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

FORM 10-Q

(Mark One)

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

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

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

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

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of November 2, 2012, there were outstanding 61,091,793 common units representing limited partner interests.

DCP MIDSTREAM PARTNERS, LP
FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2012

TABLE OF CONTENTS

Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002
Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002
Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002
Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002

Table of Contents

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

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 on budget and 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;
- the amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs;
- 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.

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

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

	September 30, 2012	December 31, 2011
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 8.4	$ 7.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.5 million and $0.3 million, respectively	72.6	108.6
Affiliates	67.8	106.2
Inventories	71.6	87.9
Unrealized gains on derivative instruments	47.3	41.2
Other	2.9	2.2
Total current assets	270.6	353.7
Property, plant and equipment, net	1,673.8	1,499.4
Goodwill	153.8	153.8
Intangible assets, net	139.0	145.3
Investments in unconsolidated affiliates	229.0	107.1
Unrealized gains on derivative instruments	37.2	6.4
Other long-term assets	14.0	11.7
Total assets	$ 2,517.4	$ 2,277.4
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 170.0	$ 231.7
Affiliates	14.1	46.8
Unrealized losses on derivative instruments	43.4	59.9
Other	68.2	42.1
Total current liabilities	295.7	380.5
Long-term debt	1,038.3	746.8
Unrealized losses on derivative instruments	13.6	32.8
Other long-term liabilities	28.3	19.0
Total liabilities	1,375.9	1,179.1
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	257.4
Common unitholders (59,179,130 and 44,848,703 units issued and outstanding, respectively)	1,124.2	654.4
General partner	(1.0)	(4.7)
Accumulated other comprehensive loss	(15.5)	(21.2)
Total partners' equity	1,107.7	885.9
Noncontrolling interests	33.8	212.4
Total equity	1,141.5	1,098.3
Total liabilities and equity	$ 2,517.4	$ 2,277.4

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 144.4	$ 227.8	$ 540.3	$ 801.7
Sales of natural gas, propane, NGLs and condensate to affiliates	161.4	268.3	549.1	851.0
Transportation, processing and other	36.2	33.1	102.5	99.2
Transportation, processing and other to affiliates	8.8	9.7	28.2	23.0
(Losses) gains from commodity derivative activity, net	(11.1)	54.1	17.0	29.0
(Losses) gains from commodity derivative activity, net — affiliates	(8.8)	0.6	33.1	(0.8)
Total operating revenues	330.9	593.6	1,270.2	1,803.1
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	247.9	372.0	761.0	1,150.3
Purchases of natural gas, propane and NGLs from affiliates	20.1	77.0	212.4	314.0
Operating and maintenance expense	35.7	36.7	91.7	91.3
Depreciation and amortization expense	14.8	25.9	49.6	74.9
General and administrative expense	3.7	4.7	11.9	13.2
General and administrative expense — affiliates	7.4	7.3	22.1	22.0
Other income	(0.1)	(0.2)	(0.4)	(0.4)
Total operating costs and expenses	329.5	523.4	1,148.3	1,665.3
Operating income	1.4	70.2	121.9	137.8
Interest expense	(8.1)	(8.6)	(31.8)	(25.0)
Earnings from unconsolidated affiliates	8.9	6.9	16.6	17.1
Income before income taxes	2.2	68.5	106.7	129.9
Income tax expense	(0.3)	(0.4)	(1.0)	(0.9)
Net income	1.9	68.1	105.7	129.0
Net (income) loss attributable to noncontrolling interests	(0.6)	0.4	(2.0)	(12.8)
Net income attributable to partners	1.3	68.5	103.7	116.2
Net income attributable to predecessor operations	—	(2.2)	(2.6)	(14.3)
General partner’s interest in net income	(10.8)	(6.8)	(29.4)	(18.5)
Net (loss) income allocable to limited partners	$ (9.5)	$ 59.5	$ 71.7	$ 83.4
Net (loss) income per limited partner unit — basic	$ (0.16)	$ 1.35	$ 1.37	$ 1.93
Net (loss) income per limited partner unit — diluted	$ (0.16)	$ 1.35	$ 1.36	$ 1.93
Weighted-average limited partner units outstanding — basic	58.7	44.1	52.5	43.2
Weighted-average limited partner units outstanding — diluted	58.7	44.2	52.6	43.2

See accompanying notes to condensed consolidated financial statements.

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Millions)			
Net income	$ 1.9	$ 68.1	$ 105.7	$ 129.0
Other comprehensive income (loss):				
Reclassification of cash flow hedge losses into earnings	0.6	5.2	9.9	15.6
Net unrealized gains (losses) on cash flow hedges	0.7	(5.5)	—	(9.8)
Net unrealized losses on cash flow hedges - predecessor	—	(0.3)	(0.6)	(0.7)
Total other comprehensive income (loss)	1.3	(0.6)	9.3	5.1
Total comprehensive income	3.2	67.5	115.0	134.1
Total comprehensive (income) loss attributable to noncontrolling interests	(0.6)	0.4	(2.0)	(12.8)
Total comprehensive income attributable to partners	$ 2.6	$ 67.9	$ 113.0	$ 121.3

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30, 2012	2011
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 105.7	$ 129.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	49.6	74.9
Earnings from unconsolidated affiliates	(16.6)	(17.1)
Distributions from unconsolidated affiliates	15.9	19.8
Net unrealized gains on derivative instruments	(18.9)	(47.3)
Other, net	1.5	3.2
Change in operating assets and liabilities, which provided (used) cash net of effects of acquisitions:		
Accounts receivable	83.4	53.2
Inventories	16.3	(2.8)
Accounts payable	(95.7)	(26.2)
Accrued interest	11.6	2.2
Other current assets and liabilities	7.4	(5.3)
Other long-term assets and liabilities	(1.4)	(2.6)
Net cash provided by operating activities	158.8	181.0
INVESTING ACTIVITIES:		
Capital expenditures	(152.5)	(98.5)
Acquisitions, net of cash acquired	(375.4)	(60.6)
Acquisition of unconsolidated affiliate	(29.8)	(114.3)
Investments in unconsolidated affiliates	(86.3)	(6.8)
Return of investment from unconsolidated affiliate	1.0	1.6
Proceeds from sale of assets	0.2	0.2
Net cash used in investing activities	(642.8)	(278.4)
FINANCING ACTIVITIES:		
Proceeds from debt	1,353.4	832.0
Payments of debt	(1,062.0)	(754.0)
Payment of deferred financing costs	(3.5)	(0.1)
Excess purchase price over acquired assets	(110.2)	(35.7)
Proceeds from issuance of common units, net of offering costs	445.2	152.0
Net change in advances to predecessor from DCP Midstream, LLC	(11.5)	14.6
Distributions to unitholders and general partner	(128.7)	(97.5)
Distributions to noncontrolling interests	(4.8)	(26.8)
Contributions from DCP Midstream, LLC	6.9	9.1
Net cash provided by financing activities	484.8	93.6
Net change in cash and cash equivalents	0.8	(3.8)
Cash and cash equivalents, beginning of period	7.6	6.7
Cash and cash equivalents, end of period	$ 8.4	$ 2.9

See accompanying notes to condensed consolidated financial statements.

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

	Partners' Equity					
	Predecessor Equity	Common Unitholders	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
Issuance of units for Mont Belvieu fractionators	—	60.0	—	—	—	60.0
Deficit purchase price under carrying value of acquired net assets for Southeast Texas and East Texas	—	35.8	—	(4.2)	—	31.6
Excess purchase price over carrying value of acquired net assets for Mont Belvieu fractionators	—	(170.2)	—	—	—	(170.2)
Issuance of 11,031,691 common units	—	445.2	—	—	—	445.2
Equity-based compensation	—	(0.4)	—	—	—	(0.4)
Distributions to unitholders and general partner	—	(103.0)	(25.7)	—	—	(128.7)
Distributions to noncontrolling interests	—	—	—	—	(4.8)	(4.8)
Contributions from DCP Midstream, LLC	—	10.2	—	—	—	10.2
Comprehensive income:						
Net income attributable to predecessor operations	2.6	—	—	—	—	2.6
Net income	—	71.7	29.4	—	2.0	103.1
Reclassification of cash flow hedges into earnings	—	—	—	9.9	—	9.9
Net unrealized losses on cash flow hedges	(0.6)	—	—	—	—	(0.6)
Total comprehensive income	2.0	71.7	29.4	9.9	2.0	115.0
Balance, September 30, 2012	$ —	$ 1,124.2	$ (1.0)	$ (15.5)	$ 33.8	$1,141.5

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	19.0	—	—	—	—	19.0
Acquisition of Southeast Texas	(114.3)	—	—	—	—	(114.3)
Excess purchase price over acquired assets	—	(34.8)	—	(0.9)	—	(35.7)
Issuance of 3,941,667 common units	—	152.2	—	—	—	152.2
Equity-based compensation	—	2.9	—	—	—	2.9
Distributions to DCP Midstream, LLC	—	(2.6)	—	—	—	(2.6)
Distributions to unitholders and general partner	—	(80.5)	(17.0)	—	—	(97.5)
Distributions to noncontrolling interests	—	—	—	—	(26.8)	(26.8)
Contributions from DCP Midstream, LLC	—	—	—	—	9.1	9.1
Comprehensive income:						
Net income attributable to predecessor operations	14.3	—	—	—	—	14.3
Net income	—	83.4	18.5	—	12.8	114.7
Reclassification of cash flow hedges into earnings	—	—	—	15.6	—	15.6
Net unrealized losses on cash flow hedges	(0.7)	—	—	(9.8)	—	(10.5)
Total comprehensive income	13.6	83.4	18.5	5.8	12.8	134.1
Balance, September 30, 2011	$ 256.1	$ 672.8	$ (4.9)	$ (22.8)	$ 215.2	$1,116.4

See accompanying notes to condensed consolidated financial statements.

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

1. Description of Business and Basis of Presentation

DCP Midstream Partners, LP, with its consolidated subsidiaries, or us, we or our 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 the remaining 49.9% was acquired in January 2012, and the Crossroads system was acquired in July 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, the DJ Basin NGL fractionators and our minority ownership interests in the Mont Belvieu fractionators acquired in July 2012), 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. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by Phillips 66. 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 nine months ended September 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 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 acquisition 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 interest in an approximately 11-mile residue gas pipeline, or CrossPoint Pipeline, LLC, which we have accounted for as an unconsolidated affiliate using the equity method.

Table of Contents

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

We have accounted for the Crossroads business combination based on estimates of the fair value of assets acquired and liabilities assumed, including: property, plant and equipment; the equity investment in CrossPoint Pipeline, LLC; a liability for a firm transportation agreement which expires in 2015; and a gas purchase agreement under which a portion of those firm transportation payments are recoverable. Expected cash payments and receipts have been recorded at their estimated fair value and are included in other current liabilities, other long-term liabilities, and accounts receivable in our September 30, 2012 condensed consolidated balance sheet. The purchase price allocation is preliminary and is based on initial estimates of fair values at the date of the acquisition. We are currently evaluating the preliminary purchase price allocation, which will be adjusted as additional information relative to the fair value of assets and liabilities becomes available. This allocation may change in subsequent financial statements pending the final estimates of fair value. The preliminary purchase price allocation as of September 30, 2012 is as follows:

	September 30, 2012
	(Millions)
Aggregate consideration	$ 63.0
Accounts receivable	$ 4.2
Property, plant and equipment	63.1
Investments in unconsolidated affiliates	6.1
Other current liabilities	(4.1)
Other long-term liabilities	(6.3)
Total preliminary purchase price allocation	$ 63.0

The results of operations for acquisitions accounted for as a business combination are included in our results subsequent to the date of acquisition. Accordingly, for the three and nine months ended September 30, 2012 total operating revenues of $8.5 million and net income attributable to the Partnership of $0.8 million associated with Crossroads, are included in the condensed consolidated statement of operations. Pro forma information is presented for comparative periods prior to the date of acquisition; however, comparative periods in the condensed consolidated financial statements are not adjusted to include the results of the acquisition.

The following tables present unaudited pro forma information for the condensed consolidated statement of operations for the nine months ended September 30, 2012 and 2011 and the three months ended September 30, 2011, as if the acquisition of Crossroads had occurred at the beginning of the earliest period presented.

	Nine Months Ended September 30, 2012		
	DCP Midstream Partners, LP	Acquisition of Crossroads (a)	DCP Midstream Partners, LP Pro Forma
		(Millions)	
Total operating revenues	$ 1,270.2	$ 27.0	$ 1,297.2
Net income attributable to partners	$ 103.7	$ 1.6	$ 105.3
Less:			
Net income attributable to predecessor operations	(2.6)	—	(2.6)
General partner unitholders interest in net income	(29.4)	—	(29.4)
Net income allocable to limited partners	$ 71.7	$ 1.6	$ 73.3
Net income per limited partner unit — basic	$ 1.37	$ 0.03	$ 1.40
Net income per limited partner unit — diluted	$ 1.36	$ 0.03	$ 1.39

(a) The nine months ended September 30, 2012, includes the financial results of Crossroads for the period from January 1, 2012 through July 2, 2012.

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

	Nine Months Ended September 30, 2011		
	DCP Midstream Partners, LP	Acquisition of Crossroads	DCP Midstream Partners, LP Pro Forma
		(Millions)	
Total operating revenues	$ 1,803.1	$ 91.3	$ 1,894.4
Net income attributable to partners	$ 116.2	$ 3.4	$ 119.6
Less:			
Net income attributable to predecessor operations	(14.3)	—	(14.3)
General partner unitholders interest in net income	(18.5)	—	(18.5)
Net income allocable to limited partners	$ 83.4	$ 3.4	$ 86.8
Net income per limited partner unit — basic and diluted	$ 1.93	$ 0.08	$ 2.01

	Three Months Ended September 30, 2011		
	DCP Midstream Partners, LP	Acquisition of Crossroads	DCP Midstream Partners, LP Pro Forma
		(Millions)	
Total operating revenues	$ 593.6	$ 28.0	$ 621.6
Net income attributable to partners	$ 68.5	$ 0.7	$ 69.2
Less:			
Net income attributable to predecessor operations	(2.2)	—	(2.2)
General partner unitholders interest in net income	(6.8)	—	(6.8)
Net income allocable to limited partners	$ 59.5	$ 0.7	$ 60.2
Net income per limited partner unit — basic and diluted	$ 1.35	$ 0.02	$ 1.37

The supplemental pro forma total operating revenues for the nine months ended September 30, 2012 was adjusted to eliminate $5.4 million related to a contractual gas processing arrangement between us and Crossroads during the period.

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

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 $170.2 million excess purchase price over the historical basis of the net assets acquired was recorded as a decrease in common unitholders' equity. The minority ownership interests include a 12.5% interest in the Enterprise fractionator, which is operated by Enterprise Products Partners L.P., and a 20% interest in the Mont Belvieu 1 fractionator, which is operated by ONEOK Partners. Accordingly, we have accounted for the results of the minority ownership interests in the Mont Belvieu fractionators prospectively from the date of acquisition. The Mont Belvieu fractionators are accounted for as unconsolidated affiliates using the equity method.

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 in the Texas Express Pipeline joint venture, representing our proportionate share of the investment through the closing date, 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 as of September 30, 2012, 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 consideration of $240.0 million plus $20.7 million in working capital and other customary purchase price adjustments. $192.0 million of the consideration 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. The $8.9 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. 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 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.

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

Combined Financial Information

The results of our 100% interest in Southeast Texas are included in the condensed consolidated balance sheets as of September 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
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.

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

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

Three Months Ended September 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	$ 290.4	$ 205.7	$ —	$ 496.1
Transportation, processing and other	40.8	2.0	—	42.8
Gains from commodity derivative activity, net	52.1	2.6	—	54.7
Total operating revenues	383.3	210.3	—	593.6
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	257.3	191.7	—	449.0
Operating and maintenance expense	31.5	5.2	—	36.7
Depreciation and amortization expense	20.6	5.3	—	25.9
General and administrative expense	9.4	2.6	—	12.0
Other income	(0.2)	—	—	(0.2)
Total operating costs and expenses	318.6	204.8	—	523.4
Operating income	64.7	5.5	—	70.2
Interest expense, net	(8.6)	—	—	(8.6)
Earnings from unconsolidated affiliates	10.0	—	(3.1)	6.9
Income before income taxes	66.1	5.5	(3.1)	68.5
Income tax expense	(0.2)	(0.2)	—	(0.4)
Net income	65.9	5.3	(3.1)	68.1
Net loss attributable to noncontrolling interests	0.4	—	—	0.4
Net income attributable to partners	$ 66.3	$ 5.3	$ (3.1)	$ 68.5

(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%.

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

Nine Months Ended September 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	$ 1,043.2	$ 609.5	$ —	$ 1,652.7
Transportation, processing and other	114.9	7.3	—	122.2
Gains from commodity derivative activity, net	24.5	3.7	—	28.2
Total operating revenues	1,182.6	620.5	—	1,803.1
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	906.6	557.7	—	1,464.3
Operating and maintenance expense	77.3	14.0	—	91.3
Depreciation and amortization expense	60.6	14.3	—	74.9
General and administrative expense	27.0	8.2	—	35.2
Other income	(0.4)	—	—	(0.4)
Total operating costs and expenses	1,071.1	594.2	—	1,665.3
Operating income	111.5	26.3	—	137.8
Interest expense, net	(25.0)	—	—	(25.0)
Earnings from unconsolidated affiliates	28.6	—	(11.5)	17.1
Income before income taxes	115.1	26.3	(11.5)	129.9
Income tax expense	(0.4)	(0.5)	—	(0.9)
Net income	114.7	25.8	(11.5)	129.0
Net income attributable to noncontrolling interests	(12.8)	—	—	(12.8)
Net income attributable to partners	$ 101.9	$ 25.8	$ (11.5)	$ 116.2

(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. In July 2012, in conjunction with our acquisition of the minority interests in the Mont Belvieu fractionators, we increased the annual fee we pay to DCP Midstream, LLC by $0.2 million. As a result of these transactions, the annual fee we pay to DCP Midstream, LLC will be $28.1 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Millions)			
Omnibus Agreement	$ 7.0	$ 2.6	$18.4	$ 7.6
Other fees — DCP Midstream, LLC	0.3	4.7	3.5	14.2
Total — DCP Midstream, LLC	$ 7.3	$ 7.3	$21.9	$21.8

In addition to the Omnibus Agreement, we incurred other general and administrative fees with DCP Midstream, LLC of $0.3 million for each of the three months ended September 30, 2012 and 2011, and $1.0 million for each of the nine months ended September 30, 2012 and 2011. These amounts include allocated expenses, including professional services, insurance and internal audit. For the nine months ended September 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 nine months ended September 30, 2011, Southeast Texas incurred $2.5 million and $7.5 million, respectively, in general and administrative expenses directly from DCP Midstream, LLC. For the three and nine months ended September 30, 2011, East Texas incurred $1.9 million and $5.7 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 nine months ended September 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 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 $1.2 million and $3.5 million for the three months ended September 30, 2012 and 2011, respectively, and $6.4 million and $9.1 million for the nine months ended September 30, 2012 and 2011, respectively. DCP Midstream, LLC made capital contributions to Southeast Texas for capital projects of $2.1 million and $3.7 million for the three and nine months ended September 30, 2012. As of September 30, 2012, $1.2 million and $2.1 million of the contributions to East Texas and Southeast Texas, respectively, are recorded as receivables from affiliates in the condensed consolidated balance sheet.

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.

As a result of a downstream outage, certain of our assets were required to curtail NGL production during 2012. DCP Midstream, LLC has reimbursed us for the impact of the curtailment and accordingly, we have recorded $2.5 million to sales of natural gas, propane, NGLs and condensate to affiliates and $0.2 million to transportation, processing and other to affiliates in the condensed consolidated statements of operations for the three and nine months ended September 30, 2012.

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 on 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 condensed 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 condensed 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 $0.2 million and $0.7 million during the three and nine months ended September 30, 2012, respectively, and $0.1 million and $0.3 million during the three and nine months ended September 30, 2011, which are included in operating and maintenance expense in the condensed consolidated statements of operations.

DCP Midstream, LLC has issued parental guarantees, totaling $25.0 million as of September 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.

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

Spectra Energy

We had propane supply agreements with Spectra Energy that expired 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.

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$161.3	$258.0	$539.9	$809.5
Transportation, processing and other	$ 8.8	$ 7.9	$ 25.9	$ 17.4
Purchases of natural gas, propane and NGLs	$ 20.1	$ 33.6	$ 95.6	$132.2
(Losses) gains from commodity derivative activity, net	$ (8.8)	$ 0.6	$ 33.1	$ (0.8)
General and administrative expense	$ 7.3	$ 7.3	$ 21.9	$ 21.8
Spectra Energy:				
Purchases of natural gas, propane and NGLs	$ —	$ 41.8	$113.1	$173.5
ConocoPhillips (a):				
Sales of natural gas, propane, NGLs and condensate	$ —	$ 10.3	$ 9.0	$ 41.5
Transportation, processing and other	$ —	$ 1.8	$ 2.3	$ 5.6
Purchases of natural gas, propane and NGLs	$ —	$ 1.6	$ 1.3	$ 5.2
General and administrative expense	$ —	$ —	$ 0.1	$ 0.2
Phillips 66 (a):				
Sales of natural gas, propane, NGLs and condensate	$ 0.1	$ —	$ 0.2	$ —
General and administrative expense	$ 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:

	September 30, 2012	December 31, 2011
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 67.4	$ 100.0
Accounts payable	$ 14.1	$ 22.6
Unrealized gains on derivative instruments — current	$ 44.8	$ 0.6
Unrealized gains on derivative instruments — long-term	$ 30.9	$ —
Unrealized losses on derivative instruments — current	$ (21.5)	$ (0.6)
Unrealized losses on derivative instruments — long-term	$ (1.1)	$ —
Spectra Energy:		
Accounts receivable	$ 0.3	$ 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	$ 0.1	$ —
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:

	September 30, 2012	December 31, 2011
	(Millions)	
Natural gas	$ 15.7	$ 25.6
NGLs	55.9	62.3
Total inventories	$ 71.6	$ 87.9

We 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 $0.2 million and $19.3 million in lower of cost or market adjustments during the three and nine months ended September 30, 2012, respectively. We recognized $1.9 million and $2.5 million in lower of cost or market adjustments during the three and nine months ended September 30, 2011, respectively.

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	September 30, 2012	December 31, 2011
		(Millions)	
Gathering and transmission systems	20 — 50 Years	$ 1,307.5	$ 1,211.9
Processing, storage, and terminal facilities	35 — 60 Years	820.1	742.8
Other	3 — 30 Years	24.4	23.1
Construction work in progress		261.7	218.3
Property, plant and equipment		2,413.7	2,196.1
Accumulated depreciation		(739.9)	(696.7)
Property, plant and equipment, net		$ 1,673.8	$ 1,499.4

Interest capitalized on construction projects for the three months ended September 30, 2012 and 2011 was $1.9 million and $0.2 million, respectively, and for the nine months ended September 30, 2012 and 2011 was $4.9 million and $0.7 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 and $23.8 million reduction in depreciation expense for the three and nine months ended September 30, 2012, respectively, 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 $0.20 and $0.45 for the three and nine months ended September 30, 2012, respectively.

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 $12.7 million and $23.8 million for the three months ended September 30, 2012 and 2011, respectively, and $43.3 million and $68.6 million for the nine months ended September 30, 2012 and 2011, respectively.

Asset Retirement Obligations — As of September 30, 2012, we had asset retirement obligations of $16.6 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 September 30, 2012, accretion expense was $0.3 million, and for the nine months ended September 30, 2012, accretion benefit was $0.1 million. For the three and nine months ended September 30, 2011, accretion expense was $0.2 million and $0.5 million, respectively.

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:

	Nine Months Ended September 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 September 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.

We performed our annual goodwill assessment during the quarter at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. As a result of our assessment, we concluded that the entire amount of goodwill disclosed on the condensed consolidated balance sheet is recoverable. We primarily used a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

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:

	September 30, 2012	December 31, 2011
	(Millions)	
Gross carrying amount	$ 164.3	$ 164.3
Accumulated amortization	(25.3)	(19.0)
Intangible assets, net	$ 139.0	$ 145.3

We recorded amortization expense of $2.1 million for each of the three months ended September 30, 2012 and 2011, and $6.3 million for each of the nine months ended September 30, 2012 and 2011, respectively. As of September 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	$ 2.1
2013	8.4
2014	8.4
2015	8.4
2016	8.4
Thereafter	103.3
Total	$ 139.0

8. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of September 30, 2012	Carrying Value as of December 31, 2011
		(Millions)	
Discovery Producer Services LLC	40%	$ 159.5	$ 106.9
Texas Express Pipeline	10%	33.0	—
Mont Belvieu Enterprise Fractionator	12.5%	16.0	—
Mont Belvieu 1 Fractionator	20%	14.0	—
CrossPoint Pipeline, LLC	50%	6.3	—
Other	50%	0.2	0.2
Total investments in unconsolidated affiliates		$ 229.0	$ 107.1

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $30.8 million and $32.6 million at September 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.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu 1 of $5.7 million at September 30, 2012, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Mont Belvieu 1.

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Millions)			
Discovery Producer Services LLC	$3.8	$ 6.9	$11.5	$17.1
Mont Belvieu Enterprise Fractionator	2.7	—	2.7	—
Mont Belvieu 1 Fractionator	2.3	—	2.3	—
CrossPoint Pipeline, LLC	0.1	—	0.1	—
Total earnings from unconsolidated affiliates	$8.9	$ 6.9	$16.6	$17.1

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

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Millions)			
Statements of operations:				
Operating revenue	$90.8	$55.2	$173.9	$158.7
Operating expenses	$48.6	$39.5	$115.0	$120.5
Net income	$42.2	$15.7	$ 58.4	$ 38.2

	September 30, 2012	December 31, 2011
	(Millions)	
Balance sheets:		
Current assets	$ 90.9	$ 38.1
Long-term assets	1,043.7	359.9
Current liabilities	(148.3)	(20.4)
Long-term liabilities	(42.5)	(28.5)
Net assets	$ 943.8	$ 349.1

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.

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

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

are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

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

Interest Rate Derivative Assets and Liabilities

We 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.

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

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

	September 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)	$ —	$ 26.1	$21.2	$ 47.3	$ —	$ 40.1	$ 1.1	$ 41.2
Long-term assets:								
Commodity derivatives (b)	$ —	$ 7.9	$29.3	$ 37.2	$ —	$ 5.4	$ 1.0	$ 6.4
Current liabilities (c):								
Commodity derivatives	$ —	$(39.1)	$ (0.2)	$ (39.3)	$ —	$(43.1)	$ (0.7)	$ (43.8)
Interest rate derivatives	$ —	$ (4.1)	$ —	$ (4.1)	$ —	$(16.1)	$ —	$ (16.1)
Long-term liabilities (d):								
Commodity derivatives	$ —	$(10.5)	$ (0.2)	$ (10.7)	$ —	$(27.5)	$ (0.3)	$ (27.8)
Interest rate derivatives	$ —	$ (2.9)	$ —	$ (2.9)	$ —	$ (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.

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 nine months ended September 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.

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 September 30, 2012 (a):				
Beginning balance	$ 43.6	$ 35.5	$ (0.4)	$ (0.3)
Net realized and unrealized (losses) gains included in earnings (d)	(2.2)	(6.2)	0.1	0.1
Transfers into Level 3 (c)	—	—	—	—
Transfers out of Level 3 (c)	(13.3)	—	—	—
Settlements	(6.9)	—	0.1	—
Ending balance	$ 21.2	$ 29.3	$ (0.2)	$ (0.2)
Net unrealized gains (losses) still held included in earnings (d)	$ 2.6	$ (6.2)	$ (0.1)	$ 0.1
Three months ended September 30, 2011 (b):				
Beginning balance	$ 0.6	$ 0.3	$ (1.2)	$ (0.3)
Net realized and unrealized gains (losses) included in earnings (d)	1.2	2.4	(2.1)	0.3
Transfers into Level 3 (c)	—	—	—	—
Transfers out of Level 3 (c)	—	(2.5)	—	—
Settlements	(0.4)	—	2.6	—
Ending balance	$ 1.4	$ 0.2	$ (0.7)	$ —
Net unrealized gains (losses) still held included in earnings (d)	$ 1.0	$ —	$ (0.3)	$ 0.3

(a) There were no purchases, issuances and sales of derivatives for the three months ended September 30, 2012.
(b) There were no purchases, issuances and sales of derivatives for the three months ended September 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.

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)			
Nine months ended September 30, 2012 (a):				
Beginning balance	$ 1.1	$ 1.0	$ (0.7)	$ (0.3)
Net realized and unrealized gains included in earnings (d)	9.2	1.6	0.8	0.1
Transfers into Level 3 (c)	—	—	—	—
Transfers out of Level 3 (c)	—	—	—	—
Settlements	(1.9)	—	0.4	—
Purchases	12.8	26.7	(0.7)	—
Ending balance	$ 21.2	$ 29.3	$ (0.2)	$ (0.2)
Net unrealized gains still held included in earnings (d)	$ 8.2	$ 1.6	$ 0.5	$ 0.1
Nine months ended September 30, 2011 (b):				
Beginning balance	$ 0.3	$ 0.3	$ (0.1)	$ (0.5)
Net realized and unrealized gains (losses) included in earnings (d)	1.4	1.0	(0.7)	0.5
Transfers into Level 3 (c)	—	—	—	—
Transfers out of Level 3 (c)	—	(1.1)	—	—
Settlements	(0.3)	—	0.1	—
Ending balance	$ 1.4	$ 0.2	$ (0.7)	$ —
Net unrealized gains (losses) still held included in earnings (d)	$ 1.4	$ (0.1)	$ (0.7)	$ 0.3

(a) There were no issuances and sales of derivatives for the nine months ended September 30, 2012.
(b) There were no purchases, issuances and sales of derivatives for the nine months ended September 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	$ 49.1	$0.34-$2.02	Per gallon
Natural Gas	$ 1.4	$3.74-$4.39	Per MMBtu
Liabilities			
NGLs	$ —	$ —	Per gallon
Natural Gas	$ (0.4)	$3.90-$4.39	Per MMBtu

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 $300.0 million as of September 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 $371.6 million, respectively, as of September 30, 2012. The carrying and fair values of the 3.25% Senior Notes are $250.0 million and $257.9 million, respectively, as of September 30, 2012. The carrying value of the 3.25% Senior Notes as of December 31, 2011 was $250.0 million, which approximated fair value. Each of the carrying and fair values of the term loan facility are $140.0 million as of September 30, 2012. 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.

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

10. Debt

Long-term debt was as follows:

	September 30, 2012	December 31, 2011
	(Millions)	
Credit Agreement		
Revolving credit facility, weighted-average variable interest rate of 1.48% and 1.69%, respectively, due November 10, 2016 (a)	$ 300.0	$ 497.0
Term Loan Agreement		
Term loan facility, variable interest rate of 1.62%, due July 2, 2014	140.0	—
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	$ 1,038.3	$ 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 2.84% on the $300.0 million of outstanding debt under our revolving credit facility as of September 30, 2012. $450.0 million of debt was swapped to a fixed-rate obligation with effective fixed-rates ranging from 2.94% to 5.19%, for a net effective rate of 4.86% on the $497.0 million of outstanding debt under our revolving credit facility as of December 31, 2011.

Credit Agreement

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

At September 30, 2012 and December 31, 2011, we had $1.0 million of letters of credit issued and outstanding under the Credit Agreement. As of September 30, 2012, the unused capacity under the revolving credit facility was $699.0 million, of which approximately $685.3 million was available for general working capital purposes.

Our borrowing capacity is limited at September 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 following the consummation of qualifying acquisitions, not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated.

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, 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 Agreements

On July 2, 2012, we entered into a 2-year Term Loan Agreement and borrowed $140.0 million (the "$140 million Term Loan") to fund the cash portion of the acquisition of the Mont Belvieu fractionators. The $140 million Term Loan will mature on July 2, 2014. Effective November 1, 2012, the proceeds of any subsequent indebtedness issued with a maturity date after July 2, 2014 must first be used to prepay the $140 million Term Loan. Indebtedness under the $140 million 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 $140 million 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 $140 million Term Loan Agreement) consistent with our Credit Agreement. On January 2, 2013 and July 2, 2013, one-time payments of 0.125% and 0.20%, respectively, on the outstanding principal amount of the $140 million Term Loan are required.

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.

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

	Debt Maturities (Millions)
2012	$ —
2013	—
2014	140.0
2015	250.0
Thereafter	650.0
	1,040.0
Unamortized discount	(1.7)
Total	$1,038.3

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

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.

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. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices, however there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. During 2012, the relationship of NGLs to crude oil has been lower than historical relationships, however a significant amount of our NGL hedges in 2012 and 2013 are direct product hedges. 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, including fixed price sales. 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 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.

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 the forecasted purchase of natural gas in June, July and August 2013, 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 $2.8 million as of September 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. $300.0 million of swap agreements settled in Q2 2012.

At September 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.

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

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 condensed 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.

At September 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 $4.8 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 September 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 September 30, 2012, we had $27.4 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 September 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 September 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 $24.2 million.

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

As of September 30, 2012, we had $150.0 million of individual interest rate swap instruments that were in a net liability position of $7.0 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.

Unconsolidated Affiliates

Discovery Producer Services LLC, one of our unconsolidated affiliates, entered into agreements with a pipe vendor denominated in a foreign currency in connection with the expansion of 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

DCP Midstream, LLC had issued and outstanding parental guarantees totaling $25.0 million in favor of certain counterparties to our commodity derivative instruments. These parental guarantees reduce the amount of cash we may be required to post as collateral. As of September 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:

	September 30, 2012	December 31, 2011
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (5.4)	$ (1.8)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(10.1)	(19.4)
Total AOCI	$ (15.5)	$ (21.2)

Table of Contents

The fair value of our derivative instruments that are designated as hedging instruments and 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	September 30, 2012	December 31, 2011
	(Millions)	
Derivative Assets Designated as Hedging Instruments:		
Commodity derivatives:		
Unrealized gains on derivative instruments — current	$ —	$ —
Unrealized gains on derivative instruments — long-term	—	—
	$ —	$ —
Interest rate derivatives:		
Unrealized gains on derivative instruments — current	$ —	$ —
Unrealized gains on derivative instruments — long-term	—	—
	$ —	$ —
Derivative Assets Not Designated as Hedging Instruments:		
Commodity derivatives:		
Unrealized gains on derivative instruments — current	$ 47.3	$ 41.2
Unrealized gains on derivative instruments — long-term	37.2	6.4
	$ 84.5	$ 47.6
Interest rate derivatives:		
Unrealized gains on derivative instruments — current	$ —	$ —
Unrealized gains on derivative instruments — long-term	—	—
	$ —	$ —

Balance Sheet Line Item	September 30, 2012	December 31, 2011
	(Millions)	
Derivative Liabilities Designated as Hedging Instruments:		
Commodity derivatives:		
Unrealized losses on derivative instruments — current	$ (2.8)	$ —
Unrealized losses on derivative instruments — long-term	—	(2.6)
	$ (2.8)	$ (2.6)
Interest rate derivatives:		
Unrealized losses on derivative instruments — current	$ (4.1)	$ (15.7)
Unrealized losses on derivative instruments — long-term	(2.9)	(5.0)
	$ (7.0)	$ (20.7)
Derivative Liabilities Not Designated as Hedging Instruments:		
Commodity derivatives:		
Unrealized losses on derivative instruments — current	$ (36.5)	$ (43.8)
Unrealized losses on derivative instruments — long-term	(10.7)	(25.2)
	$ (47.2)	$ (69.0)
Interest rate derivatives:		
Unrealized losses on derivative instruments — current	$ —	$ (0.4)
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 September 30,								
	2012	2011	2012	2011		2012	2011		
	(Millions)								(Millions)
Interest rate derivatives	$ (0.4)	$ (5.3)	$ (0.6)	$ (5.1)	(a)	$ —	$ (0.1)	(a)	$ (3.2)
Commodity derivatives	$ 0.6	$ (0.2)	$ —	$ (0.1)	(b)	$ —	$ —	(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 three months ended September 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.

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
	Nine Months Ended September 30,								
	2012	2011	2012	2011		2012	2011		
	(Millions)								(Millions)
Interest rate derivatives	$ (0.6)	$ (9.5)	$ (9.9)	$ (15.4)	(a)	$ (2.1)	$ (0.2)	(a)(d)	$ (3.2)
Commodity derivatives	$ —	$ (0.3)	$ —	$ (0.2)	(b)	$ (0.1)	$ —	(c)	$ —

(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 nine months ended September 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) For the nine months ended September 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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Millions)			
Third party:				
Realized	$ (3.9)	$ (6.2)	$ 7.2	$(22.1)
Unrealized	(7.2)	60.3	9.8	51.1
(Losses) gains from commodity derivative activity, net	$ (11.1)	$ 54.1	$17.0	$ 29.0
Affiliates:				
Realized	$ 6.9	$ (0.3)	$23.6	$ 1.1
Unrealized	(15.7)	0.9	9.6	(1.9)
(Losses) gains from commodity derivative activity, net — affiliates	$ (8.8)	$ 0.6	$33.2	$ (0.8)

Interest Rate Derivatives: Statements of Operations Line Item	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Millions)			
Third party:				
Realized losses	$ (0.7)	$ (1.2)	$(7.0)	$(3.5)
Unrealized gains	0.6	1.3	6.9	4.1
Interest (losses) gains	$ (0.1)	$ 0.1	$(0.1)	$ 0.6

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

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.

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

	September 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	(170,759)	(240,000)	(788,429)	605,000
2013	(927,310)	(6,865,000)	(700,975)	10,072,500
2014	(547,500)	(365,000)	(629,625)	(900,000)
2015	(365,000)	—	(155,250)	—
2016	(183,000)	—	—	—

	September 30, 2011			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net Long (Short) Position (MMBtu)	Net Short Position (Bbls)	Net Long Position (MMbtu)
2011	(87,058)	3,278,700	(379,887)	2,477,500
2012	(904,171)	(22,686,000)	(145,082)	13,800,000
2013	(947,249)	1,635,000	—	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 September 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.

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

In July 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 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 allows us to issue additional partnership equity and debt securities. As of September 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 $234.0 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.

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

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.

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 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 months ended September 30, 2012, we issued 554,589 of our common units pursuant to the equity distribution agreement, and received proceeds of $23.3 million, net of commissions and offering costs of $0.6 million. During the nine months ended September 30, 2012, we issued 893,389 of our common units pursuant to the equity distribution agreement, and received proceeds of $37.4 million, net of commissions and offering costs of $0.9 million.

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 September 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)
August 14, 2012	$ 0.6700	$ 49.4
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 26,466 and 74,299 equivalent units during the three months ended September 30, 2012 and 2011, respectively, and 35,908 and 61,573 equivalent units during the nine months ended September 30, 2012 and 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

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

may provide some protection to us for any breach of the representations, warranties and covenants made by the sellers in the Acquisition. In August 2012 we entered into a Settlement Agreement with the Claimants, in which the Claimants have agreed that if an award is issued to the Claimants in the arbitration, the Claimants will not attempt to recover such an award from us. 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 of 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.

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

Indemnification — DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors.

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, the DJ Basin NGL fractionators in Colorado, our 12.5% interest in the Mont Belvieu Enterprise fractionator, and our 20% interest in the Mont Belvieu 1 fractionator.

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.

Table of Contents

The following tables set forth our segment information:

Three Months Ended September 30, 2012

	Natural Gas Services (e)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations (f)	Total
	(Millions)					
Total operating revenue	$ 278.5	$ 15.8	$ 36.7	$ —	$ (0.1)	$ 330.9
Total purchases	(232.9)	—	(35.2)	—	0.1	(268.0)
Gross margin (a)	$ 45.6	$ 15.8	$ 1.5	$ —	$ —	$ 62.9
Operating and maintenance expense	(26.9)	(5.1)	(3.7)	—	—	(35.7)
Depreciation and amortization expense	(12.5)	(1.6)	(0.6)	(0.1)	—	(14.8)
General and administrative expense	—	—	—	(11.1)	—	(11.1)
Other income	—	0.1	—	—	—	0.1
Earnings from unconsolidated affiliates	3.9	5.0	—	—	—	8.9
Interest expense, net	—	—	—	(8.1)	—	(8.1)
Income tax expense (b)	—	—	—	(0.3)	—	(0.3)
Net income (loss)	10.1	14.2	(2.8)	(19.6)	—	1.9
Net income attributable to noncontrolling interests	(0.6)	—	—	—	—	(0.6)
Net income (loss) attributable to partners	$ 9.5	$ 14.2	$ (2.8)	$(19.6)	$ —	$ 1.3
Non-cash derivative mark-to-market (c)	$ (20.8)	$ —	$ (2.1)	$ 0.4	$ —	$ (22.5)

Three Months Ended September 30, 2011

	Natural Gas Services (e)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations	Total
	(Millions)					
Total operating revenue	$ 478.8	$ 14.7	$ 100.1	$ —	$ —	$ 593.6
Total purchases	(354.9)	—	(94.1)	—	—	(449.0)
Gross margin (a)	$ 123.9	$ 14.7	$ 6.0	$ —	$ —	$ 144.6
Operating and maintenance expense	(28.0)	(5.5)	(3.2)	—	—	(36.7)
Depreciation and amortization expense	(22.8)	(2.4)	(0.7)	—	—	(25.9)
General and administrative expense	—	—	—	(12.0)	—	(12.0)
Other income	—	0.2	—	—	—	0.2
Earnings from unconsolidated affiliates	6.9	—	—	—	—	6.9
Interest expense, net	—	—	—	(8.6)	—	(8.6)
Income tax expense (b)	—	—	—	(0.4)	—	(0.4)
Net income (loss)	80.0	7.0	2.1	(21.0)	—	68.1
Net loss attributable to noncontrolling interests	0.4	—	—	—	—	0.4
Net income (loss) attributable to partners	$ 80.4	$ 7.0	$ 2.1	$(21.0)	$ —	$ 68.5
Non-cash derivative mark-to-market (c)	$ 61.0	$ —	$ 0.1	$ (0.7)	$ —	$ 60.4

Table of Contents

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

Nine Months Ended September 30, 2012

	Natural Gas Services (e)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations (f)	Total
	(Millions)					
Total operating revenue	$ 910.4	$ 46.2	$ 313.8	$ —	$ (0.2)	$1,270.2
Total purchases	(683.6)	—	(290.0)	—	0.2	(973.4)
Gross margin (a)	$ 226.8	$ 46.2	$ 23.8	$ —	$ —	$ 296.8
Operating and maintenance expense	(67.8)	(12.8)	(11.1)	—	—	(91.7)
Depreciation and amortization expense	(43.0)	(4.6)	(1.9)	(0.1)	—	(49.6)
General and administrative expense	—	—	—	(34.0)	—	(34.0)
Other income	—	0.4	—	—	—	0.4
Earnings from unconsolidated affiliates	11.6	5.0	—	—	—	16.6
Interest expense, net	—	—	—	(31.8)	—	(31.8)
Income tax expense (b)	—	—	—	(1.0)	—	(1.0)
Net income (loss)	127.6	34.2	10.8	(66.9)	—	105.7
Net income attributable to noncontrolling interests	(2.0)	—	—	—	—	(2.0)
Net income (loss) attributable to partners	$ 125.6	$ 34.2	$ 10.8	$(66.9)	$ —	$ 103.7
Non-cash derivative mark-to-market (c)	$ 5.4	$ —	$ 13.9	$ (0.4)	$ —	$ 18.9
Capital expenditures	$ 141.5	$ 8.5	$ 2.5	$ —	$ —	$ 152.5
Acquisition expenditures	$ 375.4	$ 29.8	$ —	$ —	$ —	$ 405.2
Investments in unconsolidated affiliates	$ 52.7	$ 33.6	$ —	$ —	$ —	$ 86.3

Nine Months Ended September 30, 2011

	Natural Gas Services (e)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations (f)	Total
	(Millions)					
Total operating revenue	$ 1,310.9	$ 42.3	$ 452.1	$ —	$ (2.2)	$ 1,803.1
Total purchases	(1,043.7)	(4.7)	(418.1)	—	2.2	(1,464.3)
Gross margin (a)	$ 267.2	$ 37.6	$ 34.0	$ —	$ —	$ 338.8
Operating and maintenance expense	(69.0)	(11.3)	(11.0)	—	—	(91.3)
Depreciation and amortization expense	(66.7)	(6.1)	(2.1)	—	—	(74.9)
General and administrative expense	—	—	—	(35.2)	—	(35.2)
Other income	—	0.4	—	—	—	0.4
Earnings from unconsolidated affiliates	17.1	—	—	—	—	17.1
Interest expense, net	—	—	—	(25.0)	—	(25.0)
Income tax expense (b)	—	—	—	(0.9)	—	(0.9)
Net income (loss)	148.6	20.6	20.9	(61.1)	—	129.0
Net income attributable to noncontrolling interests	(12.8)	—	—	—	—	(12.8)
Net income (loss) attributable to partners	$ 135.8	$ 20.6	$ 20.9	$(61.1)	$ —	$ 116.2
Non-cash derivative mark-to-market (c)	$ 49.7	$ —	$ (0.7)	$ (1.7)	$ —	$ 47.3
Capital expenditures	$ 88.8	$ 6.9	$ 2.8	$ —	$ —	$ 98.5
Acquisition expenditures	$ 145.3	$ 29.6	$ —	$ —	$ —	$ 174.9
Investments in unconsolidated affiliates	$ 6.8	$ —	$ —	$ —	$ —	$ 6.8

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

	September 30, 2012	December 31, 2011
	(Millions)	
Segment long-term assets:		
Natural Gas Services (e)	$ 1,768.1	$ 1,555.4
NGL Logistics	331.0	250.1
Wholesale Propane Logistics	104.5	104.2
Other (d)	43.2	14.0
Total long-term assets	2,246.8	1,923.7
Current assets	270.6	353.7
Total assets	$ 2,517.4	$ 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 nine months ended September 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 nine months ended September 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 nine months ended September 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

	Nine Months Ended September 30, 2012	2011
	(Millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$ 7.0	$ 7.4
Cash paid for income taxes, net of income tax refunds	$ 0.8	$ 29.9
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable	$ 8.3	$ 11.6
Other non-cash additions of property, plant and equipment	$ 5.8	$ 1.6
Non-cash change in parent advances	$ —	$ 4.4
Non-cash distributions to DCP Midstream, LLC	$ —	$ 2.6
Non-cash contributions from DCP Midstream, LLC	$ 3.3	$ —
Non-cash excess purchase price over acquired assets	$ 60.0	$ —

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.

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

	Condensed Consolidating Balance Sheet September 30, 2012				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 6.5	$ 1.9	$ —	$ 8.4
Accounts receivable	—	0.1	140.3	—	140.4
Inventories	—	—	71.6	—	71.6
Other	—	—	50.2	—	50.2
Total current assets	—	6.6	264.0	—	270.6
Property, plant and equipment, net	—	—	1,673.8	—	1,673.8
Goodwill and intangible assets, net	—	—	292.8	—	292.8
Advances receivable — consolidated subsidiaries	828.2	859.1	—	(1,687.3)	—
Investments in consolidated subsidiaries	279.5	465.6	—	(745.1)	—
Investments in unconsolidated affiliates	—	—	229.0	—	229.0
Other long-term assets	—	7.7	43.5	—	51.2
Total assets	$1,107.7	$1,339.0	$ 2,503.1	$ (2,432.4)	$ 2,517.4
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 18.2	$ 277.5	$ —	$ 295.7
Advances payable — consolidated subsidiaries	—	—	1,687.3	(1,687.3)	—
Long-term debt	—	1,038.3	—	—	1,038.3
Other long-term liabilities	—	3.0	38.9	—	41.9
Total liabilities	—	1,059.5	2,003.7	(1,687.3)	1,375.9
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	1,107.7	289.6	471.0	(745.1)	1,123.2
Accumulated other comprehensive loss	—	(10.1)	(5.4)	—	(15.5)
Total partners' equity	1,107.7	279.5	465.6	(745.1)	1,107.7
Noncontrolling interests	—	—	33.8	—	33.8
Total equity	1,107.7	279.5	499.4	(745.1)	1,141.5
Total liabilities and equity	$1,107.7	$1,339.0	$ 2,503.1	$ (2,432.4)	$ 2,517.4

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

	Condensed Consolidating Balance Sheet December 31, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
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.

Table of Contents

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

	Condensed Consolidating Statement of Operations Three Months Ended September 30, 2012				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 305.8	$ —	$ 305.8
Transportation, processing and other	—	—	45.0	—	45.0
Losses from commodity derivative activity, net	—	—	(19.9)	—	(19.9)
Total operating revenues	—	—	330.9	—	330.9
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	268.0	—	268.0
Operating and maintenance expense	—	—	35.7	—	35.7
Depreciation and amortization expense	—	—	14.8	—	14.8
General and administrative expense	—	—	11.1	—	11.1
Other income	—	—	(0.1)	—	(0.1)
Total operating costs and expenses	—	—	329.5	—	329.5
Operating income	—	—	1.4	—	1.4
Interest expense, net	—	(8.6)	0.5	—	(8.1)
Income from consolidated subsidiaries	1.3	9.9	—	(11.2)	—
Earnings from unconsolidated affiliates	—	—	8.9	—	8.9
Income before income taxes	1.3	1.3	10.8	(11.2)	2.2
Income tax expense	—	—	(0.3)	—	(0.3)
Net income	1.3	1.3	10.5	(11.2)	1.9
Net income attributable to noncontrolling interests	—	—	(0.6)	—	(0.6)
Net income attributable to partners	$ 1.3	$ 1.3	$ 9.9	$ (11.2)	$ 1.3

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

	Condensed Consolidating Statement of Comprehensive Income Three Months Ended September 30, 2012				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 1.3	$ 1.3	$ 10.5	$ (11.2)	$ 1.9
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	0.6	—	—	0.6
Net unrealized (losses) gains on cash flow hedges	—	(0.4)	1.1	—	0.7
Other comprehensive income from consolidated subsidiaries	1.3	1.1	—	(2.4)	—
Total other comprehensive income	1.3	1.3	1.1	(2.4)	1.3
Total comprehensive income	2.6	2.6	11.6	(13.6)	3.2
Total comprehensive income attributable to noncontrolling interests	—	—	(0.6)	—	(0.6)
Total comprehensive income attributable to partners	$ 2.6	$ 2.6	$ 11.0	$ (13.6)	$ 2.6

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

	Condensed Consolidating Statement of Operations Three Months Ended September 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 496.1	$ —	$ 496.1
Transportation, processing and other	—	—	42.8	—	42.8
Gains from commodity derivative activity, net	—	—	54.7	—	54.7
Total operating revenues	—	—	593.6	—	593.6
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	449.0	—	449.0
Operating and maintenance expense	—	—	36.7	—	36.7
Depreciation and amortization expense	—	—	25.9	—	25.9
General and administrative expense	—	—	12.0	—	12.0
Other income	—	—	(0.2)	—	(0.2)
Total operating costs and expenses	—	—	523.4	—	523.4
Operating income	—	—	70.2	—	70.2
Interest expense, net	—	(8.3)	(0.3)	—	(8.6)
Income from consolidated subsidiaries	68.5	76.8	—	(145.3)	—
Earnings from unconsolidated affiliates	—	—	6.9	—	6.9
Income before income taxes	68.5	68.5	76.8	(145.3)	68.5
Income tax expense	—	—	(0.4)	—	(0.4)
Net income	68.5	68.5	76.4	(145.3)	68.1
Net loss attributable to noncontrolling interests	—	—	0.4	—	0.4
Net income attributable to partners	$ 68.5	$ 68.5	$ 76.8	$ (145.3)	$ 68.5

(a) The financial information for the three months ended September 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 Statement of Comprehensive Income Three Months Ended September 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 68.5	$ 68.5	$ 76.4	$ (145.3)	$ 68.1
Other comprehensive loss:					
Reclassification of cash flow hedge losses into earnings	—	5.1	0.1	—	5.2
Net unrealized losses on cash flow hedges	—	(5.3)	(0.2)	—	(5.5)
Net unrealized losses on cash flow hedges - predecessor	—	—	(0.3)	—	(0.3)
Other comprehensive loss from consolidated subsidiaries	(0.6)	(0.4)	—	1.0	—
Total other comprehensive loss	(0.6)	(0.6)	(0.4)	1.0	(0.6)
Total comprehensive income	67.9	67.9	76.0	(144.3)	67.5
Total comprehensive loss attributable to noncontrolling interests	—	—	0.4	—	0.4
Total comprehensive income attributable to partners	$ 67.9	$ 67.9	$ 76.4	$ (144.3)	$ 67.9

(a) The financial information for the three months ended September 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 Statement of Operations Nine Months Ended September 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 1,089.4	$ —	$ 1,089.4
Transportation, processing and other	—	—	130.7	—	130.7
Gains from commodity derivative activity, net	—	—	50.1	—	50.1
Total operating revenues	—	—	1,270.2	—	1,270.2
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	973.4	—	973.4
Operating and maintenance expense	—	—	91.7	—	91.7
Depreciation and amortization expense	—	—	49.6	—	49.6
General and administrative expense	—	—	34.0	—	34.0
Other income	—	—	(0.4)	—	(0.4)
Total operating costs and expenses	—	—	1,148.3	—	1,148.3
Operating income	—	—	121.9	—	121.9
Interest expense, net	—	(31.5)	(0.3)	—	(31.8)
Income from consolidated subsidiaries	103.7	135.2	—	(238.9)	—
Earnings from unconsolidated affiliates	—	—	16.6	—	16.6
Income before income taxes	103.7	103.7	138.2	(238.9)	106.7
Income tax expense	—	—	(1.0)	—	(1.0)
Net income	103.7	103.7	137.2	(238.9)	105.7
Net income attributable to noncontrolling interests	—	—	(2.0)	—	(2.0)
Net income attributable to partners	$ 103.7	$ 103.7	$ 135.2	$ (238.9)	$ 103.7

(a) The financial information for the nine months ended September 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.

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

	Condensed Consolidating Statement of Comprehensive Income Nine Months Ended September 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 103.7	$ 103.7	$ 137.2	$ (238.9)	$ 105.7
Other comprehensive income (loss):					
Reclassification of cash flow hedge losses into earnings	—	9.9	—	—	9.9
Net unrealized (losses) gains on cash flow hedges	—	(0.6)	0.6	—	—
Net unrealized losses on cash flow hedges - predecessor	—	—	(0.6)	—	(0.6)
Other comprehensive income (loss) from consolidated subsidiaries	9.3	—	—	(9.3)	—
Total other comprehensive income (loss)	9.3	9.3	—	(9.3)	9.3
Total comprehensive income	113.0	113.0	137.2	(248.2)	115.0
Total comprehensive income attributable to noncontrolling interests	—	—	(2.0)	—	(2.0)
Total comprehensive income attributable to partners	$ 113.0	$ 113.0	$ 135.2	$ (248.2)	$ 113.0

(a) The financial information for the nine months ended September 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.

Table of Contents

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

	Condensed Consolidating Statement of Operations Nine Months Ended September 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 1,652.7	$ —	$ 1,652.7
Transportation, processing and other	—	—	122.2	—	122.2
Gains from commodity derivative activity, net	—	—	28.2	—	28.2
Total operating revenues	—	—	1,803.1	—	1,803.1
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	1,464.3	—	1,464.3
Operating and maintenance expense	—	—	91.3	—	91.3
Depreciation and amortization expense	—	—	74.9	—	74.9
General and administrative expense	—	—	35.2	—	35.2
Other income	—	—	(0.4)	—	(0.4)
Total operating costs and expenses	—	—	1,665.3	—	1,665.3
Operating income	—	—	137.8	—	137.8
Interest expense, net	—	(24.7)	(0.3)	—	(25.0)
Income from consolidated subsidiaries	116.2	140.9	—	(257.1)	—
Earnings from unconsolidated affiliates	—	—	17.1	—	17.1
Income before income taxes	116.2	116.2	154.6	(257.1)	129.9
Income tax expense	—	—	(0.9)	—	(0.9)
Net income	116.2	116.2	153.7	(257.1)	129.0
Net income attributable to noncontrolling interests	—	—	(12.8)	—	(12.8)
Net income attributable to partners	$ 116.2	$ 116.2	$ 140.9	$ (257.1)	$ 116.2

(a) The financial information for the nine months ended September 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 Statement of Comprehensive Income Nine Months Ended September 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 116.2	$ 116.2	$ 153.7	$ (257.1)	$ 129.0
Other comprehensive income (loss):					
Reclassification of cash flow hedge losses into earnings	—	15.4	0.2	—	15.6
Net unrealized losses on cash flow hedges	—	(9.5)	(0.3)	—	(9.8)
Net unrealized losses on cash flow hedges - predecessor	—	—	(0.7)	—	(0.7)
Other comprehensive income (loss) from consolidated subsidiaries	5.1	(0.8)	—	(4.3)	—
Total other comprehensive income (loss)	5.1	5.1	(0.8)	(4.3)	5.1
Total comprehensive income	121.3	121.3	152.9	(261.4)	134.1
Total comprehensive income attributable to noncontrolling interests	—	—	(12.8)	—	(12.8)
Total comprehensive income attributable to partners	$ 121.3	$ 121.3	$ 140.1	$ (261.4)	$ 121.3

(a) The financial information for the nine months ended September 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 Statement of Cash Flows Nine Months Ended September 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ (316.5)	$ (285.1)	$ 757.9	$ 2.5	$ 158.8
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(152.5)	—	(152.5)
Acquisitions, net of cash acquired	—	—	(375.4)	—	(375.4)
Acquisitions of unconsolidated affiliates	—	—	(29.8)	—	(29.8)
Investments in unconsolidated affiliates	—	—	(86.3)	—	(86.3)
Return of investment in unconsolidated affiliates	—	—	1.0	—	1.0
Proceeds from sale of assets	—	—	0.2	—	0.2
Net cash used in investing activities	—	—	(642.8)	—	(642.8)
FINANCING ACTIVITIES:					
Proceeds from debt	—	1,353.4	—	—	1,353.4
Payments of debt	—	(1,062.0)	—	—	(1,062.0)
Payment of deferred financing costs	—	(3.5)	—	—	(3.5)
Excess purchase price over acquired assets	—	—	(110.2)	—	(110.2)
Proceeds from issuance of common units, net of offering costs	445.2	—	—	—	445.2
Net change in advances to predecessor from DCP Midstream, LLC	—	—	(11.5)	—	(11.5)
Distributions to unitholders and general partner	(128.7)	—	—	—	(128.7)
Distributions to noncontrolling interests	—	—	(4.8)	—	(4.8)
Contributions from DCP Midstream, LLC	—	—	6.9	—	6.9
Net change in short-term borrowings	—	0.1	—	(0.1)	—
Net cash provided by (used in) financing activities	316.5	288.0	(119.6)	(0.1)	484.8
Net change in cash and cash equivalents	—	2.9	(4.5)	2.4	0.8
Cash and cash equivalents, beginning of period	—	3.6	6.4	(2.4)	7.6
Cash and cash equivalents, end of period	$ —	$ 6.5	$ 1.9	$ —	$ 8.4

(a) The financial information for the nine months ended September 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.

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

	Condensed Consolidating Statement of Cash Flows Nine Months Ended September 30, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ (54.5)	$ (77.3)	$ 313.2	$ (0.4)	$ 181.0
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(98.5)	—	(98.5)
Acquisitions, net of cash acquired	—	—	(174.9)	—	(174.9)
Investments in unconsolidated affiliates	—	—	(6.8)	—	(6.8)
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	—	—	(278.4)	—	(278.4)
FINANCING ACTIVITIES:					
Proceeds from debt	—	832.0	—	—	832.0
Payments of debt	—	(754.0)	—	—	(754.0)
Payments of deferred financing cost	—	(0.1)	—	—	(0.1)
Excess purchase price over acquired assets		—	(35.7)	—	(35.7)
Proceeds from issuance of common units, net of offering cost	152.0	—	—	—	152.0
Net change in advances to predecessor from DCP Midstream, LLC	—	—	14.6	—	14.6
Distributions to unitholders and general partner	(97.5)	—	—	—	(97.5)
Distributions to noncontrolling interests	—	—	(26.8)	—	(26.8)
Contributions from DCP Midstream, LLC	—	—	9.1	—	9.1
Net cash provided by (used in) financing activities	54.5	77.9	(38.8)	—	93.6
Net change in cash and cash equivalents	—	0.6	(4.0)	(0.4)	(3.8)
Cash and cash equivalents, beginning of period	—	1.5	6.7	(1.5)	6.7
Cash and cash equivalents, end of period	$ —	$ 2.1	$ 2.7	$ (1.9)	$ 2.9

(a) The financial information during the nine months ended September 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 October 29, 2012, the board of directors of the General Partner declared a quarterly distribution of $0.68 per unit, payable on November 14, 2012 to unitholders of record on November 7, 2012.

On November 2, 2012, we acquired a 33.33% interest in DCP SC Texas GP, or the Eagle Ford system, from DCP Midstream, LLC and fixed price commodity derivatives for a three-year period for aggregate consideration of $438.3 million, less customary working capital and other purchase price adjustments of $7.1 million. $343.5 million of the consideration was financed with a 2-year Term Loan Agreement and $87.7 million was financed by the issuance at closing of an aggregate 1,912,663 of our common units to DCP Midstream, LLC. Upon approval by the board of directors of each of DCP Midstream, LLC and the General Partner to construct the Goliad gas plant, we expect to contribute an additional estimated $16.7 million plus 33.33% of the working capital and construction work in process for the Goliad gas plant, to the Eagle Ford system. The Eagle Ford system acquisition represents a transaction between entities under common control. The results of the Eagle Ford system will be included in our Natural Gas Services segment.

On November 2, 2012, we borrowed $343.5 million on a 2-year Term Loan Agreement (the “$343.5 million Term Loan”) to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford system. The $343.5 million Term Loan will mature on November 2, 2014. The proceeds of any subsequent indebtedness issued with a maturity date after July 2, 2014 must first be used to prepay the existing $140 million Term Loan and any excess proceeds from indebtedness with a maturity after November 2, 2012 must be used to prepay the $343.5 million Term Loan. Indebtedness under the $343.5 million 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 $343.5 million 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 $343.5 million Term Loan Agreement) consistent with our Credit Agreement.

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 softened in relation to crude prices. Natural gas liquids and natural gas prices are currently below levels seen in recent years due to increasing supplies and a near record warm weather. 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. We use direct NGL hedges to mitigate a significant portion of our NGL price exposure, however, weakening of the relationship of natural gas liquids to crude oil prices does somewhat impact the effectiveness of our hedging program to mitigate our exposure to price fluctuations where we use crude oil to hedge our NGL price exposure.

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 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 are creating capacity constraint concerns. The amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs.

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. Our co-investment program may take numerous forms such as third-party acquisitions, organic build opportunities within our footprint, and accretive acquisition/dropdown opportunities with DCP Midstream, LLC. Co-investment capital commitments since the beginning of 2011 are nearly $1.4 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.
- On November 2, 2012, we acquired a 33.33% interest in DCP SC Texas, GP, or the Eagle Ford system, from DCP Midstream, LLC and fixed price commodity derivatives for a three-year period for aggregate consideration of $438.3 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 $234.0 million in capital, net of commissions and offering costs, 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. 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 allows 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. During the nine months ended September 30, 2012, we issued 893,389 of our common units pursuant to our equity distribution agreement and received proceeds of $37.4 million, net of commissions and offering costs of $0.9 million. Additionally, we entered into two 2-year Term Loan agreements and borrowed $140.0 million and $343.5 million to fund the cash portions of our acquisitions of the Mont Belvieu fractionators and the Eagle Ford system, respectively. As of September 30, 2012, the unused capacity under the revolving credit facility was $699.0 million, of which approximately $685.3 million was available for general working capital purposes**,** providing liquidity to continue to execute on our growth plans.

We raised our distributions for the quarter, resulting in a 6.3% increase in our quarterly distribution rate over the rate declared in the third quarter of 2011. The distributions reflect our business results as well as our recent execution on growth opportunities.

General Trends and Outlook

In the remainder of 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 $1.4 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 October 29, 2012, the board of directors of the General Partner declared a quarterly distribution of $0.68 per unit, payable on November 14, 2012 to unitholders of record on November 7, 2012.

On November 2, 2012, we acquired a 33.33% interest in DCP SC Texas GP, or the Eagle Ford system, from DCP Midstream, LLC and fixed price commodity derivatives for a three-year period for aggregate consideration of $438.3 million, less customary working capital and other purchase price adjustments of $7.1 million. $343.5 million of the consideration was financed with a 2-year Term Loan Agreement and $87.7 million was financed by the issuance at closing of an aggregate 1,912,663 of our common units. Upon the approval by the board of directors of each of DCP Midstream, LLC and the General Partner to construct the Goliad gas plant, we expect to contribute an additional estimated $16.7 million plus 33.33% of the working capital and construction work in process for the Goliad gas plant, to the Eagle Ford system. The Eagle Ford system acquisition represents a transaction between entities under common control. The results of the Eagle Ford system will be included in our Natural Gas Services segment.

On November 2, 2012, we borrowed $343.5 million on a 2-year Term Loan Agreement (the "$343.5 million Term Loan") to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford system. The $343.5 million Term Loan will mature on November 2, 2014. The proceeds of any subsequent indebtedness issued with a maturity date after July 2, 2014 must first be used to prepay the existing $140 million Term Loan and any excess proceeds from indebtedness with a maturity after November 2, 2012 must be used to prepay the $343.5 million Term Loan. Indebtedness under the $343.5 million 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 $343.5 million 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 $343.5 million Term Loan Agreement) consistent with our Credit Agreement.

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.

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.

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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of net income attributable to partners to gross margin:				
Net income attributable to partners	$ 1.3	$ 68.5	$103.7	$116.2
Interest expense	8.1	8.6	31.8	25.0
Income tax expense	0.3	0.4	1.0	0.9
Operating and maintenance expense	35.7	36.7	91.7	91.3
Depreciation and amortization expense	14.8	25.9	49.6	74.9
General and administrative expense	11.1	12.0	34.0	35.2
Other income	(0.1)	(0.2)	(0.4)	(0.4)
Earnings from unconsolidated affiliates	(8.9)	(6.9)	(16.6)	(17.1)
Net income (loss) attributable to noncontrolling interests	0.6	(0.4)	2.0	12.8
Gross margin	$ 62.9	$ 144.6	$296.8	$338.8
Non-cash commodity derivative mark-to-market (a)	$ (22.9)	$ 61.1	$ 19.3	$ 49.0
Reconciliation of segment net income attributable to partners to segment gross margin:				
Natural Gas Services segment:				
Segment net income attributable to partners	$ 9.5	$ 80.4	$125.6	$135.8
Operating and maintenance expense	26.9	28.0	67.8	69.0
Depreciation and amortization expense	12.5	22.8	43.0	66.7
Earnings from unconsolidated affiliates	(3.9)	(6.9)	(11.6)	(17.1)
Net income (loss) attributable to noncontrolling interests	0.6	(0.4)	2.0	12.8
Segment gross margin	$ 45.6	$ 123.9	$226.8	$267.2
Non-cash commodity derivative mark-to-market (a)	$ (20.8)	$ 61.0	$ 5.4	$ 49.7
NGL Logistics segment:				
Segment net income attributable to partners	$ 14.2	$ 7.0	$ 34.2	$ 20.6
Operating and maintenance expense	5.1	5.5	12.8	11.3
Depreciation and amortization expense	1.6	2.4	4.6	6.1
Other income	(0.1)	(0.2)	(0.4)	(0.4)
Earnings from unconsolidated affiliates	(5.0)	—	(5.0)	—
Segment gross margin	$ 15.8	$ 14.7	$ 46.2	$ 37.6
Wholesale Propane Logistics segment:				
Segment net (loss) income attributable to partners	$ (2.8)	$ 2.1	$ 10.8	$ 20.9
Operating and maintenance expense	3.7	3.2	11.1	11.0
Depreciation and amortization expense	0.6	0.7	1.9	2.1
Segment gross margin	$ 1.5	$ 6.0	$ 23.8	$ 34.0
Non-cash commodity derivative mark-to-market (a)	$ (2.1)	$ 0.1	$ 13.9	$ (0.7)

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 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)	$ 9.5	$ 80.4	$ 125.6	$ 135.8
Non-cash commodity derivative mark-to-market	20.8	(61.0)	(5.4)	(49.7)
Depreciation and amortization expense	12.5	22.8	43.0	66.7
Noncontrolling interest on depreciation and income tax	(0.3)	(3.4)	(1.1)	(10.2)
Adjusted segment EBITDA	$ 42.5	$ 38.8	$ 162.1	$ 142.6
NGL Logistics segment:				
Segment net income attributable to partners	$ 14.2	$ 7.0	$ 34.2	$ 20.6
Depreciation and amortization expense	1.6	2.4	4.6	6.1
Adjusted segment EBITDA	$ 15.8	$ 9.4	$ 38.8	$ 26.7
Wholesale Propane Logistics segment:				
Segment net (loss) income attributable to partners (b)	$ (2.8)	$ 2.1	$ 10.8	$ 20.9
Non-cash commodity derivative mark-to-market	2.1	(0.1)	(13.9)	0.7
Depreciation and amortization expense	0.6	0.7	1.9	2.1
Adjusted segment EBITDA	$ (0.1)	$ 2.7	$ (1.2)	$ 23.7

(a) Includes no lower of cost or market adjustments for the three months ended September 30, 2012 and $1.5 million lower of cost or market adjustments during the three months ended September 30, 2011. We recognized $3.9 million and $2.0 million of lower of cost or market adjustments during the nine months ended September 30, 2012 and September 30, 2011, respectively.

(b) Includes $0.2 million and $0.4 million lower of cost or market adjustments during the three months ended September 30, 2012 and 2011, respectively. We recognized $15.4 million and $0.5 million of lower of cost or market adjustments during the nine months ended September 30, 2012 and September 30, 2011, respectively.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Management's Discussion and Analysis of Financial Condition and Results of Operations 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 nine months ended September 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".

We performed our impairment testing of goodwill during the third quarter and concluded that the entire amount of goodwill on the balance sheet is recoverable. We primarily used a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. Our annual goodwill impairment tests indicated that our reporting units' fair values were substantially in excess of their carrying values. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

[Table of Contents](#)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2012 and 2011. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2012 vs. 2011		Variance Nine 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	$ 278.5	$ 478.8	$ 910.4	$1,310.9	$ (200.3)	(42)%	$ (400.5)	(31)%
NGL Logistics	15.8	14.7	46.2	42.3	1.1	7%	3.9	9%
Wholesale Propane Logistics	36.7	100.1	313.8	452.1	(63.4)	(63)%	(138.3)	(31)%
Intra-segment Eliminations	(0.1)	—	(0.2)	(2.2)	(0.1)	— %	2.0	91%
Total operating revenues	$ 330.9	$ 593.6	$1,270.2	$1,803.1	(262.7)	(44)%	(532.9)	(30)%
Gross margin (f):								
Natural Gas Services	$ 45.6	$ 123.9	$ 226.8	$ 267.2	(78.3)	(63)%	(40.4)	(15)%
NGL Logistics	15.8	14.7	46.2	37.6	1.1	7%	8.6	23%
Wholesale Propane Logistics	1.5	6.0	23.8	34.0	(4.5)	(75)%	(10.2)	(30)%
Total gross margin	62.9	144.6	296.8	338.8	(81.7)	(57)%	(42.0)	(12)%
Operating and maintenance expense	(35.7)	(36.7)	(91.7)	(91.3)	(1.0)	(3)%	0.4	— %
Depreciation and amortization expense	(14.8)	(25.9)	(49.6)	(74.9)	(11.1)	(43)%	(25.3)	(34)%
General and administrative expense	(11.1)	(12.0)	(34.0)	(35.2)	(0.9)	(8)%	(1.2)	(3)%
Other income	0.1	0.2	0.4	0.4	(0.1)	(50)%	—	— %
Earnings from unconsolidated affiliates (g)	8.9	6.9	16.6	17.1	2.0	29%	(0.5)	(3)%
Interest expense	(8.1)	(8.6)	(31.8)	(25.0)	(0.5)	(6)%	6.8	27%
Income tax expense	(0.3)	(0.4)	(1.0)	(0.9)	(0.1)	(25)%	0.1	11%
Net loss (income) attributable to noncontrolling interests	(0.6)	0.4	(2.0)	(12.8)	1.0	* %	(10.8)	(84)%
Net income attributable to partners	$ 1.3	$ 68.5	$ 103.7	$ 116.2	$ (67.2)	(98)%	$ (12.5)	(11)%
Other data:								
Non-cash commodity derivative mark-to-market	$ (22.9)	$ 61.1	$ 19.3	$ 49.0	$ (84.0)	* %	$ (29.7)	(61)%
Natural gas throughput (MMcf/d) (g)	1,659	1,367	1,648	1,429	292	21%	219	15%
NGL gross production (Bbls/d) (g)	62,232	50,369	62,729	54,010	11,863	24%	8,719	16%
NGL pipelines throughput (Bbls/d) (g)	69,863	68,564	75,115	57,802	1,299	2%	17,313	30%
Propane sales volume (Bbls/d)	9,128	15,257	18,383	23,944	(6,129)	(40)%	(5,561)	(23)%

* 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 nine months ended September 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 and Mont Belvieu fractionators since the dates of acquisition of March 24, 2011 and July 2, 2012, respectively, 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 nine months ended September 30, 2011, the 49.9% interest in East Texas owned by DCP Midstream, LLC was unhedged. As such, our consolidated results depict 49.9% of East Texas, unhedged for the three and nine months ended September 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 and the Mont Belvieu fractionators. 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 September 30, 2012 vs. Three Months Ended September 30, 2011

Total Operating Revenues — Total operating revenues decreased $262.7 million in 2012 compared to 2011 primarily as a result of the following:

- $125.7 million decrease primarily attributable to lower NGL and natural gas prices;
- $74.6 million decrease related to commodity derivative activity including $84.1 million change in non-cash derivative mark-to-market loss, offset by $9.5 million increase in settled derivatives. Included in our derivative activity are an increase in unrealized losses of $3.3 million and a decrease in realized gains of $1.5 million from the predecessor’s Southeast Texas storage business;
- $61.9 million decrease attributable to reduced Wholesale Propane Logistics segment volumes as a result of a lack of demand due to the industry’s excess inventory resulting from near record warm weather and lower propane prices; and
- $0.5 million decrease due to lower gas storage revenue, partially offset by increased volumes as a result of our planned turnaround activity and an extended planned third party outage in 2011 and our acquisition of the Crossroads system in 2012.

Gross Margin — Gross margin decreased $81.7 million in 2012 compared to 2011, primarily as a result of the following:

- $78.3 million decrease for our Natural Gas Services segment, primarily related to commodity derivative activity and lower commodity prices, partially offset by increased volumes attributable to higher unit margin on physical sales related to our natural gas storage and pipeline assets, planned turnaround activity and extended planned third party outages in 2011, and our acquisition of the Crossroads system in 2012; and
- $4.5 million decrease for our Wholesale Propane Logistics segment, primarily due to reduced volumes as a result of a lack of demand due to the industry's excess inventory resulting from near record warm weather and lower per unit margins, partially offset by the sale of inventory written down in Q2 2012.

These decreases were partially offset by:

- $1.1 million increase for our NGL Logistics segment as a result of increased throughput on our pipelines, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2012 compared to 2011, primarily as a result of timing of expenditures, partially offset by our acquisition of the Crossroads system in 2012. 2011 results reflect planned turnaround activity and environmental remediation at East Texas, and the impact of timing of expenditures related to the transition and integration of our Marysville acquisition and pipeline integrity testing.

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 lives of our assets.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, 20% ownership of the Mont Belvieu 1 Fractionator, 12.5% ownership of the Mont Belvieu Enterprise Fractionator, and 50% ownership in CrossPoint, increased in 2012 compared to 2011 primarily as a result of our acquisition of the Mont Belvieu Fractionators in July 2012, partially offset by lower commodity prices and reduced throughput volumes on Discovery. 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 increased in 2012 compared to 2011 as a result of our acquisition of the remaining 49.9% of East Texas.

Nine Months Ended September 30, 2012 vs. Nine Months Ended September 30, 2011

Total Operating Revenues — Total operating revenues decreased $532.9 million in 2012 compared to 2011 primarily as a result of the following:

- $313.1 million decrease primarily attributable to lower NGL and natural gas prices;
- $155.1 million decrease attributable to reduced Wholesale Propane Logistics segment volumes as a result of a lack of demand due to the industry's excess inventory resulting from near record warm weather, and lower propane prices; and
- $86.6 million decrease primarily due to lower volumes, lower gas storage revenue and the East Texas recovery settlement in 2011, partially offset by our acquisition of the Crossroads system in 2012.

These decreases were partially offset by:

- $21.9 million increase related to commodity derivative activity including $29.9 million change in non-cash derivative mark-to-market losses offset by $51.8 million increase in settled derivatives. Included in our derivative activity are an increase in unrealized losses of $25.2 million and an increase in realized gains of $26.7 million from the predecessor's Southeast Texas storage business.

Gross Margin — Gross margin decreased $42.0 million in 2012 compared to 2011, primarily as a result of the following:

- $40.4 million decrease for our Natural Gas Services segment, primarily related to lower commodity prices, decreased volumes and differences in gas quality across certain assets, and the East Texas recovery settlement in 2011, partially offset by increased commodity derivative activity and our acquisition of the Crossroads system in 2012; and
- $10.2 million decrease for our Wholesale Propane Logistics segment primarily due to a non-cash lower of cost or market inventory adjustment of $15.4 million, a lack of demand due to the industry's excess inventory resulting from near record warm weather, and lower per unit margins, partially offset by commodity derivative activities and the sale of inventory written down in Q2 2012.

These decreases were partially offset by:

- $8.6 million increase for our NGL Logistics segment as a result of increased throughput on certain of our pipelines, the completion of the Wattenberg expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2012 compared to 2011 as result of the completion of the Wattenberg capital expansion project, and our acquisition of the Crossroads system in 2012 and the DJ Basin NGL fractionators. 2011 results reflect planned turnaround activity and environmental remediation at East Texas.

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 lives of our assets.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, 20% ownership of the Mont Belvieu 1 Fractionator, 12.5% ownership of the Mont Belvieu Enterprise Fractionator, and 50% ownership in CrossPoint, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes on Discovery, partially offset by our acquisition of the Mont Belvieu Fractionators in July 2012. 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.

Table of Contents

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 September 30,		Nine Months Ended September 30,		Variance Three Months 2012 vs. 2011		Variance Nine 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	$ 267.7	$ 396.0	$ 791.1	$1,196.6	$ (128.3)	(32)%	$ (405.5)	(34)%
Transportation, processing and other	29.3	28.2	84.6	84.7	1.1	4%	(0.1)	— %
(Losses) gains from commodity derivative activity	(18.5)	54.6	34.7	29.6	(73.1)	(134)%	5.1	17%
Total operating revenues	278.5	478.8	910.4	1,310.9	(200.3)	(42)%	(400.5)	(31)%
Purchases of natural gas and NGLs	232.9	354.9	683.6	1,043.7	(122.0)	(34)%	(360.1)	(35)%
Segment gross margin (c)	45.6	123.9	226.8	267.2	(78.3)	(63)%	(40.4)	(15)%
Operating and maintenance expense	(26.9)	(28.0)	(67.8)	(69.0)	(1.1)	(4)%	(1.2)	(2)%
Depreciation and amortization expense	(12.5)	(22.8)	(43.0)	(66.7)	(10.3)	(45)%	(23.7)	(36)%
Earnings from unconsolidated affiliates (d)	3.9	6.9	11.6	17.1	(3.0)	(43)%	(5.5)	(32)%
Segment net income	10.1	80.0	127.6	148.6	(69.9)	(87)%	(21.0)	(14)%
Segment net (income) loss attributable to noncontrolling interests	(0.6)	0.4	(2.0)	(12.8)	1.0	*%	(10.8)	(84)%
Segment net income attributable to partners	$ 9.5	$ 80.4	$ 125.6	$ 135.8	$ (70.9)	(88)%	$ (10.2)	(8)%
Other data:								
Non-cash commodity derivative mark-to-market	$ (20.8)	$ 61.0	$ 5.4	$ 49.7	$ (81.8)	*%	$ (44.3)	(89)%
Natural gas throughput (MMcf/d) (d)	1,659	1,367	1,648	1,429	292	21%	219	15%
NGL gross production (Bbls/d) (d)	62,232	50,369	62,729	54,010	11,863	24%	8,719	16%

* 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 nine months ended September 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 nine months ended September 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 nine months ended September 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 September 30, 2012 vs. Three Months Ended September 30, 2011

Total Operating Revenues — Total operating revenues decreased $200.3 million in 2012 compared to 2011, primarily as a result of the following:

- $87.7 million decrease attributable to lower commodity prices;
- $73.1 million decrease related to commodity derivative activity. This includes a change in unrealized commodity derivative activity in 2012 compared to 2011of $81.9 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 $8.8 million. Included in our derivative activity are an increase in unrealized losses of $3.3 million and a decrease in realized gains of $1.5 million from the predecessor's Southeast Texas storage business; and
- $53.2 million decrease attributable to decreased prices and volumes for physical sales related to our natural gas storage and pipeline assets.

These decreases were partially offset by:

- $12.6 million increase primarily attributable to increased volumes across certain assets and our acquisition of the Crossroads system in 2012. 2011 results reflect planned turnaround activity at East Texas and Southeast Texas, and an extended planned third party outage at our Wyoming asset; and
- $1.1 million increase in transportation, processing and other revenues as a result of our acquisition of the Crossroads system in 2012.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $122.0 million in 2012 compared to 2011 primarily as a result of lower commodity prices; partially offset by higher volumes and our acquisition of the Crossroads system in 2012.

Segment Gross Margin — Segment gross margin decreased $78.3 million in 2012 compared to 2011, primarily as a result of the following:

- $73.1 million decrease related to commodity derivative activities as discussed above; and
- $13.6 million decrease as a result of lower commodity prices.

These decreases were partially offset by:

- $8.4 million increase attributable to higher unit margin on physical sales related to our natural gas storage and pipeline assets, and our acquisition of the Crossroads system in 2012; partially offset by lower volumes and differences in gas quality across certain assets. 2011 results reflect planned turnaround activity at East Texas and Southeast Texas and an extended planned third party outage at our Wyoming asset.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2012 compared to 2011 primarily as a result of timing of expenditures, partially offset by our acquisition of the Crossroads system in 2012. 2011 results reflect planned turnaround activity and environmental remediation at East Texas.

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 lives of our assets.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery and 50% ownership in CrossPoint, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes on Discovery, partially offset by settlements of commercial disputes. 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 increased 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 and the Crossroads system in 2012, partially offset by decreased volumes across certain assets. 2011 results reflect planned turnaround activity at East Texas and Southeast Texas, and an extended planned third party outage at our Wyoming asset.

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 and the Crossroads system in 2012, partially offset by decreased volumes and differences in gas quality across certain assets. 2011 results reflect planned turnaround activity at East Texas and Southeast Texas, and an extended planned third party outage at our Wyoming asset.

Nine Months Ended September 30, 2012 vs. Nine Months Ended September 30, 2011

Total Operating Revenues — Total operating revenues decreased $400.5 million in 2012 compared to 2011, primarily as a result of the following:

- $179.4 million decrease attributable to lower commodity prices;
- $169.3 million decrease attributable to decreased prices and volumes for physical sales related to our natural gas storage and pipeline assets;
- $51.1 million decrease primarily attributable to decreased volumes across certain assets and differences in gas quality, partially offset by 2011 planned turnaround activity at East Texas and Southeast Texas; and
- $5.8 million decrease as a result of the East Texas recovery settlement in 2011.

These decreases were partially offset by:

- $5.1 million increase related to commodity derivative activity. This includes a change in unrealized commodity derivative activity in 2012 compared to 2011of $44.5 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 $49.6 million. Included in our derivative activity are an increase in unrealized losses of $25.2 million and an increase in realized gains of $26.7 million from the predecessor’s Southeast Texas storage business.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $360.1 million in 2012 compared to 2011 primarily as a result of lower commodity prices and decreased volumes across certain assets, partially offset by our acquisition of the Crossroads system in 2012.

Segment Gross Margin — Segment gross margin decreased $40.4 million in 2012 compared to 2011, primarily as a result of the following:

- $26.9 million decrease as a result of lower commodity prices;
- $12.8 million decrease primarily attributable to decreased volumes and differences in gas quality across certain assets. 2011 results reflect planned turnaround activity at East Texas and Southeast Texas; and
- $5.8 million decrease as a result of the East Texas recovery settlement in 2011.

These decreases were partially offset by:

- $5.1 million increase related to commodity derivative activities as discussed in the Operating Revenues section above.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2012 compared to 2011 primarily as a result of timing of expenditures, partially offset by our acquisition of the Crossroads system in 2012. 2011 results reflect planned turnaround activity and environmental remediation at East Texas.

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 lives of our assets.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery and 50% ownership in CrossPoint, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes on Discovery, 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 and the Crossroads system, in 2012 partially offset by decreased volumes across certain assets. 2011 results reflect planned turnaround activity at East Texas and Southeast Texas.

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 and the Crossroads system in 2012, partially offset by decreased volumes and differences in gas quality across certain assets. 2011 results reflect planned turnaround activity at East Texas and Southeast Texas.

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, our DJ Basin NGL fractionators and our minority ownership interests in the Mont Belvieu fractionators:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2012 vs. 2011		Variance Nine 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	$ —	$ —	$ —	$ 4.9	$ —	— %	$ (4.9)	(100)%
Transportation, processing and other	15.8	14.7	46.2	37.4	1.1	7%	8.8	24%
Total operating revenues	15.8	14.7	46.2	42.3	1.1	7%	3.9	9%
Purchases of NGLs	—	—	—	4.7	—	— %	(4.7)	(100)%
Segment gross margin (a)	15.8	14.7	46.2	37.6	1.1	7%	8.6	23%
Operating and maintenance expense	(5.1)	(5.5)	(12.8)	(11.3)	(0.4)	(7)%	1.5	13%
Depreciation and amortization expense	(1.6)	(2.4)	(4.6)	(6.1)	(0.8)	(33)%	(1.5)	(25)%
Other income	0.1	0.2	0.4	0.4	(0.1)	(50)%	—	— %
Earnings from unconsolidated affiliates (c)	5.0	—	5.0	—	5.0	100%	5.0	100%
Segment net income attributable to partners	$ 14.2	$ 7.0	$ 34.2	$ 20.6	$ 7.2	103%	$ 13.6	66%
Other data:								
NGL pipelines throughput (Bbls/d) (c)	69,863	68,564	75,115	57,802	1,299	2%	17,313	30%

(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 and Mont Belvieu fractionators since the dates of acquisition of March 24, 2011 and July 2, 2012, respectively.
(c) Includes our share, based on our ownership percentage, of the throughput volumes and earnings of the Mont Belvieu fractionators.

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

Total Operating Revenues — Total operating revenues increased in 2012 compared to 2011 as result of increased throughput on our pipelines, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Segment Gross Margin — Segment gross margin increased in 2012 compared to 2011 as result of increased throughput on our pipelines, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2012 compared to 2011. 2011 results were impacted by the timing of expenditures related to the transition and integration of our Marysville acquisition and pipeline integrity testing.

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 lives of our assets.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing 20% ownership of the Mont Belvieu 1 Fractionator and 12.5% ownership of the Mont Belvieu Enterprise Fractionator, increased in 2012 compared to 2011 as a result the acquisition of the Mont Belvieu Fractionators in July 2012.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2012 compared to 2011 as a result of volume growth on our pipelines, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Nine Months Ended September 30, 2012 vs. Nine Months Ended September 30, 2011

Total Operating Revenues — Total operating revenues increased in 2012 compared to 2011 as result of increased throughput on our pipelines, the completion of the Wattenberg capital expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Segment Gross Margin — Segment gross margin increased in 2012 compared to 2011 as result of increased throughput on our pipelines, the completion of the Wattenberg capital expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

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

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing 20% ownership of the Mont Belvieu 1 Fractionator and 12.5% ownership of the Mont Belvieu Enterprise Fractionator, increased in 2012 compared to 2011 as a result the acquisition of the Mont Belvieu Fractionators in July 2012.

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, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Table of Contents

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 September 30,		Nine Months Ended September 30,		Variance Three Months 2012 vs. 2011		Variance Nine Months 2012 vs. 2011	
	2012	2011	2012	2011	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of propane	$ 38.1	$ 100.1	$ 298.3	$ 453.4	$ (62.0)	(62)%	$ (155.1)	(34)%
Other	—	(0.1)	0.1	0.1	0.1	100%	—	— %
(Losses) gains from commodity derivative activity	(1.4)	0.1	15.4	(1.4)	(1.5)	*%	16.8	*%
Total operating revenues	36.7	100.1	313.8	452.1	(63.4)	(63)%	(138.3)	(31)%
Purchases of propane	35.2	94.1	290.0	418.1	(58.9)	(63)%	(128.1)	(31)%
Segment gross margin (a)	1.5	6.0	23.8	34.0	(4.5)	(75)%	(10.2)	(30)%
Operating and maintenance expense	(3.7)	(3.2)	(11.1)	(11.0)	0.5	16%%	0.1	1%
Depreciation and amortization expense	(0.6)	(0.7)	(1.9)	(2.1)	(0.1)	(14)%	(0.2)	(10)%
Segment net (loss) income attributable to partners	$ (2.8)	$ 2.1	$ 10.8	$ 20.9	$ (4.9)	*%	$ (10.1)	(48)%
Other data:								
Non-cash commodity derivative mark-to-market	$ (2.1)	$ 0.1	$ 13.9	$ (0.7)	$ (2.2)	*%	$ 14.6	*%
Propane sales volume (Bbls/d)	9,128	15,257	18,383	23,944	(6,129)	(40)%	(5,561)	(23)%

* 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 September 30, 2012 vs. Three Months Ended September 30, 2011

Total Operating Revenues — Total operating revenues decreased by $63.4 million in 2012 compared to 2011, primarily as a result of the following:

- $39.6 million decrease attributable to reduced sales volumes primarily as a result of a lack of demand due to the industry's excess inventory resulting from near record warm weather;
- $22.3 million decrease attributable to lower propane prices; and
- $1.5 million decrease related to a decrease in unrealized commodity derivative activity of $2.2 million, offset by an increase in realized cash settlements of $0.7 million.

Purchases of Propane — Purchases of propane decreased in 2012 compared to 2011 primarily due to reduced volumes as a result of inventory build resulting from near record warm weather, offset by a modest recovery of the lower of cost or market inventory adjustment recognized in Q2 2012, through the sale of inventory.

Segment Gross Margin — Segment gross margin decreased in 2012 compared to 2011 primarily due to reduced volumes as a result of a lack of demand due to the industry's excess inventory resulting from near record warm weather and lower per unit margins, offset by a modest recovery of the lower of cost or market inventory adjustment recognized in Q2 2012, through the sale of inventory.

Operating and Maintenance Expense — Operating and maintenance expense increased 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 as a result of a lack of demand due to the industry's excess inventory resulting from near record warm weather.

Nine Months Ended September 30, 2012 vs. Nine Months Ended September 30, 2011

Total Operating Revenues — Total operating revenues decreased $138.3 million in 2012 compared to 2011, primarily as a result of the following:

- $113.2 million decrease attributable to reduced sales volumes primarily as a result of a lack of demand due to the industry's excess inventory resulting from near record warm weather; and
- $41.9 million decrease attributable to lower propane prices.

These decreases were partially offset by:

- $16.8 million increase related to a change in unrealized commodity derivative activity of $14.6 million and a change in realized commodity derivative activity of $2.2 million.

Purchases of Propane — Purchases of propane decreased in 2012 compared to 2011 primarily due to reduced volumes as a result of inventory build resulting from near record warm weather and lower propane prices, partially offset by a non-cash lower of cost or market inventory adjustment of $15.4 million in 2012, offset by a modest recovery through the sale of inventory.

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 $15.4 million, offset by a modest recovery through the sale of inventory, a lack of demand due to the industry's excess inventory resulting from near record warm weather, and lower per unit margins, partially offset by commodity derivative activities of $16.8 million discussed above.

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

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 as a result of a lack of demand due to the industry's excess inventory resulting from near record warm weather.

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 November 2, 2012, we had approximately $566.0 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.

In January 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.

In March 2012, we issued $350.0 million of 4.95% 10-year Senior Notes due April 1, 2022. We received proceeds of $345.8 million, net of underwriters' fees, related expenses and unamortized discount, 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.

In July 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 November 2012, we entered into a 2-year Term Loan Agreement and borrowed $343.5 million to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford system.

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 months ended September 30, 2012, we issued 554,589 of our common units pursuant to the equity distribution agreement, and received proceeds of $23.3 million, net of commissions and offering costs of $0.6 million. During the nine months ended September 30, 2012, we issued 893,389 of our common units pursuant to the equity distribution agreement, and received proceeds of $37.4 million, net of commissions and offering costs of $0.9 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 $234.0 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 allows us to issue additional partnership equity and debt securities. As of November 2, 2012, we have issued no securities under this registration statement.

In July 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, for a total of $177.4 million, and received proceeds of $173.8 million net of offering costs.

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

In November 2012, we issued 1,912,663 common units to DCP Midstream, LLC as partial consideration for the acquisition of a 33.33% interest in the Eagle Ford system.

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 November 2, 2012, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $25.0 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 November 2, 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 a working capital deficit of $25.1 million as of September 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 $3.9 million and net derivative working capital liabilities of $18.7 million as of September 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 September 30, 2012, we had $8.4 million in cash and cash equivalents. Of this balance, $1.9 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 partnership purposes.

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

	Nine Months Ended September 30,	
	2012	2011
	(Millions)	
Net cash provided by operating activities	$ 158.8	$ 181.0
Net cash used in investing activities	$(642.8)	$(278.4)
Net cash provided by financing activities	$ 484.8	$ 93.6

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 and $1.2 million in other net cash hedge settlements for the nine months ended September 30, 2012. We received $2.9 million for our net hedge cash settlements related to the Southeast Texas storage business, offset by $23.9 million in other net cash hedge settlements paid, for the nine months ended September 30, 2011.

We received cash distributions from unconsolidated affiliates of $15.9 million and $19.8 million during the nine months ended September 30, 2012 and 2011, respectively. Earnings exceeded distributions by $0.7 million for the nine months ended September 30, 2012, and distributions exceeded earnings by $2.7 million for the nine months ended September 30, 2011.

Net Cash Used in Investing Activities — Net cash used in investing activities during the nine months ended September 30, 2012 was comprised of: (1) acquisition expenditures of $405.2 million, of which $192.5 million is related to our acquisition of the remaining 66.67% interest in Southeast Texas, $119.9 million related to our acquisition of the remaining 49.9% interest in East Texas, $63.0 million related to our acquisition of Crossroads, and $29.8 million related to our acquisition of the Mont Belvieu fractionators; (2) capital expenditures of $152.5 million (our portion of which was $140.6 million and the reimbursable projects portion was $11.9 million); and (3) investments in unconsolidated affiliates of $86.3 million; partially offset by (4) return of investment from unconsolidated affiliate of $1.0 million; and (5) proceeds from sales of assets of $0.2 million.

Net cash used in investing activities during the nine months ended September 30, 2011 was comprised of: (1) acquisition expenditures of $114.3 million, related to our acquisition of Southeast Texas; (2) acquisition expenditures of $29.7 million related to our acquisition of our DJ Basin NGL fractionators; (3) acquisition expenditures of $23.4 million, related to construction of our Eagle Plant; (4) payment of $7.5 million to the seller of Michigan Pipeline & Processing, LLC in relation to our contingent payment agreement; (5) capital expenditures of $98.5 million (our portion of which was $88.9 million and the noncontrolling interest holders' portion was $9.6 million); and (6) investments in unconsolidated affiliates of $6.8 million; partially offset by (7) a return of investment from unconsolidated affiliates of $1.6 million; and (8) proceeds from sales of assets of $0.2 million.

Net Cash Provided by Financing Activities — Net cash provided by financing activities during the nine months ended September 30, 2012 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $445.2 million; (2) proceeds from debt of $1,353.4 million, offset by repayments of $1,062.0 million, for net borrowing of debt of $291.4 million; and (3) contributions from DCP Midstream, LLC of $6.9 million; partially offset by (4) distributions to our unitholders and general partner of $128.7 million; (5) excess purchase price over acquired net assets of $110.2 million; (6) change in advances to predecessor from DCP Midstream, LLC of $11.5 million; (7) distributions to noncontrolling interests of $4.8 million; and (8) payment of deferred financing costs of $3.5 million.

Net cash provided by financing activities during the nine months ended September 30, 2011 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $152.0 million; (2) proceeds from debt of $832.0 million, offset by repayments of $754.0 million, for net borrowing of debt of $78.0 million; (3) net change in advances to predecessor from DCP Midstream, LLC of $14.6 million; and (4) contributions from noncontrolling interests of $9.1 million; partially offset by (5) distributions to our unitholders and general partner of $97.5 million; (6) excess purchase price over the acquired net assets of Southeast Texas of $35.7 million; (7) distributions to noncontrolling interests of $26.8 million; and (8) payment of deferred financing costs of $0.1 million.

During the nine months ended September 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 nine months ended September 30, 2012 was $395.2 million.

We had unused revolver capacity, which is available commitments under the Credit Agreement, of $699.0 million as of September 30, 2012.

During the nine months ended September 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
- $37.2 million net borrowings.

During the nine months ended September, 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
- $80.2 million net borrowings; partially offset by
- $152.2 million repayment financed by the issue of 3,941,667 common units in the nine months ended September 30, 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 $1.4 billion, for the year ending December 31, 2012. Expansion capital expenditures include construction of the Texas Express Pipeline and Discovery's Keathley Canyon, and acquisition of the Mont Belvieu fractionators, 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, Southeast Texas, the Crossroads system in East Texas and our 33.33% interest in the Eagle Ford system. 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:

	Nine months ended September 30, 2012			Nine months ended September 30, 2011		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	$ 11.2	$ 129.4	$ 140.6	$ 8.4	$ 80.5	$ 88.9
Noncontrolling interest portion and reimbursable projects (a)	4.6	7.3	11.9	3.7	5.9	9.6
Total	$ 15.8	$ 136.7	$ 152.5	$ 12.1	$ 86.4	$ 98.5

(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 $86.3 million and $6.8 million during the nine months ended September 30, 2012 and 2011, respectively, 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 $128.7 million during the nine months ended September 30, 2012, as compared to $97.5 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 September 30, 2012, the outstanding balance on the revolving credit facility was $300.0 million resulting in unused revolver capacity of $699.0 million, of which approximately $685.3 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 September 30, 2012 and December 31, 2011, we had $1.0 million outstanding letters of credit issued under the Credit Agreement.

As of September 30, 2012, the weighted-average interest rate on our revolving credit facility was 1.48% per annum, excluding the impact of interest rate swaps.

Description of the Term Loan Agreements — On November 2, 2012, we borrowed $343.5 million on a 2-year Term Loan Agreement (the "$343.5 million Term Loan") to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford system. The $343.5 million Term Loan will mature on November 2, 2014. The proceeds of any subsequent indebtedness issued with a maturity date after July 2, 2014 must first be used to prepay the existing $140 million Term Loan and any excess proceeds from indebtedness with a maturity after November 2, 2012 must be used to prepay the $343.5 million Term Loan. Indebtedness under the $343.5 million 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 $343.5 million 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 $343.5 million Term Loan Agreement) consistent with our Credit Agreement.

On July 2, 2012, we entered into a 2-year Term Loan Agreement and borrowed $140.0 million (the "$140 million Term Loan") to fund the cash portion of the acquisition of the Mont Belvieu fractionators. The $140 million Term Loan will mature on July 2, 2014. Effective November 1, 2012, the proceeds of any subsequent indebtedness issued with a maturity date after July 2, 2014 must first be used to prepay the $140 million Term Loan. Indebtedness under the $140 million 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 $140 million 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 $140 million Term Loan Agreement) consistent with our Credit Agreement. On January 2, 2013 and July 2, 2013, one-time payments of 0.125% and 0.20%, respectively, on the outstanding principal amount of the $140 million Term Loan are required.

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.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of September 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)	$1,256.7	$ 33.1	$ 196.4	$ 589.3	$ 437.9
Operating lease obligations (b)	28.1	11.8	11.0	4.3	1.0
Purchase obligations (c)	251.0	143.0	59.0	49.0	—
Other long-term liabilities (d)	17.7	—	0.7	0.2	16.8
Total	$1,553.5	$ 187.9	$ 267.1	$ 642.8	$ 455.7

(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 September 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 $16.6 million of asset retirement obligations and $1.1 million of environmental reserves recognized in the September 30, 2012 condensed consolidated balance sheet.

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

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. $300.0 million of swap agreements settled in Q2 2012.

At September 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 condensed 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 September 30, 2012, the effective weighted-average interest rate on our outstanding debt was 3.55%, 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 $150.0 million as of September 30, 2012, a 0.5% movement in the base rate or LIBOR rate result in an approximately $0.8 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 risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices, however there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. During 2012, the relationship of NGLs to crude oil has been lower than historical relationships, however a significant amount of our NGL hedges in 2012 and 2013 are direct product hedges. 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.

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.

Table of Contents

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 November 2, 2012, including the hedges acquired in connection with the Eagle Ford system acquisition:

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Reference Price	Price Range
October 2012 —December 2012	Natural Gas	(1,181) MMBtu/d	Monthly Average for Carthage Gas Daily Daily (e)	$4.34/MMBtu
October 2012 — December 2014	Natural Gas	(500) MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a)	$5.06/MMBtu
October 2012 — December 2014	Natural Gas	(1,000) MMBtu/d	Texas Gas Transmission Price (b)	$4.87/MMBtu
November 2012 — December 2012	Natural Gas	(7,416) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (f)	$4.50/MMBtu
January 2013 — December 2013	Natural Gas	(9,185) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (f)	$4.50/MMBtu
January 2014 — December 2014	Natural Gas	(8,401) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (f)	$4.50/MMBtu
January 2015 — December 2015	Natural Gas	(9,244) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (f)	$4.50/MMBtu
November 2012 — December 2012	Natural Gas	(1,048) MMBtu/d	IFERC Monthly Index Price for Henry Hub (g)	$4.50/MMBtu
January 2013 — December 2015	Natural Gas	(2,467) MMBtu/d	IFERC Monthly Index Price for Henry Hub (g)	$4.50/MMBtu
November 2012 — December 2012	NGL’s	(3,450) Bbls/d	Mt.Belvieu Non-TET (d)	$0.64-$1.89/Gal
January 2013 — December 2013	NGL’s	(4,652) Bbls/d	Mt.Belvieu Non-TET (d)	$0.64-$1.89/Gal
January 2014 — December 2014	NGL’s	(4,746) Bbls/d	Mt.Belvieu Non-TET (d)	$0.64-$1.89/Gal
January 2015 — December 2015	NGL’s	(5,032) Bbls/d	Mt.Belvieu Non-TET (d)	$0.64-$1.89/Gal
October 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
October 2012 — December 2012	NGL’s	(702) Bbls/d	Mt.Belvieu Non-TET (d)	$2.20/Gal
November 2012 — December 2015	Crude Oil	(101) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$95.00/Bbl
October 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
October 2012 — December 2014	Natural Gas	500 MMBtu/d	Texas Gas Transmission Price (b)	$4.93/MMBtu
October 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.
(f) The Inside FERC monthly published index price for Houston Ship Channel.
(g) The inside FERC monthly published index price for Henry Hub.

Commodity Collar Arrangements

Period	Commodity	Notional Volume	Reference Price	Collar Price Range
October 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.

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	$	0.9
Crude oil prices	$ 5.00	Barrel	$	11.7
NGL prices	$ 0.10	Gallon	$	7.1

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.

Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices, however there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. During 2012, the relationship of NGLs to crude oil has been lower than historical relationships, however a significant amount of our NGL hedges in 2012 and 2013 are direct product hedges. 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.

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 September 30, 2012:

Inventory

Period	Commodity	Notional Volume - Long Positions	Fair Value (millions)	Weighted Average Price
September 30, 2012	Natural Gas	5,439,708 MMBtu's	$ 13.9	$2.55/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Fair Value (millions)	Price Range
October 2012-December 2012	Natural Gas	(32,495,000) MMBtu's	$ (9.1)	$2.59-$3.41/MMBtu
January 2013-October 2013	Natural Gas	(19,000,000) MMBtu's	$ (6.5)	$3.19-$3.61/MMBtu
October 2012-December 2012	Natural Gas	33,465,000 MMBtu's	$ 6.0	$2.34-$4.50/MMBtu
January 2013-November 2013	Natural Gas	10,500,000 MMBtu's	$ 3.3	$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 September 30, 2012, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of September 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 September 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 and our subsequent quarterly reports on Form 10-Q. 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 and our subsequent quarterly reports on Form 10-Q. 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.

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 August 16, 2012, the U.S. Environmental Protection Agency ("EPA") published final regulations under the Clean Air Act that 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. EPA has recently released a draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where EPA is the permitting authority. 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 26, 2011, the EPA published a plan to propose regulations in 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.

The amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport and store, may be reduced if the pipelines and storage fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs.

The natural gas we gather, compress, treat, process, transport and store is delivered into pipelines for further delivery to end-users. If these pipelines are capacity constrained and cannot, or will not, accept delivery of the gas due to downstream constraints on the pipeline or changes in interstate pipeline gas quality specifications, we may be forced to limit or stop the flow of gas through our pipelines and processing and treating facilities. In addition, interruption of pipeline service upstream of our processing facilities would limit or stop flow through our processing and fractionation facilities. Likewise, if the pipelines into which we deliver NGLs are interrupted, we may be limited in, or prevented from conducting, our NGL transportation operations. Any number of factors beyond our control could cause such interruptions or constraints on pipeline service, including necessary and scheduled maintenance, or unexpected damage to the pipelines. Because our revenues and net operating margins depend upon (i) the volumes of natural gas we process, gather and transmit, (ii) the throughput of NGLs through our transportation, fractionation and storage facilities and (iii) the volume of natural gas we gather and transport, any reduction of volumes could adversely affect our operations and cash flows available for distribution to our unitholders.

Table of Contents

Item 6. ***Exhibits***

Exhibit Number		Description
2.1	*	Contribution Agreement, dated November 2, 2012, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (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 November 6, 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).
3.3	*	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.4	*	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated as of January 20, 2009 and Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.5	*	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP, dated as of April 11, 2008 (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 April 14, 2008).
3.6	*	Amendment No. 2 to the Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
4.1	*	Registration Rights Agreement by and among DCP Midstream Partners, LP and the purchasers named therein dated July 2, 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 July 9, 2012).
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).
10.2	*	Term Loan Agreement by and among DCP Midstream Operating, LP, DCP Midstream Partners, LP and SunTrust Bank as Administrative Agent dated July 2, 2012 (attached as Exhibit 10.2 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on July 9, 2012).
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12.1		Ratio of Earnings to Fixed Charges.
31.1		Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2		Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1		Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2		Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101		Financial statements from the Quarterly Report on Form 10-Q of DCP Midstream Partners, LP for the three and nine months ended September 30, 2012, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity and (vi) the Notes to the Condensed Consolidated Financial Statements.

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on November 7, 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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* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES

The table below sets forth the calculation of Ratios of Earnings to Fixed Charges:

	DCP Midstream Partners, LP					
	Nine Months Ended September 30,	Year Ended December 31,				
	2012	2011	2010	2009	2008	2007
	(Millions)					
Earnings from continuing operations before fixed charges:						
Pretax income (loss) from continuing operations before earnings from unconsolidated affiliates	$ 88.8	$ 98.6	$ 68.9	$(11.4)	$159.2	$ 8.9
Fixed charges	37.0	36.0	29.9	30.3	33.6	27.0
Amortization of capitalized interest	0.4	0.2	0.1	0.1	0.1	—
Distributed earnings from unconsolidated affiliates	15.9	22.7	23.8	18.6	18.2	23.5
Less:						
Capitalized interest	(4.9)	(1.6)	(0.2)	(1.3)	(0.3)	(0.2)
Earnings from continuing operations before fixed charges	$ 137.2	$155.9	$122.5	$ 36.3	$210.8	$59.2
Fixed charges:						
Interest expense, net of capitalized interest	$ 31.6	$ 33.2	$ 28.8	$ 28.3	$ 32.6	$26.0
Capitalized interest	4.9	1.6	0.2	1.3	0.3	0.2
Estimate of interest within rental expense	0.3	0.5	0.6	0.5	0.5	0.6
Amortization of deferred loan costs	0.2	0.7	0.3	0.2	0.2	0.2
Total fixed charges	$ 37.0	$ 36.0	$ 29.9	$ 30.3	$ 33.6	$27.0
Ratio of earnings to fixed charges	3.71	4.33	4.10	1.20	6.27	2.19

For purposes of determining the ratio of earnings to fixed charges, earnings are defined as pretax income or loss from continuing operations before earnings from unconsolidated affiliates, plus fixed charges, plus distributed earnings from unconsolidated affiliates, less capitalized interest. Fixed charges consist of interest expensed, capitalized interest, amortization of deferred loan costs, and an estimate of the interest within rental expense.

Exhibit 31.1

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

I, Mark A. Borer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three and nine months ended September 30, 2012;

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

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

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

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

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

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

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

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

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

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

Date: November 7, 2012

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

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

I, Rose M. Robeson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three and nine months ended September 30, 2012;

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

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

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

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

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

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

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

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

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

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

Date: November 7, 2012

/s/ Rose M. Robeson
Rose M. Robeson
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

Certification of Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

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

(a) the quarterly report on Form 10-Q of the Partnership for the three and nine months ended September 30, 2012, filed on the date hereof with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer
(Principal Executive Officer)
November 7, 2012

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

Certification of Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

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

(a) the quarterly report on Form 10-Q of the Partnership for the three and nine months ended September 30, 2012, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

/s/ Rose M. Robeson
Rose M. Robeson
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)
November 7, 2012

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