1,008.4 million, offset by repayments of $807.0 million, for net borrowing of debt of $201.4 million; and (3) contributions from DCP Midstream, LLC of $6.9 million; partially offset by (4) distributions to our unitholders and general partner of $79.4 million; (5) net change in advances to predecessor from DCP Midstream, LLC of $11.5 million; (6) distributions to noncontrolling interests of $3.2 million; and (7) payment of deferred financing costs of $3.2 million.

Net cash provided by financing activities during the six months ended June 30, 2011 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $139.4 million; (2) net borrowing of debt of $63.0 million; (3) net change in advances to predecessor from DCP Midstream, LLC of $17.8 million; and (4) contributions from noncontrolling interests of $5.6 million; partially offset by (5) distributions to our unitholders and general partner of $63.4 million; (6) excess purchase price over the acquired net assets of Southeast Texas of $35.7 million; (7) distributions to noncontrolling interests of $15.8 million; and (8) payment of deferred financing costs of $0.1 million.

During the six months ended June 30, 2012, total outstanding indebtedness under our $1.0 billion Credit Agreement, which includes borrowings under our revolving credit facility and letters of credit issued under the Credit Agreement, was not less than $268.1 million and did not exceed $576.1 million. The weighted-average indebtedness outstanding for the six months ended June 30, 2012 was $432.5 million.

We had unused revolver capacity, which is available commitments under the Credit Agreement, of $648.9 million as of June 30, 2012.

During the six months ended June 30, 2012, we had the following net movements on our revolving credit facility:

- $234.2 million repayment financed by the issue of 5,148,500 common units in March 2012; partially offset by
- $87.2 million net borrowings.

During the six months ended June 30, 2011, we had the following net movements on our revolving credit facility:

- $150.0 million borrowing to fund the acquisition of our 33.33% interest in Southeast Texas; and
- $52.7 million net borrowings; partially offset by
- $139.7 million repayment financed by the issue of 3,596,636 common units in March 2011.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 12 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, including certain system integrity and safety improvements, or acquire or construct new capital assets if such expenditures are made to maintain, including over the long-term, our operating or earnings capacity; and expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets) in each case if such addition, improvement, acquisition or construction is made to increase our operating or earnings capacity.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $15.0 million and $20.0 million, and approved expenditures for expansion capital of approximately $1.0 billion, for the year ending December 31, 2012. Expansion capital expenditures include construction of the Texas Express Pipeline and Discovery s Keathley Canyon, which are shown as investments in unconsolidated affiliates, construction of the Eagle Plant, expansion and upgrades to our East Texas complex, and acquisitions, including the remainder of East Texas and Southeast Texas, the Mont Belvieu fractionators and the Crossroads processing plant in East Texas. The board of directors may, at its discretion, approve additional growth capital during the year.

The following table summarizes our maintenance and expansion capital expenditures for our consolidated entities.

	Six months ended June 30, 2012			Six months ended June 30, 2011		
	Maintenance Capital Expenditures	Expansion Capital Expenditures (Millions)	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures (Millions)	Total Consolidated Capital Expenditures
Our portion	$ 7.6	$ 82.9	$ 90.5	$ 5.0	$ 56.6	$ 61.6
Noncontrolling interest portion and reimbursable projects (a)	3.7	5.6	9.3	2.3	4.5	6.8
Total	$ 11.3	$ 88.5	$ 99.8	$ 7.3	$ 61.1	$ 68.4

(a) In conjunction with our acquisitions of our East Texas and Southeast Texas systems, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on capital projects. These reimbursements are for certain capital projects which have commenced within three years from the respective acquisition dates.

In addition, we invested cash in unconsolidated affiliates of $42.4 million and $2.8 million during the six months ended June 30, 2012 and 2011 to fund our share of capital expansion projects.

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

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our credit facility, the issuance of additional partnership units and the issuance of long-term debt. If these sources are not sufficient, we will reduce our discretionary spending.

Cash Distributions to Unitholders Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders and general partner of $79.4 million during the six months ended June 30, 2012, as compared to $63.4 million for the same period in 2011. We intend to continue making quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

Description of the Credit Agreement The Credit Agreement consists of a $1.0 billion revolving credit facility that matures November 10, 2016. As of June 30, 2012, the outstanding balance on the revolving credit facility was $350.0 million resulting in unused revolver capacity of $648.9 million, of which approximately $567.2 million was available for general working capital purposes.

Our obligations under the revolving credit facility are unsecured. The unused portion of the revolving credit facility may be used for letters of credit. At June 30, 2012 and December 31, 2011, we had $1.1 million outstanding letters of credit issued under the Credit Agreement.

As of June 30, 2012, the weighted-average interest rate on our revolving credit facility was 1.50% per annum, excluding the impact of interest rate swaps.

Description of the Term Loan Agreements On July 2, 2012, we entered into a 2-year Term Loan Agreement and borrowed $140.0 million to fund the cash portion of the acquisition of the Mont Belvieu fractionators.

The term loan will mature on July 2, 2014. The proceeds of any subsequent indebtedness issued with a maturity date after July 2, 2014 must be used to repay the term loan. Indebtedness under the term loan bears interest at either: (1) LIBOR, plus an applicable margin of 1.375% based on our current credit rating; or (2) (a) the higher of SunTrust Bank s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.25% based on our current credit rating. The Term Loan Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Term Loan Agreement) consistent with our Credit Agreement.

On January 3, 2012, we entered into a 2-year Term Loan Agreement and borrowed $135.0 million which was used to fund the cash portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

Description of Debt Securities On March 13, 2012, we issued $350.0 million of our 4.95% 10-year Senior Notes due April 1, 2022. We received net proceeds of $345.8 million, net of underwriters fees, related expenses and unamortized discounts of $4.2 million, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2012. The notes will mature on April 1, 2022, unless redeemed prior to maturity. The underwriters fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

Both series of notes are senior unsecured obligations, ranking equally in right of payment with our existing unsecured indebtedness, including indebtedness under our Credit Facility. We are not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at our option.

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Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of June 30, 2012, is as follows:

		Payments Due by Period			
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
			(Millions)		
Long-term debt (a)	$ 1,168.3	$ 33.1	$ 58.0	$ 639.3	$ 437.9
Operating lease obligations (b)	24.4	11.3	9.8	2.3	1.0
Purchase obligations (c)	216.5	109.4	55.0	52.1	
Other long-term liabilities (d)	17.3		0.5	0.2	16.6
Total	$ 1,426.5	$ 153.8	$ 123.3	$ 693.9	$ 455.5

(a) Includes interest payments on long-term debt that has been hedged and on debt securities that have been issued. Interest payments on long-term debt that has not been hedged are not included as these payments are based on floating interest rates and we cannot determine with accuracy the periodic repayment dates or the amounts of the interest payments.

(b) Our operating lease obligations are contractual obligations, and primarily consist of our leased marine propane terminal and railcar leases, both of which provide supply and storage infrastructure for our Wholesale Propane Logistics business. Operating lease obligations also include natural gas storage for our Pelico system. The natural gas storage arrangement enables us to maximize the value between the current price of natural gas and the futures market price of natural gas.

(c) Our purchase obligations are contractual obligations and include purchase orders for capital expenditures, various non-cancelable commitments to purchase physical quantities of propane supply for our Wholesale Propane Logistics business and other items. For contracts where the price paid is based on an index, the amount is based on the forward market prices as June 30, 2012. 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.

(d) Other long-term liabilities include $16.3 million of asset retirement obligations and $1.0 million of environmental reserves recognized in the June 30, 2012 condensed consolidated balance sheet.

We have no items that are classified as off balance sheet obligations.

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Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2011-04 Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*, or ASU 2011-04** In May 2011, the FASB issued ASU 2011-04 which amends Accounting Standards Codification, Topic 820 Fair Value Measurements and Disclosures to change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, clarify the FASB s intent about the application of existing fair value measurement requirements, and change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The provisions of ASU 2011-04 became effective for us for interim and annual periods beginning after December 15, 2011. The provisions of ASU 2011-04 impact only disclosures and we have disclosed information in accordance with the provisions of ASU 2011-04 within this filing.

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

For an in-depth discussion of our market risks, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2011Form 10-K included as Exhibit 99.2 to our Current Report on Form 8-K filed on June 14, 2012.

Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketers 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 that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations.

At December 31, 2011, we had interest rate swap agreements totaling $450.0 million, of which we had designated $425.0 million as cash flow hedges and accounted for the remaining $25.0 million under the mark-to-market method of accounting. In March 2012, we paid down a portion of the revolving credit facility and as a result, we discontinued cash flow hedge accounting on $225.0 million of our interest rate swap agreements.

At June 30, 2012, we had interest rate swap agreements extending through June 2014 totaling $150.0 million, which are designated as cash flow hedges. Based on our current operations we believe our interest rate swap agreements mitigate our interest rate risk associated with our variable-rate debt.

Effectiveness of our interest rate swap agreements designated as cash flow hedges 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 consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. Ineffective portions of changes in fair value are recognized in earnings.

At June 30, 2012, the effective weighted-average interest rate on our outstanding debt was 3.73%, taking into account our interest rate swap agreements designated as cash flow hedges totaling $150.0 million.

Based on the annualized unhedged borrowings under our credit facility of $200.0 million as of June 30, 2012, a 0.5% movement in the base rate or LIBOR rate result in an approximately $1.0 million annualized increase or decrease in interest expense.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering services, we receive fees or commodities from producers to bring the natural gas from the wellhead to the processing plant. For processing and storage 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, costless collars 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 fixed price swaps and collar arrangements to mitigate a portion of the effect pricing fluctuations may have on the value of our assets and operations. Depending on our risk management objectives, we may periodically settle a portion of these instruments prior to their maturity.

We enter into derivative financial instruments to mitigate a portion of the cash flow risk of decreased natural gas, NGL and condensate prices associated with our percent-of-proceeds arrangements and gathering operations. We also may enter into natural gas derivatives to lock in margin around our transportation or leased storage assets. Historically, there has been a strong relationship between NGL prices and crude oil prices, with some recent exceptions. Given the limited liquidity and tenor of the NGL financial market, we have historically used crude oil swaps and costless collars to mitigate a portion of our NGL price risk. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship where we utilize crude oil swaps and costless collars to mitigate NGL price exposure. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps, a portion of which are with DCP Midstream, LLC. As a result of these transactions, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk through 2016.

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

We also use commodity collar arrangements, which entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the floor price stated in the contract. Conversely, if the reference price is above the ceiling price stated in the contract, we are required to make payment at settlement to the counterparty. If the reference price is between the floor price and the ceiling price, no payment will be made at the settlement of the contract.

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

The following tables set forth additional information about our fixed price swaps, and our collar arrangements used to mitigate a portion of our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering operations, as of August 3, 2012:

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Commodity Swaps

Period		Commodity	Notional Volume - (Short)/Long Positions	Reference Price	Price Range
July 2012	December 2012	Natural Gas	(1,181) MMBtu/d	Monthly Average for Carthage Gas Daily Daily (e)	$4.34/MMBtu
July 2012	December 2014	Natural Gas	(500) MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a)	$5.06/MMBtu
July 2012	December 2014	Natural Gas	(1,000) MMBtu/d	Texas Gas Transmission Price (b)	$4.87/MMBtu
July 2012	December 2012	NGL's	(2,463) Bbls/d	Mt.Belvieu Non-TET (d)	$0.90 - $2.60/Gal
January 2013	December 2013	NGL's	(1,715) Bbls/d	Mt.Belvieu Non-TET (d)	$0.90 - $2.60/Gal
January 2014	March 2015	NGL's	(1,725) Bbls/d	Mt.Belvieu Non-TET (d)	$0.90 - $2.60/Gal
July 2012	December 2012	NGL's	(702) Bbls/d	Mt.Belvieu Non-TET (d)	$2.20/Gal
July 2012	December 2012	Crude Oil	(2,325) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$66.72 - $99.85/Bbl
January 2013	December 2013	Crude Oil	(2,250) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$67.60 - $99.85/Bbl
January 2014	December 2014	Crude Oil	(1,500) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$74.90 - $96.08/Bbl
January 2015	December 2015	Crude Oil	(1,000) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$92.00-$100.04/Bbl
January 2016	December 2016	Crude Oil	(500) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$101.30/Bbl
July 2012	December 2014	Natural Gas	500 MMBtu/d	Texas Gas Transmission Price (b)	$4.93/MMBtu
July 2012	December 2012	Crude Oil	700 Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$92.00/Bbl

(a) The Inside FERC index price for natural gas delivered into the Colorado Interstate Gas (CIG) pipeline.
(b) The Inside FERC index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.
(c) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).
(d) The average monthly OPIS price for Mt. Belvieu Non-TET.
(e) The average monthly natural gas price for Carthage Gas Daily Daily.

Commodity Collar Arrangements

Period		Commodity	Notional Volume	Reference Price	Collar Price Range
July 2012	December 2012	Crude Oil	600 Bbls/d (a)	Asian-pricing of NYMEX crude oil futures (b)	$80.00 - $97.40/Bbl
January 2013	December 2013	Crude Oil	400 Bbls/d (a)	Asian-pricing of NYMEX crude oil futures (b)	$80.00 - $96.50/Bbl

(a) Reflects separate purchased put and sold call contracts, resulting in a collar arrangement.
(b) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).

Our sensitivities for 2012 as shown in the table below are estimated based on our average estimated commodity price exposure and commodity cash flow protection activities for the calendar year 2012, and exclude the impact from non-cash mark-to-market on our commodity derivatives. We utilize crude oil and NGL derivatives to mitigate a portion of our commodity price exposure for NGLs, and show our sensitivity to changes in the relationship between the pricing of NGLs and crude oil. For fixed price natural gas and crude oil, the sensitivities are associated with our unhedged volumes. For our NGL to crude oil price relationship, the sensitivity is associated with both hedged and unhedged equity volumes.

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Commodity Sensitivities Excluding Non-Cash Mark-To-Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 1.7
Crude oil prices (a)	$ 5.00	Barrel	$ 3.6
NGL to crude oil price relationship (b)	5 percentage point change	Barrel	$ 7.2

(a) Assuming 60% NGL to crude oil price relationship. At crude oil prices outside of our collar range of approximately $80.00 to $97.40, this sensitivity decreases by $0.8 million.

(b) Assuming 60% NGL to crude oil price relationship and $90.00 /Bbl crude oil price. Generally, this sensitivity changes by $0.8 million for each $10.00/Bbl change in the price of crude oil. As crude oil prices increase from $90.00 /Bbl, we become slightly more sensitive to the change in the relationship of NGL prices to crude oil prices. As crude oil prices decrease from $90.00 /Bbl, we become less sensitive to the change in the relationship of NGL prices to crude oil prices.

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

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

We estimate the following non-cash sensitivities in 2012 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income Attributable to Partners) (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 1.1
Crude oil prices	$ 5.00	Barrel	$ 11.1
NGL prices	$ 0.10	Gallon	$ 8.4

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

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally related to the price of crude oil. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing activities through 2016.

Given the historical relationship between NGL prices and crude oil prices and the limited liquidity and tenor of the NGL financial market, we have used crude oil derivative instruments to mitigate a portion of NGL price risk. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship where we utilize crude oil swaps to mitigate NGL price exposure. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps.

Based on historical trends, we generally expect NGL prices to directionally follow changes in crude oil prices over the long-term. However, the pricing relationship between NGLs and crude oil may vary, as we believe crude oil prices will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy, whereas NGL prices are more correlated to supply and U.S. petrochemical demand. We believe that future natural gas prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production and drilling activity of exploration and production companies and imports of liquid natural gas, or LNG, from foreign locations. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also further reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall relative to demand levels.

Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our condensed consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

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The following tables set forth additional information about our derivative instruments used to mitigate a portion of our natural gas price risk associated with our Southeast Texas storage operations, as of June 30, 2012:

Inventory

Period	Commodity	Notional Volume - (Short)/Long Positions	Fair Value (millions)	Weighted Average Price
June 30, 2012	Natural Gas	6,871,747 MMBtu's	$ 14.9	$2.18/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Fair Value (millions)	Price Range
July 2012 - December 2012	Natural Gas	(28,740,000) MMBtu	$ (5.2)	$2.18-$3.34/MMBtu
January 2013 October 2013	Natural Gas	(12,000,000) MMBtu	$ (1.3)	$3.19-$3.61/MMBtu
July 2012 - December 2012	Natural Gas	26,370,000 MMBtu	$ 1.6	$2.32-$4.50/MMBtu
February 2013 - November 2013	Natural Gas	7,500,000 MMBtu	$ 0.6	$3.20-$3.77/MMBtu

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

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission s rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of June 30, 2012, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of June 30, 2012, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2012 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 17, Commitments and Contingent Liabilities, included in Item 8 of our 2011 Form 10-K included as Exhibit 99.3 to our Current Report on Form 8-K filed on June 14, 2012, which Exhibit 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 2011 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 2011 Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our condensed consolidated results of operations, financial condition and cash flows.

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Recently proposed or finalized rules imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

On April 17, 2012, the U.S. Environmental Protection Agency (EPA) approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or green completions on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require modifications to the operations of our natural gas exploration and production customers as well as our operations including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our customers could result in reduced production by those customers and thus translate into reduced demand for our services which could in turn have an adverse effect on our business and cash available for distributions.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas that we gather, process and transport.

Certain of our customers' natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate production. While the underground injection of fluids is regulated by the U.S. EPA under the Safe Drinking Water Act (SDWA), fracturing is excluded from regulation unless the injection fluid is diesel fuel. Congress has recently considered legislation that would repeal the exclusion, allowing EPA to more generally regulate fracturing, and requiring disclosure of chemicals used in the fracturing process. If enacted, such legislation could require fracturing to meet permitting and financial responsibility, siting and technical specifications relating to well construction, plugging and abandonment. EPA is also considering various regulatory programs directed at hydraulic fracturing. For example, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult for our customers to complete oil and natural gas wells in shale formations and increase their costs of compliance. In addition, the U.S. EPA is currently studying the potential adverse impact that each stage of hydraulic fracturing may have on the environment. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely.

In addition, federal agencies have recently initiated certain other regulatory initiatives or reviews of certain aspects of hydraulic fracturing that could further increase our natural gas exploration and production customer s costs and decrease their levels of production. On May 4, 2012, the federal Bureau of Land Management announced draft rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon Native American Indian and other federal lands. Moreover, in late 2011, the EPA announced that it is developing standards for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and indicated that such standards would be proposed by 2014. The adoption and implementation of rules relating to hydraulic fracturing could result in increased expenditures for our natural gas exploration and production customers, which could cause them to reduce their production and thereby result in reduced demand for our services by these customers.

Item 5. ***Other Information***

The Company adopted Accounting Standard Updates No. 2011-05 and 2011-12, Presentation of Comprehensive Income. Under the new guidance, entities are required to present total comprehensive income either in a single, continuous statement of comprehensive income or in two separate, but consecutive, statements. The retrospective application of this statement did not have a material impact on our financial condition or results of operations. The following Condensed Consolidating Statements of Comprehensive Income will be included in the financial statements of parent guarantors in the Supplementary Information Condensed Consolidating Financial Information Note to our annual financial statements:

Condensed Consolidating Statements of Comprehensive Income
Year Ended December 31, 2011 (a)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 120.8	$ 120.8	$ 173.1	$ (275.1)	$ 139.6
Other comprehensive income (loss):					
Reclassification of cash flow hedges into earnings		20.4	0.3		20.7
Net unrealized losses on cash flow hedges		(12.4)	(0.9)		(13.3)
Net unrealized losses on cash flow hedges predecessor			(1.8)		(1.8)
Other comprehensive income (loss) from consolidated subsidiaries	5.6	(2.4)		(3.2)	
Total other comprehensive income (loss)	5.6	5.6	(2.4)	(3.2)	5.6
Total comprehensive income	126.4	126.4	170.7	(278.3)	145.2
Total comprehensive income attributable to noncontrolling interests			(18.8)		(18.8)
Total comprehensive income attributable to partners	$ 126.4	$ 126.4	$ 151.9	$ (278.3)	$ 126.4

(a) The financial information for the year ended December 31, 2011 includes the results of our 100% interest in Southeast Texas and commodity derivative instruments related to the Southeast Texas storage business. These transfers of net assets between entities under common control were accounted for as if the transfers occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

Condensed Consolidating Statements of Comprehensive Income
Year Ended December 31, 2010 (b)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 91.2	$ 91.2	$ 129.4	$ (211.4)	$ 100.4
Other comprehensive income:					
Reclassification of cash flow hedges into earnings		22.4	0.5		22.9
Net unrealized losses on cash flow hedges		(18.7)			(18.7)
Other comprehensive income (loss) from consolidated subsidiaries	4.2	0.5		(4.7)	
Total other comprehensive income	4.2	4.2	0.5	(4.7)	4.2
Total comprehensive income	95.4	95.4	129.9	(216.1)	104.6
Total comprehensive income attributable to noncontrolling interests			(9.2)		(9.2)

Total comprehensive income attributable to partners	$ 95.4	$ 95.4	$ 120.7	$ (216.1)	$ 95.4

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(b) The financial information for the year ended December 31, 2010 includes the results of our 100% interest in Southeast Texas and commodity derivative instruments related to the Southeast Texas storage business. These transfers of net assets between entities under common control were accounted for as if the transfers occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statements of Comprehensive Income Year Ended December 31, 2009 (c)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
Net income	$ 6.1	$ 6.1	$ 42.3	$ (40.1)	$ 14.4
Other comprehensive income (loss):					
Reclassification of cash flow hedges into earnings		19.7	0.9		20.6
Net unrealized losses on cash flow hedges		(12.0)			(12.0)
Net unrealized losses on cash flow hedges - predecessor			(2.0)		(2.0)
Other comprehensive income (loss) from consolidated subsidiaries	6.6	(1.1)		(5.5)	
Total other comprehensive income (loss)	6.6	6.6	(1.1)	(5.5)	6.6
Total comprehensive income	12.7	12.7	41.2	(45.6)	21.0
Total comprehensive income attributable to noncontrolling interests			(8.3)		(8.3)
Total comprehensive income attributable to partners	$ 12.7	$ 12.7	$ 32.9	$ (45.6)	$ 12.7

(c) The financial information for the year ended December 31, 2009 includes the results of our 100% interest in Southeast Texas and commodity derivative instruments related to the Southeast Texas storage business. These transfers of net assets between entities under common control were accounted for as if the transfers occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

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Item 6. ***Exhibits***

Exhibit Number		Description
2.1	*	Contribution Agreement among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP dated June 25, 2012 (attached as Exhibit 2.1 to DCP Midstream Partners, LP s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 29, 2012).
3.1	*	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP (attached as Exhibit 3.4 to DCP Midstream Partners, LP s Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.2	*	First Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC (attached as Exhibit 3.6 to DCP Midstream Partners, LP s Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
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4.1	*	Third Supplemental Indenture by and among DCP Midstream Operating, LP, DCP Midstream Partners, LP and The Bank of New York Mellon Trust Company, N.A. dated June 14, 2012 (attached as Exhibit 4.1 to DCP Midstream Partners, LP s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 14, 2012).
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10.1	*	Fifteenth Amendment to the Omnibus Agreement by and among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP dated July 2, 2012 (attached as Exhibit 10.1 to DCP Midstream Partners, LP s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on July 9, 2012).
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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.
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* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on August 8, 2012.

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
(Principal Executive Officer)

By: /s/ Rose M. Robeson
Name: Rose M. Robeson
Title: Senior Vice President and Chief Financial Officer

(Principal Financial Officer)

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