DCP Midstream Partners, LP
Form 10-Q
May 10, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2011

or

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

For the transition period from to

Commission File Number: 001-32678

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

As of May 6, 2011, there were outstanding 44,083,418 common units representing limited partner interests.

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DCP MIDSTREAM PARTNERS, LP

FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2011

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GLOSSARY OF TERMS

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

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

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in Item 1A. Risk Factors in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2010, as well as the following risks and uncertainties:

- the extent of changes in commodity prices, our ability to effectively limit a portion of the adverse impact of potential changes in prices through derivative financial instruments, and the potential impact of price 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 acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets 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 to our credit agreement and our debt securities, as well as our ability to maintain our credit ratings;
- our ability to purchase propane from our principal suppliers and make associated profitable sales transactions for our wholesale propane logistics business;
- our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required construction, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for supplies;
- the creditworthiness of counterparties to our transactions;

- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third-party-owned infrastructure;
- new, additions to and changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment, including climate change legislation, or the increased regulation of our industry;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- industry changes, including the impact of consolidations, increased delivery of liquefied natural gas to the United States, alternative energy sources, technological advances and changes in competition; and
- the amount of collateral we may be required to post from time to time in our transactions 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. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	March 31, 2011	December 31, 2010
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5.0	$ 6.7
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.5 million for each period	81.1	89.3
Affiliates	69.4	61.7
Inventories	42.1	64.1
Unrealized gains on derivative instruments	0.9	1.9
Assets held for sale		6.2
Other	1.4	2.1
Total current assets	199.9	232.0
Property, plant and equipment, net	1,120.6	1,097.1
Goodwill	146.8	139.3
Intangible assets, net	117.8	119.3
Investments in unconsolidated affiliates	216.0	216.9
Unrealized gains on derivative instruments	3.1	1.4
Other long-term assets	7.1	7.2
Total assets	$ 1,811.3	$ 1,813.2
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 89.1	$ 99.1
Affiliates	31.1	37.6
Unrealized losses on derivative instruments	54.3	43.0
Taxes payable	39.5	
Other	25.8	31.5
Total current liabilities	239.8	211.2
Long-term debt	675.8	647.8
Unrealized losses on derivative instruments	69.2	50.3
Other long-term liabilities	15.7	53.1
Total liabilities	1,000.5	962.4
Commitments and contingent liabilities		

Equity:		
Predecessor equity		112.6
Common unitholders (44,083,418 and 40,478,383 units issued and outstanding, respectively)	619.0	552.2
General partner	(6.0)	(6.4)
Accumulated other comprehensive loss	(23.3)	(27.7)
Total partners equity	589.7	630.7
Noncontrolling interests	221.1	220.1
Total equity	810.8	850.8
Total liabilities and equity	$ 1,811.3	$ 1,813.2

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended March 31,	
	2011	**2010**
	(Millions, except per unit amounts)	
Operating revenues:		
Sales of natural gas, propane, NGLs and condensate	$ 297.5	$ 235.4
Sales of natural gas, propane, NGLs and condensate to affiliates	132.2	135.0
Transportation, processing and other	30.5	21.6
Transportation, processing and other to affiliates	5.1	5.7
(Losses) gains from commodity derivative activity, net	(38.9)	6.0
Losses from commodity derivative activity, net affiliates	(1.3)	
Total operating revenues	425.1	403.7
Operating costs and expenses:		
Purchases of natural gas, propane and NGLs	222.3	191.5
Purchases of natural gas, propane and NGLs from affiliates	152.7	141.3
Operating and maintenance expense	24.1	19.0
Depreciation and amortization expense	19.9	17.8
General and administrative expense	4.2	3.7
General and administrative expense affiliates	4.8	4.9
Other income	(0.1)	
Total operating costs and expenses	427.9	378.2
Operating (loss) income	(2.8)	25.5
Interest expense	(8.0)	(7.2)
Earnings from unconsolidated affiliates	8.6	14.4
(Loss) income before income taxes	(2.2)	32.7
Income tax expense	(0.2)	(0.3)
Net (loss) income	(2.4)	32.4
Net income attributable to noncontrolling interests	(3.5)	(0.1)
Net (loss) income attributable to partners	(5.9)	32.3
Net loss attributable to predecessor operations		(6.5)
General partner s interest in net income	(5.5)	(3.8)
Net (loss) income allocable to limited partners	$ (11.4)	$ 22.0
Net (loss) income per limited partner unit basic	$ (0.28)	$ 0.64
Net (loss) income per limited partner unit diluted	$ (0.28)	$ 0.64
Weighted-average limited partner units outstanding basic	41.3	34.6

Weighted-average limited partner units outstanding diluted	41.3	34.6

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended March 31, 2011	2010
	(Millions)	
Net (loss) income	$ (2.4)	$ 32.4
Other comprehensive income (loss):		
Reclassification of cash flow hedge losses into earnings	5.3	6.0
Net unrealized losses on cash flow hedges	(0.9)	(7.6)
Total other comprehensive income (loss)	4.4	(1.6)
Total comprehensive income	2.0	30.8
Total comprehensive income attributable to noncontrolling interests	(3.5)	(0.1)
Total comprehensive income attributable to partners	$ (1.5)	$ 30.7

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31, 2011	2010
	(Millions)	
OPERATING ACTIVITIES:		
Net (loss) income	$ (2.4)	$ 32.4
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation and amortization expense	19.9	17.8
Earnings from unconsolidated affiliates	(8.6)	(14.4)
Distributions from unconsolidated affiliates	11.3	12.5
Other, net	2.3	0.5
Change in operating assets and liabilities, which provided (used) cash net of effects of acquisitions:		
Accounts receivable	0.5	31.9
Inventories	22.0	(8.9)
Net unrealized losses (gains) on derivative instruments	33.9	(7.8)
Accounts payable	(15.1)	(9.3)
Accrued interest	2.1	
Other current assets and liabilities	0.1	(0.9)
Other long-term assets and liabilities	(2.0)	(0.1)
Net cash provided by operating activities	64.0	53.7
INVESTING ACTIVITIES:		
Capital expenditures	(13.7)	(12.2)
Acquisitions, net of cash acquired	(37.1)	(22.0)
Acquisition of unconsolidated affiliate	(114.3)	
Investments in unconsolidated affiliates	(0.1)	(0.7)
Proceeds from sale of assets	0.2	0.2
Proceeds from sales of available-for-sale securities		10.1
Net cash used in investing activities	(165.0)	(24.6)
FINANCING ACTIVITIES:		
Proceeds from debt	547.0	116.6
Payments of debt	(519.0)	(114.6)
Payment of deferred financing costs	(0.1)	
Proceeds from issuance of common units, net of offering costs	139.7	
Excess purchase price over acquired assets	(35.7)	
Net change in advances to predecessor from DCP Midstream, LLC		(2.7)
Distributions to unitholders and general partner	(30.1)	(24.6)
Distributions to noncontrolling interests	(5.4)	(3.7)
Contributions from noncontrolling interests	2.9	3.9
Purchase of additional interest in a subsidiary		(3.5)
Net cash provided by (used in) financing activities	99.3	(28.6)
Net change in cash and cash equivalents	(1.7)	0.5
Cash and cash equivalents, beginning of period	6.7	2.1

Cash and cash equivalents, end of period	$ 5.0	$ 2.6

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Unaudited)

		Partner s Equity				
	Predecessor Equity	Common Unitholders	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
			(Millions)			
Balance, January 1, 2011	$ 112.6	$ 552.2	$ (6.4)	$ (27.7)	$ 220.1	$ 850.8
Net change in parent advances	1.7					1.7
Acquisition of Southeast Texas	(114.3)					(114.3)
Excess purchase price over acquired assets		(35.7)				(35.7)
Issuance of 3,596,636 common units		139.6				139.6
Equity-based compensation		1.9				1.9
Distributions to DCP Midstream, LLC		(2.6)				(2.6)
Distributions to unitholders and general partner		(25.0)	(5.1)			(30.1)
Distributions to noncontrolling interests					(5.4)	(5.4)
Contributions from noncontrolling interests					2.9	2.9
Comprehensive income (loss):						
Net income		(11.4)	5.5		3.5	(2.4)
Reclassification of cash flow hedges into earnings				5.3		5.3
Net unrealized losses on cash flow hedges				(0.9)		(0.9)
Total comprehensive (loss) income		(11.4)	5.5	4.4	3.5	2.0
Balance, March 31, 2011	$	$ 619.0	$ (6.0)	$ (23.3)	$ 221.1	$ 810.8

		Partner s Equity				
	Predecessor Equity	Common Unitholders	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2010	$ 70.8	$ 415.5	$ (5.9)	$ (31.9)	$ 227.7	$ 676.2
Net change in parent advances	(2.7)					(2.7)
Purchase of additional interest in a subsidiary		1.0			(5.5)	(4.5)
Distributions		(20.8)	(3.8)		(3.7)	(28.3)
Contributions					3.9	3.9
Comprehensive income (loss):						
Net income attributable to predecessor operations	6.5					6.5
Net income		21.9	3.9		0.1	25.9
Reclassification of cash flow hedge losses into earnings				6.0		6.0
Net unrealized losses on cash flow hedges				(7.6)		(7.6)
Total comprehensive income (loss)	6.5	21.9	3.9	(1.6)	0.1	30.8

Balance, March 31, 2010	$	74.6	$	417.6	$	(5.8)	$	(33.5)	$ 222.5	$	675.4

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, is engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; and producing, 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 Northern Louisiana system; our Southern Oklahoma system; our 40% limited liability company 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 (of which 5% was acquired in February 2010); our 50.1% interest in our DCP East Texas Holdings, LLC, or our East Texas system; our Michigan system; our 33.33% interest in our DCP Southeast Texas Holdings, GP, or our Southeast Texas system acquired in January 2011; our wholesale propane logistics business (which includes Atlantic Energy acquired in July 2010); and our NGL logistics business (which includes Marysville Hydrocarbons Holdings, Inc, or Marysville, acquired in December 2010, the Wattenberg pipeline acquired in January 2010 and our 100% interest in the Black Lake Pipeline Company, or Black Lake, 55% of which was acquired in July 2010, comprised of: (1) a 5% interest acquired from DCP Midstream, LLC, in a transaction among entities under common control, and (2) an additional 50% interest acquired from an affiliate of BP PLC).

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 ConocoPhillips. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC and its affiliates employees provide administrative support to us and operate most of our assets. DCP Midstream, LLC owns approximately 27% of us.

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

On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million, in a transaction among entities under common control. Transfers of net assets between entities under common control 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 equity interest in Southeast Texas for all periods presented. We refer to our 33.33% interest in Southeast Texas, prior to our acquisition from DCP Midstream, LLC in January 2011, 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 of DCP Midstream, LLC s basis in the net assets is recognized as a reduction 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.

The results of operations for acquisitions accounted for as business combinations have been included in the condensed consolidated financial statements since their respective acquisition dates and we have retrospectively adjusted the December 31, 2010 condensed consolidated balance sheet for changes in our preliminary purchase price allocation for our December 31, 2010 acquisition of Marysville.

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 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 months ended March 31, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011. These condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the consolidated financial statements and notes thereto included in our 2010 Form 10-K.

2. Recent Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2010-29 Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations , or ASU 2010-29 In December 2010, the FASB issued ASU 2010-29 which amended Accounting Standards Codification, or ASC, Topic 805 Business Combinations to specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the year had occurred as of the beginning of the comparable prior annual reporting period only. The ASU also expands the supplemental pro forma disclosures under Topic 805 to include a description of the nature and the amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after January 1, 2011. The provisions of ASU 2010-29 impact disclosure only. We have not had any business combinations that fall under the guidance of ASU 2010-29 and consequently, there was no impact on our disclosures as a result of adoption.

ASU 2010-28 Intangibles Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts , or ASU 2010-28 In December 2010, the FASB issued ASU 2010-28 which amended ASC Topic 350 Intangibles Goodwill and Other . ASU 2010-28 requires an entity with reporting units that have carrying amounts that are zero or negative to assess whether it is more likely than not that the reporting units goodwill is impaired. If the entity determines that it is more likely than not that the goodwill of one or more of its reporting units is impaired, the entity is required to perform Step 2 of the goodwill impairment test for those reporting unit(s) and record any resulting impairment as a cumulative-effect adjustment to beginning retained earnings. The provisions of ASU 2010-28 became effective for us on January 1, 2011. We do not have any reporting units that fall under the guidance of ASU 2010-28 and consequently, there was no effect on our condensed consolidated results of operations, cash flows or financial position as a result of adoption.

ASU, 2010-06 Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements , or ASU 2010-06 In January 2010, the FASB issued ASU 2010-06 which amended ASC Topic 820-10 Fair Value Measurement and Disclosures Overall. ASU 2010-06 requires new disclosures regarding transfers in and out of assets and liabilities measured at fair value classified within the valuation hierarchy as either Level 1 or Level 2 and information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3. ASU 2010-06 clarifies existing disclosures on the level of disaggregation required and inputs and valuation techniques. The provisions of ASU 2010-06 became effective for us on January 1, 2010, except for disclosure of information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3, which became effective for us on January 1, 2011. The provisions of ASU 2010-06 impact only disclosures and we have disclosed information in accordance with the provisions of ASU 2010-06 within this filing.

ASU 2009-13 Revenue Recognition (Topic 605) Multiple-Deliverable Revenue Arrangements , or ASU 2009-13 In October 2009, the FASB issued ASU 2009-13 which amended ASC Topic 605 Revenue Recognition. The ASU addresses the accounting for multiple-deliverable arrangements, to enable vendors to account for products or services separately rather than as a combined unit. ASU 2009-13 became effective for us on January 1, 2011 and there was no impact on our condensed consolidated results of operations, cash flows and financial position as a result of adoption.

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3. Acquisitions

On March 24, 2011, we acquired two NGL fractionation facilities in Weld County, Colorado, located in the Denver-Julesburg, or DJ, Basin, from a third party in a transaction accounted for as an asset acquisition. We paid a purchase price of $30.0 million, financed initially at closing with borrowings under the Partnership s revolving credit facility, and received a post-closing purchase price adjustment of $0.4 million. The NGL fractionation facilities, or the DJ Basin NGL Fractionators, are located on DCP Midstream, LLC s processing plant sites and are operated by DCP Midstream, LLC. Subsequent to our acquisition, DCP Midstream, LLC will continue to operate and supply certain committed NGLs produced by them in Weld County to our DJ Basin NGL Fractionators under the existing agreements that are effective through March 2018. The results of the assets are included in our NGL Logistics segment prospectively, from the date of acquisition.

On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million, in a transaction among entities under common control, financed initially at closing with proceeds from our November 2010 public equity offering and borrowings under the Partnership s revolving credit facility. DCP Midstream, LLC s historical carrying value of the net assets acquired in the acquisition was $114.3 million; accordingly we have recorded the $35.7 million excess purchase price over acquired assets as a decrease in common unitholders equity. The results of our 33.33% interest in Southeast Texas are included in our Natural Gas Services segment for all periods presented.

On December 30, 2010, we acquired all of the interests in Marysville. The acquisition involved three separate transactions with a number of parties. We acquired a 90% interest in Marysville from Dart Energy Corporation, a 5% interest in Marysville from Prospect Street Energy, LLC and 100% of EE Group, LLC, which owned the remaining 5% interest in Marysville. We paid a purchase price of $94.8 million plus $6.0 million for net working capital and other adjustments for an aggregate purchase price of $100.8 million, subject to customary purchase price adjustments, for our 100% interest. The cash purchase was financed initially at closing with borrowings under the Partnership s revolving credit facility. $21.2 million of the purchase price has been deposited in an indemnity escrow to satisfy certain tax liabilities and provide for breaches of representations and warranties of the sellers. The results of the Marysville acquisition are included in our NGL Logistics segment prospectively, from the date of acquisition.

On January 4, 2011, we merged two wholly-owned subsidiaries of Marysville and converted the combined entity s organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggered tax liabilities, resulting from built-in tax gains recognized in the transaction, to become currently payable. Accordingly, $35.0 million of estimated deferred tax liabilities associated with this transaction and recorded at December 31, 2010, became currently payable as of January 4, 2011. These tax liabilities are unrelated to the tax liabilities of Marysville for which an indemnity escrow has been established. These tax liabilities may be greater or less than the $35.0 million currently recorded in our balance sheet as of March 31, 2011, depending on the final accounting for the Marysville business combination.

We have updated our accounting for the Marysville business combination for the fair value of assets acquired and liabilities assumed including intangible assets and property, plant and equipment and goodwill. The December 31, 2010 condensed consolidated balance sheet included in this report has been retrospectively adjusted to reflect the impact of this change. 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 and the final outcome of our estimated tax liabilities. The preliminary purchase price allocation as of December 31, 2010 compared to the preliminary purchase price allocation as of March 31, 2011 is as follows:

	December 31, 2010	March 31, 2011 (Millions)	Change
Aggregate consideration	$ 100.8	$ 100.8	$
Cash	3.1	3.1	
Accounts receivable	1.1	1.1	
Inventory	5.7	4.6	(1.1)
Other current assets	0.7	0.7	
Property, plant and equipment	129.9	57.9	(72.0)
Intangible assets		32.3	32.3
Goodwill		39.6	39.6
Other long-term assets		1.2	1.2
Other current liabilities	(4.7)	(4.7)	

Long-term liabilites		(35.0)		(35.0)	
Total preliminary purchase price allocation	$	100.8	$	100.8	$

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Combined Financial Information

The results of our 33.33% interest in Southeast Texas and the impact of the Marysville preliminary purchase price allocation adjustments are included in the condensed consolidated balance sheets as of March 31, 2011 and December 31, 2010. The following table presents the previously reported December 31, 2010 condensed consolidated balance sheet, adjusted for the acquisition of a 33.33% interest in Southeast Texas from DCP Midstream, LLC and the impact of adjustments to the preliminary purchase price allocation for Marysville:

As of December 31, 2010

	DCP Midstream Partners, LP (As previously reported)	Marysville	Southeast Texas (a)	Combined DCP Midstream Partners, LP (As currently reported)
	(Millions)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 6.7	$	$	$ 6.7
Accounts receivable	151.0			151.0
Inventories	65.2	(1.1)		64.1
Other	10.2			10.2
Total current assets	233.1	(1.1)		232.0
Property, plant and equipment, net	1,169.1	(72.0)		1,097.1
Goodwill and intangible assets, net	186.7	71.9		258.6
Investments in unconsolidated affiliates	104.3		112.6	216.9
Other non-current assets	7.4	1.2		8.6
Total assets	$ 1,700.6	$	$ 112.6	$ 1,813.2
LIABILITIES AND EQUITY				
Accounts payable and other current liabilities	$ 211.2	$	$	$ 211.2
Long-term debt	647.8			647.8
Other long-term liabilities	103.4			103.4
Total liabilities	962.4			962.4
Commitments and contingent liabilities				
Equity:				
Partners equity				
Predecessor equity (a)			112.6	112.6
Net equity	545.8			545.8
Accumulated other comprehensive income	(27.7)			(27.7)
Total partners equity	518.1		112.6	630.7
Noncontrolling interests	220.1			220.1
Total equity	738.2		112.6	850.8
Total liabilities and equity	$ 1,700.6	$	$ 112.6	$ 1,813.2

(a) The carrying value of our 33.33% interest in Southeast Texas was $112.6 million as of December 31, 2010. As part of the closing of our acquisition on January 1, 2011, we acquired a 33.33% interest in Southeast Texas, with the exception of net liabilities of $1.7 million consisting of financial derivative instruments and certain working capital and other liabilities. Accordingly, we recognized an increase to predecessor equity of $1.7 million in our condensed consolidated statement of changes in equity, thereby reflecting the total carrying value of the net assets acquired on January 1, 2011 as $114.3 million.

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The results of our 33.33% interest in Southeast Texas are included in the condensed consolidated statements of operations for the three months ended March 31, 2011 and March 31, 2010. The following table presents the previously reported condensed consolidated statements of operations for the three months ended March 31, 2010, adjusted for the acquisition of a 33.33% interest in Southeast Texas from DCP Midstream, LLC:

Three Months Ended March 31, 2010

	DCP Midstream Partners, LP (As previously reported)	Southeast Texas (a) (Millions)	Combined DCP Midstream Partners, LP (As currently reported)
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 370.4	$	$ 370.4
Transportation, processing and other	27.3		27.3
Gains from commodity derivative activity, net	6.0		6.0
Total operating revenues	403.7		403.7
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	332.8		332.8
Operating and maintenance expense	19.0		19.0
Depreciation and amortization expense	17.8		17.8
General and administrative expense and other	8.6		8.6
Total operating costs and expenses	378.2		378.2
Operating income	25.5		25.5
Interest expense, net	(7.2)		(7.2)
Earnings from unconsolidated affiliates	7.9	6.5	14.4
Income before income taxes	26.2	6.5	32.7
Income tax expense	(0.3)		(0.3)
Net income	25.9	6.5	32.4
Net income attributable to noncontrolling interests	(0.1)		(0.1)
Net income attributable to partners	$ 25.8	$ 6.5	$ 32.3

(a) The results of our 33.33% interest in Southeast Texas for the three months ended March 31, 2010 includes the impact of Hurricane Ike business interruption insurance recoveries of $1.5 million.

The results of operations for acquisitions accounted for as a business combination are included in the DCP Midstream Partners, LP results subsequent to the date of acquisition. Accordingly, total operating revenues of $8.0 million and net income attributable to the Partnership of $5.8 million associated with Marysville are included in the condensed consolidated statement of operations for the three months ended March 31, 2011. Pro forma information is presented for comparative periods prior to the date of acquisition, however, comparative periods are not adjusted to include the results of the acquisition.

The following table presents unaudited pro forma information for the condensed consolidated statement of operations for the three months ended March 31, 2010, as if the acquisition of Marysville had occurred at the beginning of the period presented.

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	Three Months Ended, March 31, 2010		
	DCP Midstream Partners, LP	Acquisition of Marysville	DCP Midstream Partners, LP Pro Forma
	(Millions, except per unit amounts)		
Total operating revenues	$ 403.7	$ 8.6	$ 412.3
Net income attributable to partners	$ 32.3	$ 4.0	$ 36.3
Less:			
Net income attributable to predecessor operations	(6.5)		(6.5)
General partner unitholders interest in net income	(3.8)		(3.8)
Net income allocable to limited partners	$ 22.0	$ 4.0	$ 26.0
Net income per limited partner unit basic and diluted	$ 0.64	$ 0.12	$ 0.76

The pro forma information is 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.

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 2011, we extended the omnibus agreement through December 31, 2011 for an annual amount of $10.2 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 March 31,	
	2011	2010
	(Millions)	
Omnibus Agreement	$ 2.5	$ 2.5
Other fees DCP Midstream, LLC	2.2	2.3
Total DCP Midstream, LLC	$ 4.7	$ 4.8

Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC for certain costs incurred and centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. The Omnibus Agreement also addresses the following matters:

- DCP Midstream, LLC s obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities; and

- DCP Midstream, LLC s obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts.

Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions, will be terminable by DCP Midstream, LLC at its option if the general partner is removed without cause and units held by the general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a change of control of us, the general partner (DCP Midstream GP, LP) or the General Partner (DCP Midstream GP, LLC).

East Texas incurs general and administrative expenses directly from DCP Midstream, LLC. During the three months ended March 31, 2011 and 2010, East Texas incurred $1.9 million and $2.0 million, respectively, for general and administrative expenses from DCP Midstream, LLC.

In addition to the Omnibus Agreement and amounts incurred by East Texas, we incurred other general and administrative fees with DCP Midstream, LLC of $0.3 million for each of the three months ended March 31, 2011 and 2010. These amounts include allocated expenses, including professional services, insurance and internal audit.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC was a significant customer during the three months ended March 31, 2011 and 2010.

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 to DCP Midstream, LLC in the ordinary course of business. In addition, DCP Midstream, LLC conducts derivative activities on our behalf.

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, 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 a firm 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 acquisition of a 33.33% interest in Southeast Texas from DCP Midstream, LLC for $150.0 million in our Natural Gas Services segment, we entered into a joint venture agreement. The terms of the joint venture agreement provide that distributions and earnings to us for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions and earnings related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Midstream, LLC s respective ownership interests in Southeast Texas. This transaction closed on January 1, 2011.

In conjunction with our acquisition of a 50.1% limited liability company interest in East Texas, which is part of our Natural Gas Services segment, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for certain expenditures on East Texas capital projects. These reimbursements are for certain capital projects which have commenced within three years from the respective acquisition dates. DCP Midstream, LLC made capital contributions to East Texas for capital projects of $2.9 million and $3.8 million for the three months ended March 31, 2011 and 2010, respectively.

On September 16, 2010, we entered into an agreement with DCP Midstream, LLC to sell certain surplus equipment at Collbran, part of our Natural Gas Services segment, with a net book value of $6.2 million for net proceeds of $3.6 million. The surplus equipment is the result of a consolidation of operations at our Anderson Gulch plant in the Piceance Basin. The net proceeds of $3.6 million were distributed 75% to us and 25% to the noncontrolling interest in Collbran, based upon proportionate ownership, during the year ended December 31, 2010. The sale was completed when title to the surplus equipment passed to DCP Midstream, LLC in March 2011. We have recognized a distribution of $2.6 million for the three months ended March 31, 2011 to DCP Midstream, LLC in our condensed consolidated statements of changes in equity representing the difference between the net book value and the proceeds received for the surplus equipment.

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On February 11, 2009, our East Texas natural gas processing complex and natural gas delivery system known as the Carthage Hub, was temporarily shut in following a fire that was caused by a third party underground pipeline rupture outside of our property. We are actively pursuing full reimbursement of our costs and lost margin associated with the incident from the responsible third party. East Texas filed a lawsuit in December 2009, to recover damages from the responsible third party. In the event we are unable to recover our costs and lost margin from the responsible third party, we have insurance covering property damage, net of applicable deductibles. Following this incident, DCP Midstream, LLC has agreed to reimburse to us 25% of any claims received as reimbursement of costs and lost margin, from the responsible third party or from insurance. DCP Midstream, LLC will pay 75% of costs related to the incident as a result of this agreement.

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

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

In conjunction with our acquisition of the Wattenberg pipeline, which is part of our NGL Logistics segment, we signed a transportation agreement with DCP Midstream, LLC pursuant to fee-based rates that will be applied to the volumes transported, which was effective through December 31, 2010. 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.

In conjunction with our acquisition of our DJ Basin NGL Fractionators in our NGL Logistics segment, 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 at our DJ Basin NGL Fractionators under agreements that are effective through March 2018.

DCP Midstream, LLC has issued parental guarantees, totaling $85.0 million as of March 31, 2011, 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 interest of 0.5% per annum on these outstanding guarantees.

DCP Midstream, LLC has issued parental guarantees for its 49.9% limited liability company interest in East Texas, totaling $6.0 million as of March 31, 2011, in favor of certain counterparties to processing and transportation agreements at East Texas. Concurrently, we issued similar guarantees for our 50.1% interest.

Spectra Energy

We have a propane supply agreements with Spectra Energy, effective through April 2012, which provides us propane supply at our marine terminals, which are included in our Wholesale Propane Logistics segment, for up to approximately 185 million gallons of propane annually. Additionally, we have transportation agreements with Spectra Energy, effective through January 2012, which provide natural gas transportation to our Pelico system in our Natural Gas Services segment, for approximately 35 MMcf/d.

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ConocoPhillips

We have multiple agreements with ConocoPhillips and its affiliates. The agreements include fee-based and percent-of-proceeds gathering and processing arrangements, and gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We did not receive any capital reimbursements during the three months ended March 31, 2011 or 2010.

Summary of Transactions with Affiliates

The following table summarizes transactions with affiliates:

	Three Months Ended March 31,	
	2011	2010
	(Millions)	
DCP Midstream, LLC:		
Sales of natural gas, propane, NGLs and condensate	$ 131.1	$ 133.6
Transportation, processing and other	$ 3.2	$ 3.8
Purchases of natural gas, propane and NGLs	$ 63.0	$ 62.8
Losses from commodity derivative activity, net	$ 1.3	$
General and administrative expense	$ 4.7	$ 4.8
Interest expense	$	$ 0.1
Spectra Energy:		
Purchases of natural gas, propane and NGLs	$ 85.2	$ 74.1
ConocoPhillips:		
Sales of natural gas, propane, NGLs and condensate	$ 1.1	$ 1.4
Transportation, processing and other	$ 1.9	$ 1.9
Purchases of natural gas, propane and NGLs	$ 1.4	$ 2.0
General and administrative expense	$ 0.1	$ 0.1
Unconsolidated affiliates:		
Purchases of natural gas, propane and NGLs	$ 3.1	$ 2.4

We had balances with affiliates as follows:

	March 31, 2011	December 31, 2010
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 67.2	$ 60.1
Accounts payable	$ 27.7	$ 27.0
Unrealized gains on derivative instruments current	$	$ 1.3
Unrealized losses on derivative instruments current	$ (1.2)	$ (1.8)
Spectra Energy:		
Accounts payable	$ 2.2	$ 8.7
ConocoPhillips:		
Accounts receivable	$ 2.2	$ 1.6
Accounts payable	$ 0.5	$ 1.0
Unconsolidated affiliates:		
Accounts payable	$ 0.7	$ 0.9

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5. Property, Plant and Equipment

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

	Depreciable Life	March 31, 2011	December 31, 2010
		(Millions)	
Gathering and transmission systems	15 30 Years	$ 994.1	$ 992.0
Processing, storage, and terminal facilities	20 50 Years	543.0	513.2
Other	0 30 Years	14.7	12.6
Construction work in progress		50.7	42.1
Property, plant and equipment		1,602.5	1,559.9
Accumulated depreciation		(481.9)	(462.8)
Property, plant and equipment, net		$ 1,120.6	$ 1,097.1

Interest capitalized on construction projects for the three months ended March 31, 2011 was $0.2 million and for the year ended December 31, 2010 was $0.2 million.

Depreciation expense was $18.4 million and $17.0 million for the three months ended March 31, 2011 and 2010, respectively.

Asset Retirement Obligations As of March 31, 2011, we had asset retirement obligations of $10.9 million included in other long-term liabilities in the consolidated balance sheets. As of December 31, 2010, we had asset retirement obligations of $10.8 million included in other long-term liabilities in the consolidated balance sheets. Accretion expense for the three months ended March 31, 2011 and 2010 was $0.2 million and $0.1 million, respectively.

6. Goodwill and Intangible Assets

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

	March 31, 2011	December 31, 2010
	(Millions)	
Beginning of period	$ 139.3	$ 92.1
Acquisitions	7.5	47.2
End of period	$ 146.8	$ 139.3

The carrying value of goodwill as of March 31, 2011 and December 31, 2010 was $70.3 million and $62.8 million, respectively, for our Natural Gas Services segment, $36.9 million as of both periods for our Wholesale Propane Logistics segment, and $39.6 million as of both periods for our NGL logistics segment.

Goodwill increased in 2011 by $7.5 million as a result of a purchase price adjustment related to a contingent payment in conjunction with our 2008 Michigan System acquisition.

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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 are as follows:

	March 31, 2011	December 31, 2010
	(Millions)	
Gross carrying amount	$ 128.7	$ 128.7
Accumulated amortization	(10.9)	(9.4)
Intangible assets, net	$ 117.8	$ 119.3

For the three months ended March 31, 2011 and 2010, we recorded amortization expense of $1.5 million and $0.8 million, respectively. As of March 31, 2011, the remaining amortization periods ranged from approximately 11 years to 24 years, with a weighted-average remaining period of approximately 20 years.

The weighted-average remaining amortization is 20 years for the $32.3 million of intangible assets acquired with our acquisition of Marysville.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (Millions)
Remainder of 2011	$ 4.6
2012	6.0
2013	6.0
2014	6.0
2015	6.0
Thereafter	89.2
Total	$ 117.8

7. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage of Ownership as of March 31, 2011 and December 31, 2010	Carrying Value as of	
		March 31, 2011	December 31, 2010
		(Millions)	
Discovery Producer Services LLC	40%	$ 103.0	$ 104.1
Southeast Texas	33%	112.8	112.6
Other	50%	0.2	0.2
Total investments in unconsolidated affiliates		$ 216.0	$ 216.9

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $34.5 million and $35.1 million at March 31, 2011 and December 31, 2010, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended March 31,	
	2011	2010
	(Millions)	
Discovery Producer Services LLC	$ 4.5	$ 7.4
Southeast Texas	4.1	6.5
Black Lake Pipe Line Company (a)		0.5
Total earnings from unconsolidated affiliates	$ 8.6	$ 14.4

(a) As of March 31, 2010, we owned a 45% interest in Black Lake. On July 27, 2010, we acquired an additional 5% interest in Black Lake from DCP Midstream, LLC in a transaction among entities under common control, and on July 30, 2010, we acquired an additional 50% interest in Black Lake from an affiliate of BP PLC, bringing our ownership interest in Black Lake to 100%. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction, we account for Black Lake as a consolidated subsidiary.

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

	Three Months Ended March 31, 2011 (a)	Three Months Ended March 31, 2010 (b)
	(Millions)	
Statements of operations:		
Operating revenue	$ 259.9	$ 302.7
Operating expenses	$ 240.1	$ 264.7
Net income	$ 19.6	$ 37.9

(a) The combined financial information excludes the results of Black Lake, since we began accounting for Black Lake as a consolidated subsidiary effective July 30, 2010.
(b) The combined financial information for the three months ended March 31, 2010 includes the results of Southeast Texas as transfers of net assets between entities under common control 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.

	March 31, 2011 (a)	December 31, 2010 (a) (b)
	(Millions)	
Balance sheets:		
Current assets	$ 104.8	$ 153.0
Long-term assets	$ 693.6	684.9
Current liabilities	$ (83.8)	(121.4)
Long-term liabilities	$ (29.4)	(30.3)
Net assets	$ 685.2	$ 686.2

(a) The combined financial information excludes the results of Black Lake, since we began accounting for Black Lake as a consolidated subsidiary effective July 30, 2010.
(b) The combined financial information for the three months ended March 31, 2010 includes the results of Southeast Texas as transfers of net assets between entities under common control 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.

8. 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, 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. 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 10 Risk Management and Hedging Activities.

Valuation Hierarchy

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

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

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

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

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

Commodity Derivative Assets and Liabilities

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

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

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

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

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 floating rate debt for fixed rate debt. The swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR instrument. Given that a 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.

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The following table presents the financial instruments carried at fair value as of March 31, 2011 and December 31, 2010, by consolidated balance sheet caption and by valuation hierarchy as described above:

	March 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Commodity derivatives (a)	$	$ 0.7	$ 0.2	$ 0.9	$	$ 1.6	$ 0.3	$ 1.9
Long-term assets:								
Commodity derivatives (b)	$	$ 2.9	$ 0.2	$ 3.1	$	$ 1.1	$ 0.3	$ 1.4
Current liabilities (c):								
Commodity derivatives	$	$ (35.0)	$ (2.3)	$ (37.3)	$	$ (25.9)	$ (0.1)	$ (26.0)
Interest rate derivatives	$	$ (17.0)	$	$ (17.0)	$	$ (17.0)	$	$ (17.0)
Long-term liabilities (d):								
Commodity derivatives	$	$ (61.0)	$ (2.4)	$ (63.4)	$	$ (39.9)	$ (0.5)	$ (40.4)
Interest rate derivatives	$	$ (5.8)	$	$ (5.8)	$	$ (9.9)	$	$ (9.9)

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

Changes in Level 3 Fair Value Measurements

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

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

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Three months ended March 31, 2011 (a):				
Beginning balance	$ 0.3	$ 0.3	$ (0.1)	$ (0.5)
Net realized and unrealized losses included in earnings		(0.1)	(2.2)	(1.9)
Transfers into Level 3 (b)				
Transfers out of Level 3 (b)				
Settlements	(0.1)			
Ending balance	$ 0.2	$ 0.2	$ (2.3)	$ (2.4)
Net unrealized losses still held included in earnings (c)	$	$ (0.1)	$ (2.2)	$ (1.9)
Three months ended March 31, 2010:				
Beginning balance	$ 0.4	$ 0.2	$ (0.8)	$ (0.4)
Net realized and unrealized (losses) gains included in earnings	1.2	1.0	(0.1)	
Transfers into Level 3 (b)				
Transfers out of Level 3 (b)				
Purchases, Issuances and Settlements net	(0.1)		0.6	
Ending balance	$ 1.5	$ 1.2	$ (0.3)	$ (0.4)
Net unrealized gains still held included in earnings (c)	$ 1.2	$ 1.0	$ 0.4	$

(a) There were no purchases, issuances and sales for the three months ended March 31, 2011.
(b) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(c) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains or losses relating to assets and liabilities classified as Level 3 that are still held as of March 31, 2011 and 2010.

During the three months ended March 31, 2010, we recognized the fair value of our contingent consideration, which is classified as Level 3, in relation to our acquisition of an additional 5% interest in Collbran, from Delta Petroleum Corporation of approximately $1.0 million, which we recorded to other current liabilities in our condensed consolidated balance sheets.

During the three months ended March 31, 2011, we had no significant transfers into and out of Levels 1, 2 and 3. 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.

Estimated Fair Value of Financial Instruments

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. The carrying and fair values of outstanding balances under our Credit

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Agreement are $426.0 million, and $419.4 million, respectively, as of March 31, 2011, and $398.0 million and $388.9 million, respectively, as of December 31, 2010. The carrying and fair values of our 3.25% Senior Notes are $250.0 million and $246.0 million, respectively, as of March 31, 2011 and $250.0 million and $247.0 million, respectively, as of December 31, 2010. 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.

9. Debt

Long-term debt was as follows:

	March 31, 2011	December 31, 2010
	(Millions)	
Credit Agreement		
Revolving credit facility, weighted-average variable interest rate of 0.73% and 1.14%, respectively, and net effective interest rate of 4.61% and 4.28%, respectively, due June 21, 2012 (a)	$ 426.0	$ 398.0
Debt Securities		
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250.0	250.0
Unamortized discount	(0.2)	(0.2)
Total long-term debt	$ 675.8	$ 647.8

(a) $425.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.94% to 5.19%, for a net effective rate of 4.61% on the $426.0 million of outstanding debt under our revolving credit facility as of March 31, 2011.

Credit Agreement

We have an $850.0 million revolving credit facility that matures June 21, 2012, or the Credit Agreement.

At March 31, 2011 and December 31, 2010, we had $0.5 million and $32.1 million, respectively, of letters of credit issued and outstanding under the Credit Agreement. As of March 31, 2011, the unused capacity under the revolving credit facility was $423.5 million, of which approximately $365.0 million was available for general working capital purposes.

Our borrowing capacity is limited at March 31, 2011 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 June 21, 2012 maturity date.

Under the Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wells Fargo Bank s prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

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

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Debt Securities

On September 30, 2010, we issued $250.0 million of 3.25% Senior Notes due October 1, 2015. We received proceeds, of $247.7 million, which are net of underwriters fees, related expenses and unamortized discounts of $1.5 million, $0.6 million and $0.2 million, respectively, which we used to repay funds borrowed under the revolver portion of our Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing April 1, 2011. The notes will mature on October 1, 2015, 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 these notes. The securities are redeemable at a premium at our option.

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

	Debt Maturities (Millions)
2011	$
2012	426.0
2013	
2014	
2015	250.0
Thereafter	
Unamortized discount	(0.2)
Total	$ 675.8

Other Agreements

As of March 31, 2011, we had a contingent letter of credit for up to $10.0 million, on which we pay a fee of 0.50% per annum. This facility reduces the amount of cash we may be required to post as collateral. As of March 31, 2011, we had no letters of credit issued on this facility. Any letters of credit issued on this facility will incur a fee of 1.75% per annum and will not reduce the available capacity under our credit facility.

10. Risk Management and Hedging Activities

Our day to day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures 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.

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Commodity Price Risk

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

With respect to our Pelico system, we may enter into financial derivatives to lock in transportation margins across the system, or to lock in margins around our leased storage facility to maximize value. This objective may be achieved through the use of physical purchases or sales of gas that are accounted for under accrual accounting. While the physical purchase or sale of gas transactions are accounted for under accrual accounting and any inventory is stated at lower of cost or market, the swaps are not designated as hedging instruments for accounting purposes and any change in fair value of these instruments is reflected within our condensed consolidated statements of operations.

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

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Commodity Cash Flow Hedges Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for derivatives that manage our commodity price risk. Prior to July 1, 2007, we used commodity swaps to mitigate a portion of the risk of market fluctuations in the price of NGLs, natural gas and condensate. Given our election to discontinue using the hedge method of accounting, the remaining net losses deferred in AOCI relative to cash flow hedges are reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the underlying transactions impact earnings.

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 to fixed interest rates. These 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 March 31, 2011, we had interest rate swap agreements totaling $450 million, of which we have designated $425.0 million as cash flow hedges and account for the remaining $25.0 million under the mark-to-market method of accounting. As we generally expect to have variable rate debt levels equal to or exceeding our swap positions during their term, the entire $450.0 million of these arrangements generally mitigate our interest rate risk through June 2012, with $150 million extending from June 2012 through June 2014. Based on our current operations we believe our interest rate swap agreements adequately mitigate our interest rate risk associated with our variable rate debt.

We have designated $425.0 million of our interest rate swap agreements as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. The effect that these swaps have on our condensed consolidated financial statements, as well as the effect that is expected over the upcoming 12 months is summarized in the charts below. However, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings.

As of March 31, 2011, $275.0 million of the agreements reprice prospectively approximately every 90 days and the remaining $175.0 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 5.19%, and receive interest payments based on the three-month and one-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense.

Contingent Credit Features

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

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

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

- In the event that 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 March 31, 2011, we are not a party to any agreements that would be subject to these provisions other than our credit agreement.

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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 March 31, 2011, we had $99.4 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 March 31, 2011, if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of March 31, 2011, 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 $95.5 million.

As of March 31, 2011, our interest rate swaps were in a net liability position of approximately $22.8 million, of which, the entire amount is subject to credit-risk related contingent features. If we were to have a default of any of our covenants to our Credit Agreement, that occurs and is continuing, the counterparties to our swap instruments have the right to request that we net settle the instrument in the form of cash.

Collateral

As of March 31, 2011, we had a contingent letter of credit facility for up to $10.0 million, on which we have no letters of credit issued. DCP Midstream, LLC had issued and outstanding parental guarantees totaling $85 million in favor of certain counterparties to our commodity derivative instruments. This contingent letter of credit facility and the parental guarantees reduce the amount of cash we may be required to post as collateral. As of March 31, 2011, 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:

	March 31, 2011	December 31, 2010
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (0.2)	$ (0.3)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(23.1)	(27.4)
Total AOCI	$ (23.3)	$ (27.7)

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

Balance Sheet Line Item	March 31, 2011	December 31, 2010	Balance Sheet Line Item	March 31, 2011	December 31, 2010
	(Millions)			(Millions)	
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments:**		
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (16.1)	$ (12.2)
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term	(5.6)	(5.4)
	$	$		$ (21.7)	$ (17.6)
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments current	$ 0.9	$ 1.9	Unrealized losses on derivative instruments current	$ (37.3)	$ (26.0)
Unrealized gains on derivative instruments long-term	3.1	1.4	Unrealized losses on derivative instruments long-term	(63.4)	(40.4)
	$ 4.0	$ 3.3		$ (100.7)	$ (66.4)
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (0.9)	$ (4.8)
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term	(0.2)	(4.5)
	$	$		$ (1.1)	$ (9.3)

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.

	Loss Recognized in AOCI on Derivatives Effective Portion		Loss Reclassified From AOCI to Earnings Effective Portion		Gain (Loss) Recognized in Income on Derivatives Ineffective Portion and Amount Excluded From Effectiveness Testing		Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	Three Months Ended March 31,						
	2011	2010	2011	2010	2011	2010	
	(Millions)		(Millions)		(Millions)		(Millions)
Interest rate derivatives	$ (0.9)	$ (7.6)	$ (5.2)	$ (5.6)(a)	$	$ (a)(c)	$ (19.0)
Commodity derivatives	$	$	$ (0.1)	$ (0.4)(b)	$	$ (b)(c)	$ (0.2)

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) Included in sales of natural gas, propane, NGLs and condensate in our condensed consolidated statements of operations.
(c) For the three months ended March 31, 2011 and 2010, 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.

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

Commodity Derivatives: Statements of Operations Line Item	Three Months Ended March 31, 2011	2010
Third party:	(Millions)	
Realized	$ (6.0)	$ (2.1)
Unrealized	(32.9)	8.1
(Losses) gains from commodity derivative activity, net	$ (38.9)	$ 6.0
Affiliates:		
Realized	$ (0.6)	$ (0.1)
Unrealized	(0.7)	0.1
Losses from commodity derivative activity, net affiliates	$ (1.3)	$

Interest Rate Derivatives: Statements of Operations Line Item	Three Months Ended March 31, 2011	2010
Third party:	(Millions)	
Realized	$ (1.0)	$
Unrealized	$ 1.6	$
Interest gain	$ 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.

	March 31, 2011		
Year of Expiration	Crude Oil Net Long (Short) Position (Bbls)	Natural Gas Net Long (Short) Position (MMBtu)	Natural Gas Liquids Net Long (Short) Position (Bbls)
2011	(442,505)	(1,165,000)	(716,303)
2012	(1,038,762)	(366,000)	
2013	(948,365)	(365,000)	
2014	(547,500)	(365,000)	
2015	(365,000)		
2016	(183,000)		

	March 31, 2010		
Year of Expiration	Crude Oil	Natural Gas	Natural Gas Liquids

	Net Long (Short) Position (Bbls)	Net Long (Short) Position (MMBtu)	Net Long (Short) Position (Bbls)
2010	(732,875)	(1,840,000)	(440,000)
2011	(949,000)	(1,496,500)	
2012	(777,750)	(1,500,600)	
2013	(748,250)	(730,000)	
2014	(365,000)		

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We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of March 31, 2011, we have swaps with a notional value between $25.0 million and $80.0 million, which, in aggregate, exchange up to $450.0 million of our floating rate obligation to a fixed rate obligation through June 2012, with $150.0 million extending from June 2012 through June 2014.

11. Partnership Equity and Distributions

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

In March 2011, we issued 3,596,636 common limited partner units at $40.55 per unit. We received proceeds of $139.7 million, net of offering costs.

In February 2011, we issued 8,399 common limited partner units, from our long-term incentive plan, or LTIP, to employees as compensation for their service during 2010, 2009 and 2008.

In November 2010, we issued 2,875,000 common limited partner units at $34.96 per unit. We received proceeds of $96.2 million, net of offering costs.

In September 2010, we issued 5,200 common limited partner units, from our LTIP to non-employee directors as compensation for their service during 2010.

In August 2010, we issued 2,990,000 common limited partner units at $32.57 per unit. We received proceeds of $93.1 million, net of offering costs.

On May 26, 2010, we filed a universal shelf registration statement on Form S-3 with the SEC with a maximum aggregate offering price of $1.5 billion, to replace an existing shelf registration statement. The universal shelf registration statement will allow us to register and issue additional partnership units and debt securities.

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 March 31, 2011. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest.

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

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

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

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

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

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

The following table presents our cash distributions paid in 2011 and 2010:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
February 14, 2011	$ 0.6175	$ 30.0
November 12, 2010	$ 0.610	$ 27.4
August 13, 2010	$ 0.610	$ 25.3
May 14, 2010	$ 0.600	$ 24.6
February 12, 2010	$ 0.600	$ 24.6

12. Equity-Based Compensation

On November 28, 2005, the board of directors of our General Partner adopted a long-term incentive plan, or LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 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 delivered pursuant to awards under the 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. The LTIP is administered by the compensation committee of the General Partner s board of directors. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to directors in conjunction with our initial public offering, which are subject to graded vesting provisions.

Prior to February 18, 2011, substantially all equity-based awards were accounted for as liability awards. Effective February 18, 2011, the Modification Date, we have the intent and ability to settle certain awards within our control in units and therefore modified the accounting for these awards. We now classify them as equity awards based on their re-measured fair value. The fair value was determined based on the closing price of our common units on the Modification Date. Such modification resulted in a reclassification of $1.9 million from share-based compensation liability to additional paid-in capital on the Modification Date. Compensation expense on unvested equity awards as of the Modification Date will be recognized ratably over each remaining vesting period.

We will continue to account for other awards, which are subject to settlement in cash as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period for all awards outstanding until the units are vested. The fair value of all liability awards is determined based on the closing price of our common units at each measurement date.

The reclassification of the affected awards does not impact our accounting for dividend equivalent rights as these instruments will continue to be settled in cash and therefore retain their share-based compensation liability classification.

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13. Income Taxes

We are structured as a master limited partnership, which is a pass-through entity for federal income tax purposes. On December 30, 2010, we acquired all of the interests in Marysville Hydrocarbons Holdings, LLC, an entity that owns a taxable C-Corporation consolidated return group. We estimated $35.0 million of deferred tax liabilities resulting from built-in tax gains recognized in the transaction and recorded this in our preliminary purchase price allocation as of December 31, 2010.

On January 4, 2011, we merged two wholly-owned subsidiaries of Marysville Hydrocarbons Holding, LLC and converted the combined entity s organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggers the deferred tax liabilities resulting from built-in tax gains to become currently payable. Accordingly, the estimated $35.0 million of deferred tax liabilities at December 31, 2010 have been reflected as a current income tax payable in our condensed consolidated balance sheet as of March 31, 2011.

14. Commitments and Contingent Liabilities

Litigation We are a party to various legal proceedings, as well as administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our condensed consolidated results of operations, financial position, or cash flows. See Note 17 in Item 8 of our 2010 Form 10-K for additional details.

Insurance We renewed our insurance policies in May, June and July 2010 for the 2010-2011 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 2010-2011 insurance year compared with the 2009-2010 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 2010-2011 insurance year covers onshore named windstorm property and business interruption insurance and onshore and offshore non-windstorm property and business interruption insurance. The availability of offshore named windstorm property and business interruption insurance has been significantly reduced over the past two 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. Consequently, as with the 2009-2010 insurance year, Discovery elected to not purchase offshore named windstorm property and business interruption insurance coverage for the 2010-2011 insurance year. There is a possibility that this situation could continue to occur periodically.

Environmental 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 which was included in Title V reports to the State. The TCEQ has requested detailed follow-up from us and an action plan to address this matter. At this time formal enforcement has not been initiated, although it is not possible to predict what action the TCEQ may take or the cost to address this matter. We do not believe the ultimate resolution of this matter will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Indemnification DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors. See the Indemnification section of Note 5 in Item 8 of our 2010 Form 10-K for additional details.

15. Business Segments

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

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Natural Gas Services Our Natural Gas Services segment provides services that include gathering, compressing, treating, processing, fractionating, transporting and storing natural gas. The segment consists of our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our Michigan system, our 33.33% interest in the Southeast Texas system, our 50.1% interest in the East Texas system, (acquired in January 2011) our 75% interest in the Colorado system and our 40% limited liability company interest in Discovery.

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 (Atlantic, acquired in July 2010), one pipeline terminal and access to several open-access pipeline terminals.

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 (acquired in January 2010) and Black Lake (acquired the remaining 55% interest in July 2010 to bring our total interest to 100%) interstate NGL pipelines, the NGL storage facility in Michigan (Marysville, acquired in December 2010) and the DJ Basin NGL Fractionators in Colorado (acquired in March 2011).

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

The following tables set forth our segment information:

Three Months Ended March 31, 2011

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Eliminations	Total
			(Millions)			
Total operating revenue	$ 164.5	$ 247.8	$ 15.0	$	$ (2.2)	$ 425.1
Total purchases	(146.5)	(226.0)	(4.7)		2.2	(375.0)
Gross margin (a)	$ 18.0	$ 21.8	$ 10.3	$	$	$ 50.1
Operating and maintenance expense	(16.5)	(3.6)	(4.0)			(24.1)
Depreciation and amortization expense	(17.5)	(0.7)	(1.7)			(19.9)
General and administrative expense				(9.0)		(9.0)
Other income			0.1			0.1
Earnings from unconsolidated affiliates	8.6					8.6
Interest expense				(8.0)		(8.0)
Income tax expense (b)				(0.2)		(0.2)
Net (loss) income	(7.4)	17.5	4.7	(17.2)		(2.4)
Net income attributable to noncontrolling interests	(3.5)					(3.5)
Net (loss) income attributable to partners	$ (10.9)	$ 17.5	$ 4.7	$ (17.2)	$	$ (5.9)
Non-cash derivative mark-to-market (c)	$ (33.4)	$ (0.3)	$	$ (0.2)	$	$ (33.9)
Capital expenditures	$ 8.8	$ 0.6	$ 4.3	$	$	$ 13.7
Acquisition expenditures	$ 121.8	$	$ 29.6	$	$	$ 151.4

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Three Months Ended March 31, 2010

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics (Millions)	Other	Total
Total operating revenue	$ 218.1	$ 180.8	$ 4.8	$	$ 403.7
Total purchases	(164.3)	(167.1)	(1.4)		(332.8)
Gross margin (a)	$ 53.8	$ 13.7	$ 3.4	$	$ 70.9
Operating and maintenance expense	(16.2)	(2.6)	(0.2)		(19.0)
Depreciation and amortization expense	(17.0)	(0.3)	(0.5)		(17.8)
General and administrative expense				(8.6)	(8.6)
Earnings from unconsolidated affiliates	13.9		0.5		14.4
Interest expense				(7.2)	(7.2)
Income tax expense (b)				(0.3)	(0.3)
Net income (loss)	34.5	10.8	3.2	(16.1)	32.4
Net income attributable to noncontrolling interests	(0.1)				(0.1)
Net income (loss) attributable to partners	$ 34.4	$ 10.8	$ 3.2	$ (16.1)	$ 32.3
Non-cash derivative mark-to-market (c)	$ 8.4	$ (0.6)	$	$	$ 7.8
Capital expenditures	$ 12.1	$	$ 0.1	$	$ 12.2
Acquisition expenditures	$	$	$ 22.0	$	$ 22.0
Investments in unconsolidated affiliates	$ 0.7	$	$	$	$ 0.7

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	March 31, 2011	December 31, 2010
	(Millions)	
Segment long-term assets:		
Natural Gas Services (e)	$ 1,250.7	$ 1,253.7
Wholesale Propane Logistics	101.4	101.7
NGL Logistics	253.0	221.7
Other (d)	6.3	4.1
Total long-term assets	1,611.4	1,581.2
Current assets	199.9	232.0
Total assets	$ 1,811.3	$ 1,813.2

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

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

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

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

(e) The segment information for the three months ended March 31, 2011 and as of December 31, 2010 includes the results of Southeast Texas as transfers of net assets between entities under common control 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.

16. Supplemental Cash Flow Information

	Three Months Ended March 31, 2011	2010
	(Millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$ 1.2	$ 1.6
Cash paid for income taxes, net of income tax refunds	$	$
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable	$ 4.1	$ 3.9
Other non-cash additions of property, plant and equipment	$ 10.9	$ 0.2
Acquisition related contingent consideration	$	$ 1.0
Accounts payable related to equity issuance costs	$ 0.1	$
Non-cash change in parent advances	$ 1.7	$
Non-cash distributions to DCP Midstream, LLC	$ 2.6	$

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17. 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 May 26, 2010, 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.

	Condensed Consolidating Balance Sheets March 31, 2011				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$	$ 1.5	$ 4.8	$ (1.3)	$ 5.0
Accounts receivable			150.5		150.5
Inventories			42.1		42.1
Other			2.3		2.3
Total current assets		1.5	199.7	(1.3)	199.9
Property, plant and equipment, net			1,120.6		1,120.6
Goodwill and intangible assets, net			264.6		264.6
Advances receivable consolidated subsidiaries	443.1	553.1		(996.2)	
Investments in consolidated subsidiaries	146.9	289.3		(436.2)	
Investments in unconsolidated affiliates			216.0		216.0
Other long-term assets		2.2	8.0		10.2
Total assets	$ 590.0	$ 846.1	$ 1,808.9	$ (1,433.7)	$ 1,811.3
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ 0.3	$ 17.6	$ 223.2	$ (1.3)	$ 239.8
Advances payable consolidated subsidiaries			996.2	(996.2)	
Long-term debt		675.8			675.8
Other long-term liabilities		5.8	79.1		84.9
Total liabilities	0.3	699.2	1,298.5	(997.5)	1,000.5
Commitments and contingent liabilities					
Equity:					
Partners equity					
Net equity	589.7	170.0	289.5	(436.2)	613.0
Accumulated other comprehensive loss		(23.1)	(0.2)		(23.3)
Total partners equity	589.7	146.9	289.3	(436.2)	589.7
Noncontrolling interests			221.1		221.1
Total equity	589.7	146.9	510.4	(436.2)	810.8
Total liabilities and equity	$ 590.0	$ 846.1	$ 1,808.9	$ (1,433.7)	$ 1,811.3

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Condensed Consolidating Balance Sheets
December 31, 2010 (a)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$	$ 1.5	$ 6.7	$ (1.5)	$ 6.7
Accounts receivable			151.0		151.0
Inventories			64.1		64.1
Other			10.2		10.2
Total current assets		1.5	232.0	(1.5)	232.0
Property, plant and equipment, net			1,097.1		1,097.1
Goodwill and intangible assets, net			258.6		258.6
Advances receivable consolidated subsidiaries	333.4	534.7		(868.1)	
Investments in consolidated subsidiaries	297.5	436.2		(733.7)	
Investments in unconsolidated affiliates			216.9		216.9
Other long-term assets		2.3	6.3		8.6
Total assets	$ 630.9	$ 974.7	$ 1,810.9	$ (1,603.3)	$ 1,813.2
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ 0.2	$ 19.5	$ 193.0	$ (1.5)	$ 211.2
Advances payable consolidated subsidiaries			868.1	(868.1)	
Long-term debt		647.8			647.8
Other long-term liabilities		9.9	93.5		103.4
Total liabilities	0.2	677.2	1,154.6	(869.6)	962.4
Commitments and contingent liabilities					
Equity:					
Partners equity					
Predecessor equity			112.6		112.6
Net equity	630.7	324.9	323.9	(733.7)	545.8
Accumulated other comprehensive loss		(27.4)	(0.3)		(27.7)
Total partners equity	630.7	297.5	436.2	(733.7)	630.7
Noncontrolling interests			220.1		220.1
Total equity	630.7	297.5	656.3	(733.7)	850.8
Total liabilities and equity	$ 630.9	$ 974.7	$ 1,810.9	$ (1,603.3)	$ 1,813.2

(a) The financial information as of December 31, 2010 includes the results of Southeast Texas as transfers of net assets between entities under common control 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.

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	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	Condensed Consolidating Statements of Operations Three Months Ended March 31, 2011				
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$	$	$ 429.7	$	$ 429.7
Transportation, processing and other			35.6		35.6
Losses from commodity derivative activity, net			(40.2)		(40.2)
Total operating revenues			425.1		425.1
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs			(375.0)		(375.0)
Operating and maintenance expense			(24.1)		(24.1)
Depreciation and amortization expense			(19.9)		(19.9)
General and administrative expense			(9.0)		(9.0)
Other income			0.1		0.1
Total operating costs and expenses			(427.9)		(427.9)
Operating (loss) income			(2.8)		(2.8)
Interest expense, net		(8.0)			(8.0)
(Losses) income from consolidated subsidiaries	(5.9)	2.1		3.8	
Earnings from unconsolidated affiliates			8.6		8.6
(Losses) income before income taxes	(5.9)	(5.9)	5.8	3.8	(2.2)
Income tax expense			(0.2)		(0.2)
Net (loss) income	(5.9)	(5.9)	5.6	3.8	(2.4)
Net income attributable to noncontrolling interests			(3.5)		(3.5)
Net (loss) income attributable to partners	$ (5.9)	$ (5.9)	$ 2.1	$ 3.8	$ (5.9)

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	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	Condensed Consolidating Statements of Operations Three Months Ended March 31, 2010 (a)				
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$	$	$ 370.4	$	$ 370.4
Transportation, processing and other			27.3		27.3
Gains from commodity derivative activity, net			6.0		6.0
Total operating revenues			403.7		403.7
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs			(332.8)		(332.8)
Operating and maintenance expense			(19.0)		(19.0)
Depreciation and amortization expense			(17.8)		(17.8)
General and administrative expense			(8.6)		(8.6)
Total operating costs and expenses			(378.2)		(378.2)
Operating income			25.5		25.5
Interest expense, net		(7.1)	(0.1)		(7.2)
Earnings from consolidated subsidiaries	32.3	39.4		(71.7)	
Earnings from unconsolidated affiliates			14.4		14.4
Income tax expense			(0.3)		(0.3)
Net income	32.3	32.3	39.5	(71.7)	32.4
Net income attributable to noncontrolling interests			(0.1)		(0.1)
Net income attributable to partners	$ 32.3	$ 32.3	$ 39.4	$ (71.7)	$ 32.3

(a) The financial information as of December 31, 2010 includes the results of Southeast Texas as transfers of net assets between entities under common control 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.

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Condensed Consolidating Statements of Cash Flows
Three Months Ended March 31, 2011

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries (Millions)	Consolidating Adjustments	Consolidated
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ (109.6)	$ (27.9)	$ 201.3	$ 0.2	$ 64.0
INVESTING ACTIVITIES:					
Capital expenditures			(13.7)		(13.7)
Acquisitions, net of cash acquired			(151.4)		(151.4)
Investments in unconsolidated affiliates			(0.1)		(0.1)
Proceeds from sale of assets			0.2		0.2
Net cash used in investing activities			(165.0)		(165.0)
FINANCING ACTIVITIES:					
Proceeds from debt		547.0			547.0
Payments of debt		(519.0)			(519.0)
Payment of deferred financing costs		(0.1)			(0.1)
Proceeds from issuance of common units, net of offering costs	139.7				139.7
Excess purchase price over acquired assets			(35.7)		(35.7)
Distributions to unitholders and general partner	(30.1)				(30.1)
Distributions to noncontrolling interests			(5.4)		(5.4)
Contributions from noncontrolling interests			2.9		2.9
Net cash provided by (used in) financing activities	109.6	27.9	(38.2)		99.3
Net change in cash and cash equivalents			(1.9)	0.2	(1.7)
Cash and cash equivalents, beginning of period		1.5	6.7	(1.5)	6.7
Cash and cash equivalents, end of period	$	$ 1.5	$ 4.8	$ (1.3)	$ 5.0

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Condensed Consolidating Statements of Cash Flows

	Three Months Ended March 31, 2010 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash provided by (used in) operating activities	$ 24.6	$ (12.0)	$ 42.0	$ (0.9)	$ 53.7
INVESTING ACTIVITIES:					
Capital expenditures			(12.2)		(12.2)
Acquisitions, net of cash acquired			(22.0)		(22.0)
Investments in unconsolidated affiliates			(0.7)		(0.7)
Proceeds from sale of assets			0.2		0.2
Proceeds from sales of available-for-sale securities		10.1			10.1
Net cash provided by (used in) investing activities		10.1	(34.7)		(24.6)
FINANCING ACTIVITIES:					
Proceeds from debt		116.6			116.6
Payments of debt		(114.6)			(114.6)
Distributions to unitholders and general partner	(24.6)				(24.6)
Distributions to noncontrolling interests			(3.7)		(3.7)
Contributions from noncontrolling interests			3.9		3.9
Net change in advances to predecessor from DCP Midstream LLC			(2.7)		(2.7)
Purchase of additional interest in a subsidiary			(3.5)		(3.5)
Net cash provided by (used in) financing activities	(24.6)	2.0	(6.0)		(28.6)
Net change in cash and cash equivalents		0.1	1.3	(0.9)	0.5
Cash and cash equivalents, beginning of period		1.6	1.3	(0.8)	2.1
Cash and cash equivalents, end of period	$	$ 1.7	$ 2.6	$ (1.7)	$ 2.6

(a) The financial information as of December 31, 2010 includes the results of Southeast Texas as transfers of net assets between entities under common control 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.

18. Subsequent Events

On April 25, 2011 the board of directors of the General Partner declared a quarterly distribution of $0.625 per unit, payable on May 13, 2011 to unitholders of record on May 6, 2011.

On April 18, 2011, we made an estimated federal tax payment of $29.3 million related to our acquisition of Marysville.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and the consolidated financial statements and notes thereto included in our 2010 Form 10-K.

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. Our operations are organized into three business segments: Natural Gas Services, Wholesale Propane Logistics and NGL Logistics.

Transfers of net assets between entities under common control 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 33.33% interest in Southeast Texas for all periods presented. We refer to our 33.33% interest in Southeast Texas, prior to our acquisition from DCP Midstream, LLC in January 2011, 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 of DCP Midstream, LLC s basis in the net assets is recognized as a reduction 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. Specifically, the terms of the joint venture agreement provide that distributions and earnings to us for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions and earnings related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Midstream, LLC s respective ownership interests in Southeast Texas. These terms of the agreement are not reflected in the historical financial statements.

Crude oil and NGL prices have generally remained at favorable levels, although natural gas prices have remained relatively low. Overall drilling and rig counts continue to improve. Drilling activity levels vary by geographic area, but in general drilling remains robust in areas with a high liquids content. In other areas, drilling remains depressed. In addition, advances in technology, such as horizontal drilling and fractionation in shale plays, have led to certain geographic areas becoming increasingly accessible. Gas prices currently remain modest due to increased supply relative to demand. Our long-term view is that commodity prices will be at levels that we believe will support sustained or increasing levels of natural gas drilling.

On January 1, 2011, we acquired a 33.33% interest in Southeast Texas from DCP Midstream, LLC for $150.0 million, in a transaction among entities under common control. The Southeast Texas system is a fully integrated midstream business which includes 675 miles of natural gas pipelines, three natural gas processing plants totaling 380 MMcf/d of processing capacity, natural gas storage assets with 9 Bcf of existing storage capacity, and NGL market deliveries direct to Exxon Mobil and to Mont Belvieu via our Black Lake NGL pipeline. The transaction is consistent with our growth strategy and provides additional diversification of our asset portfolio, geography and resource exposure.

On March 24, 2011, we acquired two NGL fractionation facilities, or DJ Basin NGL Fractionators, for $30.0 million. The DJ Basin NGL Fractionators which provide fee-based margins on long-term contracts are collocated with and operated by DCP Midstream, LLC.

Through the growth opportunities executed, we increased our business diversity, geographic and resource exposure, and our fee-based margins. Our integration efforts related to our acquisitions are progressing according to plan. The Wattenberg capital expansion project is expected to be online during the second quarter. We raised $139.7 million in capital through the successful execution of a public equity offering in March in order to finance a portion of our growth opportunities.

Financial results for the first quarter were in line with our previously provided 2011 forecast. We raised our distribution for the first quarter, resulting in a 4% increase in our quarterly distribution rate over the rate paid in the first quarter of 2010. The distribution reflects our business results as well as our recent execution on growth opportunities.

General Trends and Outlook

In 2011, 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 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, and 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 $10.0 million and $15.0 million, and expenditures for expansion capital of between $35.0 million and $50.0 million in 2011, including $10.0 million for the expansion of storage capacity at our Southeast Texas system. The board of directors may approve additional growth capital during the year, at their discretion. This capital does not include any acquisitions or additional investment opportunities that may be identified throughout the course of the year and approved by our management and our board of directors.

In 2011, we expect to continue to pursue a multi-faceted growth strategy, which may include executing on organic opportunities around our footprint, third party acquisition, and investment opportunities with our general partner in order to grow our distributable cash flows.

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 in our 2010 Form 10-K.

Recent Events

On April 25, 2011, the board of directors of the General Partner declared a quarterly distribution of $0.625 per unit, payable on May 13, 2011 to unitholders of record on May 6, 2011.

In March 2011, we issued 3,596,636 common limited partner units at $40.55 per unit. We received proceeds of $139.7 million, net of offering costs.

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 GAAP.

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

Reconciliation of Non-GAAP Measures	Three Months Ended March 31, 2011	2010
	(Millions)	
Reconciliation of net income attributable to partners to gross margin:		
Net (loss) income attributable to partners	$ (5.9)	$ 32.3
Interest expense	8.0	7.2
Income tax expense	0.2	0.3
Operating and maintenance expense	24.1	19.0
Depreciation and amortization expense	19.9	17.8
General and administrative expense	9.0	8.6
Other income	(0.1)	
Earnings from unconsolidated affiliates	(8.6)	(14.4)
Net income attributable to noncontrolling interests	3.5	0.1
Gross margin	$ 50.1	$ 70.9
Non-cash commodity derivative mark-to-market (a)	$ (33.7)	$ 7.8
Reconciliation of segment net income attributable to partners to segment gross margin:		
Natural Gas Services segment:		
Segment net (loss) income attributable to partners	$ (10.9)	$ 34.4
Operating and maintenance expense	16.5	16.2
Depreciation and amortization expense	17.5	17.0
Earnings from unconsolidated affiliates	(8.6)	(13.9)
Net income attributable to noncontrolling interests	3.5	0.1
Segment gross margin	$ 18.0	$ 53.8
Non-cash commodity derivative mark-to-market (a)	$ (33.4)	$ 8.4
Wholesale Propane Logistics segment:		
Segment net income attributable to partners	$ 17.5	$ 10.8
Operating and maintenance expense	3.6	2.6
Depreciation and amortization expense	0.7	0.3
Segment gross margin	$ 21.8	$ 13.7
Non-cash commodity derivative mark-to-market (a)	$ (0.3)	$ (0.6)
NGL Logistics segment:		
Segment net income attributable to partners	$ 4.7	$ 3.2
Operating and maintenance expense	4.0	0.2
Depreciation and amortization expense	1.7	0.5
Other income	(0.1)	
Earnings from unconsolidated affiliates		(0.5)
Segment gross margin	$ 10.3	$ 3.4

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

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Operating and Maintenance and General and Administrative Expense Operating and maintenance expenses are costs associated with the operation of a specific asset and are primarily comprised of direct labor, ad valorem taxes, repairs and maintenance, lease expenses, utilities and contract services. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee under the Omnibus Agreement for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. On January 1, 2011, we extended the omnibus agreement through December 31, 2011 for $10.2 million.

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

- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures;
- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Our adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate 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.

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 capacity or revenues. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing Distributable Cash Flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices. Distributable Cash Flow is used as a supplemental liquidity 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.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2010 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three months ended March 31, 2011 are the same as those described in our 2010 Form 10-K.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2011 and 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended March 31,		Variance Three Months 2011 vs. 2010	
	2011 (b) (c) (d)	2010 (b) (c) (d)	Increase (Decrease)	Percent
	(Millions, except as indicated)			
Operating revenues (h):				
Natural Gas Services (e)	$ 164.5	$ 218.1	$ (53.6)	(25)%
Wholesale Propane Logistics	247.8	180.8	67.0	37%
NGL Logistics	15.0	4.8	10.2	213%
Intra-segment Eliminations	(2.2)		2.2	100%
Total operating revenues	425.1	403.7	21.4	5%
Gross margin (f):				
Natural Gas Services	18.0	53.8	(35.8)	(67)%
Wholesale Propane Logistics	21.8	13.7	8.1	59%
NGL Logistics	10.3	3.4	6.9	203%
Total gross margin	50.1	70.9	(20.8)	(29)%
Operating and maintenance expense	(24.1)	(19.0)	5.1	27%
Depreciation and amortization expense	(19.9)	(17.8)	2.1	12%
General and administrative expense	(9.0)	(8.6)	0.4	5%
Other income	0.1		0.1	100%
Earnings from unconsolidated affiliates (a) (g)	8.6	14.4	(5.8)	(40)%
Interest income				%
Interest expense	(8.0)	(7.2)	0.8	11%
Income tax expense	(0.2)	(0.3)	(0.1)	(33)%
Net income attributable to noncontrolling interests	(3.5)	(0.1)	3.4	*
Net income (loss) attributable to partners	$ (5.9)	$ 32.3	$ (38.2)	(118)%
Other data:				
Non-cash commodity derivative mark-to-market	$ (33.7)	$ 7.8	$ (41.5)	*
Natural gas throughput (MMcf/d) (g)	1,274	1,269	5	%
NGL gross production (Bbls/d) (g)	40,674	40,225	449	1%
Propane sales volume (Bbls/d)	40,038	33,356	6,682	20%
NGL pipelines throughput (Bbls/d) (g)	45,713	39,911	5,802	15%

* Percentage change is not meaningful.

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(a) On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million, in a transaction among entities under common control. Transfers of net assets between entities under common control 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 33.33% interest in Southeast Texas for the three months ended March 31, 2010.

(b) Includes the results of Atlantic Energy, since July 30, 2010, the date of acquisition, in our Wholesale Propane Logistics segment.

(c) Includes the results of our Wattenberg pipeline, Black Lake pipeline, Marysville NGL storage facility and DJ Basin NGL Fractionators since the dates of acquisition of January 28, 2010, July 30, 2010, December 30, 2010 and March 24, 2011, respectively, in our NGL Logistics Segment.

(d) We utilize commodity derivative instruments to provide stability to distributable cash flows for our proportionate ownership in East Texas as well as all other natural gas services assets, the portion of East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 49.9% of East Texas unhedged.

(e) Includes the effect of the acquisition of the NGL Hedge, contributed by DCP Midstream, LLC in April 2009. The NGL Hedge is a fixed price natural gas liquids derivative by NGL component, which commenced in April 2009 and expired in March 2010.

(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 proportionate share of the throughput volumes and NGL production of Collbran, Jackson Pipeline Company, or Jackson, Southeast Texas, East Texas, and Discovery and our proportionate earnings of 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.

For periods prior to July 30, 2010, includes our 50% share of the throughput volumes and earnings for Black Lake. Black Lake s earnings included the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

(h) Operating revenues include the impact of commodity derivative activity.

Three Months Ended March 31, 2011 vs. Three Months Ended March 31, 2010

Total Operating Revenues Total operating revenues increased in 2011 compared to 2010 primarily as a result of the following:

- $67.4 million increase primarily attributable to our acquisition of Atlantic Energy, as well as higher propane prices for our Wholesale Propane Logistics segment; and

- $8.3 million increase in transportation, processing and other revenue, which represents our fee-based revenues, primarily as a result of our acquisitions of the Marysville NGL storage facility and an additional 50% interest in Black Lake.

These increases were partially offset by:

- $46.2 million decrease related to commodity derivative activity. This includes unrealized losses in 2011 compared to unrealized gains in 2010, for a decrease of $41.8 million due to movements in forward prices of commodities, and an increase in realized cash settlement losses of $4.4 million; and

- $9.3 million decrease attributable to decreases in natural gas prices and the impact of changes in contract mix, partially offset by increases in crude oil and NGL prices.

Gross Margin Gross margin decreased in 2011 compared to 2010, primarily as a result of the following:

- $35.8 million decrease for our Natural Gas Services segment, primarily related to commodity derivative activity as explained in the Operating Revenues section above. These decreases were partially offset by higher crude oil and NGL prices. The 2010 results reflect the impact of plant shutdowns and producer wellhead freeze offs as a result of near record cold weather at East Texas and North Lousiana.

This decrease was partially offset by:

- $8.1 million increase for our Wholesale Propane Logistics segment primarily as a result of our acquisition of Atlantic Energy and higher per unit margins; and

- $6.9 million increase for our NGL Logistics segment primarily as a result of our acquisitions of the Marysville NGL storage facility and an additional 50% interest in Black Lake. The 2010 results include a market opportunity at Seabreeze.

Operating and Maintenance Expense Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, Atlantic Energy, an additional 50% interest in Black Lake, and the Wattenberg pipeline.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, Atlantic Energy and an additional 50% interest in Black Lake, as well as organic expansion capital spending.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates decreased in 2011 compared to 2010 reflecting the impact of the moratorium in the Gulf and timing of expenditures at Discovery. The 2010 results for Southeast Texas include the impact of Hurricane Ike business interruption insurance recoveries.

Net income attributable to noncontrolling interests Net income attributable to noncontrolling interests increased in 2010 compared to 2011. The 2010 results include the impact of plant shutdowns and producer wellhead freeze offs as a result of near record cold weather at East Texas.

Results of Operations Natural Gas Services Segment

This segment consists of our Northern Louisiana system, the Southern Oklahoma system, a 40% limited liability company interest in Discovery, our 33.33% equity interest in the Southeast Texas system, our Colorado and Wyoming systems, our East Texas system, and our Michigan system.

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	Three Months Ended March 31, 2011 (a)	Three Months Ended March 31, 2010 (a)	Variance Three Months 2011 vs. 2010 Increase (Decrease)	Variance Three Months 2011 vs. 2010 Percent
	(Millions, except as indicated)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 178.7	$ 187.6	$ (8.9)	(5)%
Transportation, processing and other	25.2	24.3	0.9	4%
(Losses) gains from commodity derivative activity (c)	(39.4)	6.2	(45.6)	(735)%
Total operating revenues	164.5	218.1	(53.6)	(25)%
Purchases of natural gas and NGLs	(146.5)	(164.3)	(17.8)	(11)%
Segment gross margin (d)	18.0	53.8	(35.8)	(67)%
Operating and maintenance expense	(16.5)	(16.2)	0.3	2%
Depreciation and amortization expense	(17.5)	(17.0)	0.5	3%
Earnings from unconsolidated affiliates (b) (e)	8.6	13.9	(5.3)	(38)
Segment net (loss) income	(7.4)	34.5	(41.9)	(121)%
Segment net income attributable to noncontrolling interests	(3.5)	(0.1)	3.4	*
Segment net income attributable to partners	$ (10.9)	$ 34.4	$ (45.3)	(132)%
Other data:				
Non-cash commodity derivative mark-to-market	$ (33.4)	$ 8.4	$ (41.8)	*
Natural gas throughput (MMcf/d) (e)	1,274	1,269	5	%
NGL gross production (Bbls/d) (e)	40,674	40,225	449	1%

* 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, the portion of East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 49.9% of East Texas unhedged.

(b) On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million, in a transaction among entities under common control. Transfers of net assets between entities under common control 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 Southeast Texas for the three months ended March 31, 2010.

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

(d) 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.

(e) Includes our proportionate share of the throughput volumes and NGL production of Collbran, Jackson, Southeast Texas, East Texas and Discovery and our proportionate share of the earnings of Discovery and Southeast Texas for each period presented. Earnings for Discovery include the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

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Three Months Ended March 31, 2011 vs. Three Months Ended March 31, 2010

Total Operating Revenues Total operating revenues decreased in 2011 compared to 2010 primarily as a result of the following:

- $45.6 million decrease related to commodity derivative activity. This includes unrealized losses in 2011 compared to unrealized gains in 2010, for a decrease of $42.1 million due to movements in forward prices of commodities, and an increase in realized cash settlement losses of $3.5 million; and

- $10.8 million decrease attributable to reduced volumes on our Pelico system and changes in contract mix.

These decreases were partially offset by:

- $2.4 million increase attributable to increased crude oil and NGL prices and changes in contracts, partially offset by decreases in natural gas prices.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased in 2011 compared to 2010, primarily as a result of decreased natural gas prices and reduced volumes on our Pelico system, partially offset by increases in crude oil and NGL prices which impacts both purchases and sales.

Segment Gross Margin Segment gross margin decreased in 2011 compared to 2010, primarily as a result of the following:

- $45.6 million decrease related to commodity derivative activities as discussed in the Operating Revenues section above.

This decrease was partially offset by:

- $6.6 million increase from the 2010 plant shutdowns and producer wellhead freeze offs as a result of record cold weather at East Texas and North Louisiana; and

- $3.2 million increase as a result of higher crude oil and NGL prices.

Operating and Maintenance Expense Operating and maintenance expense was increased slightly in 2011 compared to 2010 as a result of organic expansion capital spending.

Depreciation and Amortization Expense Depreciation and amortization expense was relatively stable in 2011 compared to 2010.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery and 33.33% ownership of Southeast Texas, decreased in 2011 compared to 2010, due primarily to the impact of the moratorium in the Gulf and timing of expenditures at Discovery. The 2010 results for Southeast Texas include $1.5 million for business interruption insurance recoveries. Settlements related to our commodity derivatives in 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 2011 compared to 2010. The 2010 results include the impact of severe weather and operational challenges at East Texas initiated by weather.

Natural Gas Throughput Natural gas transported, processed and/or treated was relatively stable in 2011 compared to 2010.

NGL Gross Production NGL production was relatively stable in 2011 compared to 2010.

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Results of Operations — Wholesale Propane Logistics Segment

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

	Three Months Ended March 31,		Variance Three Months 2011 vs. 2010	
	2011 (a)	2010	Increase (Decrease)	Percent
	(Millions, except as indicated)			
Operating revenues:				
Sales of propane	$ 248.4	$ 181.0	$ 67.4	37%
Other	0.2		0.2	100
Losses from commodity derivative activity	(0.8)	(0.2)	0.6	300%
Total operating revenues	247.8	180.8	67.0	37%
Purchases of propane	(226.0)	(167.1)	58.9	35%
Segment gross margin (b)	21.8	13.7	8.1	59%
Operating and maintenance expense	(3.6)	(2.6)	1.0	38%
Depreciation and amortization expense	(0.7)	(0.3)	0.4	133%
Segment net income attributable to partners	$ 17.5	$ 10.8	$ 6.7	62%
Other data:				
Non-cash commodity derivative mark-to-market	$ (0.3)	$ (0.6)	$ 0.3	*
Propane sales volume (Bbls/d)	40,038	33,356	6,682	20%

* Percentage change is not meaningful.

(a) Includes the results of Atlantic Energy, since July 30, 2010, the date of acquisition.

(b) 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 March 31, 2011 vs. Three Months Ended March 31, 2010

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010, primarily as a result of the following:

- $40.5 million increase primarily attributable to our acquisition of Atlantic Energy; and
- $26.9 million increase attributable to higher propane prices, which impacts both purchases and sales.

These increases were partially offset by:

- $0.6 million decrease related to commodity derivative activity.

Purchases of Propane Purchases of propane increased in 2011 compared to 2010, due to higher propane prices, which impact both sales and purchases and of our acquisition of Atlantic Energy.

Segment Gross Margin Segment gross margin increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy and higher per unit margins.

Operating and Maintenance Expense Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy.

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Depreciation and Amortization Expense Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy.

Propane Sales Volume Propane sales volumes increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy.

Results of Operations NGL Logistics Segment

This segment includes our Seabreeze, Wilbreeze, Wattenberg and Black Lake transportation pipelines, our Marysville NGL storage facility and our DJ Basin NGL Fractionators:

	Three Months Ended March 31,		Variance Three Months 2011 vs. 2010	
	2011 (b) (d)	2010 (b)	Increase (Decrease)	Percent
Operating revenues:				
Sales of NGLs	$ 4.8	$ 1.8	$ 3.0	167%
Transportation, processing and other	10.2	3.0	7.2	240%
Total operating revenues	15.0	4.8	10.2	213%
Purchases of NGLs	(4.7)	(1.4)	3.3	236%
Segment gross margin (a)	10.3	3.4	6.9	203%
Operating and maintenance expense	(4.0)	(0.2)	3.8	1900%
Depreciation and amortization expense	(1.7)	(0.5)	1.2	240%
Other income	0.1		0.1	100%
Earnings from unconsolidated affiliates (c)		0.5	(0.5)	(100)%
Segment net income attributable to partners	$ 4.7	$ 3.2	$ 1.5	47%
Other data:				
NGL pipelines throughput (Bbls/d) (c)	45,713	39,911	5,802	15%

(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 Wattenberg pipeline and our Black Lake pipeline since the dates of acquisition of January 28, 2010 and July 30, 2010, respectively.
(c) For periods prior to July 30, 2010, includes our 50% share of the throughput volumes and earnings for Black Lake. Black Lake s earnings included the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.
(d) Includes the results of our Marysville NGL storage facility and our DJ Basin NGL Fractionators since the dates of acquisition of December 30, 2010 and March 24, 2011, respectively.

Three Months Ended March 31, 2011 vs. Three Months Ended March 31, 2010

Total Operating Revenues Total operating revenues increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility and an additional 50% interest in Black Lake. The 2010 results include a market opportunity at Seabreeze.

Segment Gross Margin Segment gross margin increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility and an additional 50% interest in Black Lake. The 2010 results include a market opportunity at Seabreeze.

Operating and Maintenance Expense Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, the Wattenberg pipeline and an additional 50% interest in Black Lake.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of Marysville NGL storage facility and an additional 50% interest in Black Lake.

NGL Pipelines Throughput NGL pipelines throughput increased in 2011 compared to 2010 as a result of our acquisition an additional 50% interest in Black Lake. The 2010 results include a market opportunity at Seabreeze.

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;
- issuance of additional partnership units;
- debt offerings;
- guarantees issued by DCP Midstream, LLC, which reduce the amount of collateral we may be required to post with certain counterparties to our commodity derivative instruments; and
- letters of credit.

We anticipate our more significant uses of resources to include:

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

We routinely evaluate opportunities for strategic investments or acquisitions. Future material investments or acquisitions may require that we obtain additional capital, 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.

In March 2011, we executed a public equity offering which generated net proceeds $139.7 million. The proceeds from the equity issuance were used primarily to fund our growth strategy, including acquisitions and organic expansion. The 2011 acquisitions include our purchase of a 33.33% interest in Southeast Texas for total cash consideration of $150.0 million and the DJ Basin NGL Fractionators for total cash consideration of $30.0 million. Our portion of expansion capital expenditures for the three months ended March 31, 2011 was $8.5 million.

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.

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 2010 Form 10-K and Item 3. Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report on Form 10-Q.

Our Credit Agreement consists of a revolving credit facility with capacity of $850.0 million, which matures on June 21, 2012. As of March 31, 2011, the outstanding balance on the revolving credit facility was $426.0 million resulting in unused revolver capacity of $423.5 million, of which approximately $365.0 million was available for general working capital purposes.

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 June 21, 2012 maturity date. As of May 6, 2011, we had approximately $393.0 million of unused capacity under the Credit Agreement.

On September 30, 2010, we issued $250.0 million of 3.25% Senior Notes due October 1, 2015. We received net proceeds, after deducting underwriting discounts and offering expenses, of $247.7 million, which we used to repay funds borrowed under the revolver portion of our Credit Facility.

In March 2011, we issued 3,596,636 common limited partner units at $40.55 per unit. We received proceeds of $139.7 million, net of offering costs.

The counterparties to each of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty s assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. As of May 6, 2011, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $95.0 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. As of May 6, 2011, we had a contingent issuance letter of credit facility for up to $10.0 million, on which we pay a fee of 0.50% per annum. As of May 6, 2011, we had no letters of credit issued on this facility; we will pay a net fee of 1.75% per annum on letters of credit issued on this facility. These parental guarantees and contingent issuance letter of credit facility reduce the amount of cash we may be required to post as collateral. This contingent issuance letter of credit facility was issued directly by a financial institution and does not reduce the available capacity under our credit facility. As of May 6, 2011, 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 restricted investments and other long-term assets.

We had a working capital deficit of $39.9 million as of March 31, 2011, compared to working capital of $20.8 million as of December 31, 2010. Included in these working capital amounts are net derivative working capital liabilities of $53.4 million and $41.1 million as of March 31, 2011 and December 31, 2010, 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 March 31, 2011, we had $5.0 million in cash and cash equivalents. Of this balance, as of March 31, 2011, $1.3 million was held by subsidiaries we do not wholly own, which we consolidate in our financial results. Other than the cash held by these subsidiaries, this cash balance was available for general corporate purposes. In 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, which has the potential to impact our cash collateral and reporting requirements for our trading activities and derivative positions depending on the final regulations adopted by the United States Commodity Futures Trading Commission and the U.S. Securities and Exchange Commission.

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

	Three Months Ended March 31,	
	2011	2010
	(Millions)	
Net cash provided by operating activities	$ 64.0	$ 53.7
Net cash used in investing activities	$ (165.0)	$ (24.6)
Net cash provided by (used in) financing activities	$ 99.3	$ (28.6)

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 paid approximately $6.6 million and $2.2 million for our net hedge cash settlements for the three months ended March 31, 2011 and March 31, 2010, respectively.

We received cash distributions from unconsolidated affiliates of $11.3 million and $12.5 million during the three months ended March 31, 2011 and 2010, respectively. Distributions exceeded earnings by $2.7 million and were $1.9 million less than earnings for the three months ended March 31, 2011 and 2010, respectively.

Net Cash Used in Investing Activities Net cash used in investing activities during the three months ended March 31, 2011 was comprised of: (1) acquisition expenditures of $29.6 million related to our acquisition of our DJ Basin NGL Fractionators; (2) acquisition expenditures of $114.3 million, representing the carrying value of the net assets acquired, related to our acquisition of Southeast Texas; (3) payment of $7.5 million to the seller of Michigan Pipeline & Processing, LLC in relation to our contingent payment agreement; (4) capital expenditures of $13.7 million (our portion of which was $10.2 million and the noncontrolling interest holders portion was $3.5 million); and (5) investments in unconsolidated affiliates of $0.1 million; partially offset by (6) proceeds from sales of assets of $0.2 million.

Net cash used in investing activities during the three months ended March 31, 2010 was comprised of: (1) acquisition expenditure of $22.0 million related to our acquisition of the Wattenberg NGL pipeline; (2) capital expenditures of $12.2 million (our portion of which was $6.8 million and the noncontrolling interest holders portion was $5.4 million); and (3) investments in Discovery of $0.7 million; partially offset by (4) net proceeds from sale of available-for-sale securities of $10.1 million; and (5) proceeds from sale of assets of $0.2 million.

Net Cash Provided by (Used in) Financing Activities Net cash provided by financing activities during the three months ended March 31, 2011 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $139.7 million; (2) contributions from noncontrolling interests of $2.9 million; and (3) net borrowing of debt of $28.0 million; partially offset by (4) distributions to our unitholders and general partner of $30.1 million; (5) distributions to noncontrolling interests of $5.4 million; (6) excess purchase price over the acquired net assets of Southeast Texas of $35.7 million; and (7) payment of deferred financing costs of $0.1 million.

Net cash used in financing activities during the three months ended March 31, 2010 was comprised of: (1) distributions to our unitholders and general partner of $24.6 million; (2) distributions to noncontrolling interests of $3.7 million; (3) purchase of additional interest in a subsidiary of $3.5 million; and (4) net change in advances to predecessor from DCP Midstream, LLC of $2.7 million; partially offset by (5) contributions from noncontrolling interests of $3.9 million; and (6) net borrowings of $2.0 million.

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During the three months ended March 31, 2011, total outstanding indebtedness under our $850.0 million Credit Agreement, which includes borrowings under our revolving credit facility, our term loan facility and letters of credit issued under the Credit Agreement, was not less than $425.5 million and did not exceed $591.1 million. The weighted-average indebtedness outstanding for the three months ended March 31, 2011 was $519.1 million.

We had unused revolver capacity, which is available commitments under the Credit Agreement, of $423.5 million as of March 31, 2011.

During the three months ended March 31, 2011, we had the following net movements on our revolving credit facility:

- $139.7 million repayment financed by the issue of 3,596,636 common units in March 2011; and
- $12.3 million net repayments; partially offset by
- $150.0 million borrowing to fund the acquisition of our 33.33% interest in Southeast Texas; and
- $30.0 million borrowing to fund the purchase of the DJ Basin NGL Fractionators.

During the three months ended March 31, 2010, we had the following net movements on our revolving credit facility:

- $22.0 million borrowing to fund the acquisition of the Wattenberg pipeline; and
- $10.0 million borrowing to fund repayment of our term loan facility; partially offset by
- $20.0 million net repayments.

During the three months ended March 31, 2010, we had a repayment of $10.0 million on our term loan facility and released $10.0 million of restricted investments which were required as collateral for the facility.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 11 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 capacity or revenues; and
- expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets in each case if such addition, improvement, acquisition or construction is made to increase our operating capacity or revenues.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $10.0 million and $15.0 million, and expenditures for expansion capital improvements of between $35.0 million and $50.0 million for the year ending December 31, 2011, including $10.0 million for the expansion to storage capacity at our Southeast Texas system. The board of directors may approve additional growth capital during the year, at their discretion.

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

	Three months ended March 31, 2011			Three Months Ended March 31, 2010		
	Maintenance Capital Expenditures	Expansion Capital Expenditures (Millions)	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures (Millions)	Total Consolidated Capital Expenditures
Our portion	$ 1.7	$ 8.5	$ 10.2	$ 3.0	$ 3.8	$ 6.8
Noncontrolling interest portion	1.2	2.3	3.5	3.6	1.8	5.4
Total	$ 2.9	$ 10.8	$ 13.7	$ 6.6	$ 5.6	$ 12.2

In addition, we invested cash in unconsolidated affiliates of $0.1 million and $0.7 million during the three months ended March 31, 2011 and March 31, 2010, to fund our share of capital expansion projects. Our expansion capital improvements forecast includes $10 million of expenditures, shown as investments in unconsolidated affiliates, for capital improvements related to our January 2011 Southeast Texas acquisition.

We intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, which could include 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 and the issuance of additional partnership units or 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 $30.1 million during the three months ended March 31, 2011, as compared to $24.6 million for the same period in 2010. 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 an $850.0 million revolving credit facility at March 31, 2011. The Credit Agreement matures on June 21, 2012. As of March 31, 2011, the outstanding balance on the revolving credit facility was $426.0 million resulting in unused revolver capacity of $423.5 million, of which approximately $365.0 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 March 31, 2011 and December 31, 2010, we had $0.5 million and $32.1 million, respectively, outstanding letters of credit issued under the Credit Agreement.

The term loan facility, which was repaid during the first quarter of 2010, was secured at all times by high-grade securities, in an amount equal to or greater than the outstanding principal amount of the term loan. Upon the repayment of term loan facility during the first quarter of 2010, the amount of our revolving credit facility increased by the amount repaid.

As of March 31, 2011, the weighted-average interest rate on our revolving credit facility was 0.73% per annum, excluding the impact of interest rate swaps.

Description of Debt Securities On September 30, 2010, we issued $250.0 million of our 3.25% Senior Notes due October 1, 2015. We received net proceeds of $247.7 million, net of underwriters fees, related expense and unamortized discounts of $1.5 million, $0.6 million and $0.2 million, respectively which we used to repay funds borrowed under the revolver portion of our Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing April 1, 2011. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters fees and related expense are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

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The 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 these notes. The securities 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 March 31, 2011, is as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
			(Millions)		
Long-term debt (a)	$ 749.8	$ 25.2	$ 456.8	$ 267.8	$
Operating lease obligations (b)	39.3	15.2	20.5	2.5	1.1
Purchase obligations (c)	599.0	413.4	84.7	67.4	33.5
Other long-term liabilities (d)	12.8	0.7	0.5	0.3	11.3
Total	$ 1,400.9	$ 454.5	$ 562.5	$ 338.0	$ 45.9

(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 firm transportation arrangements and natural gas storage for our Pelico system. The firm transportation arrangements supply off-system natural gas to Pelico and 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 $2.0 million of purchase orders for capital expenditures and $597.0 million of various non-cancelable commitments to purchase physical quantities of propane supply for our Wholesale Propane Logistics business. For contracts where the price paid is based on an index, the amount is based on the forward market prices at March 31, 2011. 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 $10.9 million of asset retirement obligations and $1.9 million of environmental reserves recognized in the March 31, 2011 condensed consolidated balance sheet.

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

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Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2010-29 Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations*, or ASU 2010-29** In December 2010, the FASB issued ASU 2010-29 which amended Accounting Standards Codification, or ASC, Topic 805 Business Combinations to specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the year had occurred as of the beginning of the comparable prior annual reporting period only. The ASU also expands the supplemental pro forma disclosures under Topic 805 to include a description of the nature and the amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after January 1, 2011. The provisions of ASU 2010-29 impact disclosure only. We have not had any business combinations that fall under the guidance of ASU 2010-29 and consequently, there was no impact on our disclosures as a result of adoption.

***ASU 2010-28 Intangibles Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts*, or ASU 2010-28** In December 2010, the FASB issued ASU 2010-28 which amended ASC Topic 350 Intangibles Goodwill and Other . ASU 2010-28 requires an entity with reporting units that have carrying amounts that are zero or negative to assess whether it is more likely than not that the reporting units goodwill is impaired. If the entity determines that it is more likely than not that the goodwill of one or more of its reporting units is impaired, the entity is required to perform Step 2 of the goodwill impairment test for those reporting unit(s) and record any resulting impairment as a cumulative-effect adjustment to beginning retained earnings. The provisions of ASU 2010-28 became effective for us on January 1, 2011. We do not have any reporting units that fall under the guidance of ASU 2010-28 and consequently, there was no effect on our condensed consolidated results of operations, cash flows or financial position as a result of adoption.

***ASU, 2010-06 Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements*, or ASU 2010-06** In January 2010, the FASB issued ASU 2010-06 which amended ASC Topic 820-10 Fair Value Measurement and Disclosures Overall. ASU 2010-06 requires new disclosures regarding transfers in and out of assets and liabilities measured at fair value classified within the valuation hierarchy as either Level 1 or Level 2 and information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3. ASU 2010-06 clarifies existing disclosures on the level of disaggregation required and inputs and valuation techniques. The provisions of ASU 2010-06 became effective for us on January 1, 2010, except for disclosure of information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3, which became effective for us on January 1, 2011. The provisions of ASU 2010-06 impact only disclosures and we have disclosed information in accordance with the provisions of ASU 2010-06 within this filing.

***ASU 2009-13 Revenue Recognition (Topic 605) Multiple-Deliverable Revenue Arrangements*, or ASU 2009-13** In October 2009, the FASB issued ASU 2009-13 which amended ASC Topic 605 Revenue Recognition. The ASU addresses the accounting for multiple-deliverable arrangements, to enable vendors to account for products or services separately rather than as a combined unit. ASU 2009-13 became effective for us on January 1, 2011 and there was no impact on our condensed consolidated results of operations, cash flows and financial position as a result of adoption.

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 2010 Form 10-K.

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, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations.

At March 31, 2011, we had interest rate swap agreements totaling $450 million, of which we have designated $425.0 million as cash flow hedges and account for the remaining $25.0 million under the mark-to-market method of accounting. As we generally expect to have variable rate debt levels equal to or exceeding our swap positions during their term, the entire $450.0 million of these arrangements generally mitigate our interest rate risk through June 2012, with $150 million extending from June 2012 through June 2014. Based on our current operations we believe our interest rate swap agreements adequately mitigate our interest rate risk associated with our variable rate debt.

At March 31, 2011, the effective weighted-average interest rate on our outstanding debt was 4.25%, taking into account our interest rate swap agreements totaling $450.0 million.

Based on the annualized unhedged borrowings under our credit facility of $1.0 million as of March 31, 2011, a 0.5% movement in the base rate or LIBOR rate would have an immaterial impact on interest expense.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering services, we receive fees or commodities from producers to bring the natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, depending on the types of contracts. For storage services, we receive fees in the form of cash or commodities as payment for these services. 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.

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

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

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

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

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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 May 6, 2011:

Commodity Oil Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Reference Price	Price Range
April 2011 December 2014	Natural Gas	(500) MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a)	$5.06/MMBtu
April 2011 December 2014	Natural Gas	(1000) MMBtu/d	Texas Gas Transmission Price (b)	$4.87/MMBtu
April 2011 December 2011	Natural Gas	(400) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (d)	$4.21/MMBtu
April 2011 September 2011	NGL s	(2,476) Bbls/d	Mt.Belvieu Non-TET (e)	$.55-2.52/Gal
October 2011 December 2011	NGL s	(1,237) Bbls/d	Mt.Belvieu Non-TET (e)	$.55-2.52/Gal
April 2011 December 2011	Crude Oil	(2,200) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$56.75 - $83.80/Bbl
January 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
April 2011 December 2014	Natural Gas	500 MMBtu/d	Texas Gas Transmission Price (b)	$4.93/MMBtu
April 2011 September 2011	Crude Oil	1,550 Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$106.58-109.85/Bbl
October 2011 December 2011	Crude Oil	765 Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$107.30-109.85/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 Inside FERC monthly published index price for natural gas delivered into the Houston Ship Channel area.
(e) The average monthly OPIS price for Mt. Belvieu Non-TET.

Commodity Collar Arrangements

Period	Commodity	Notional Volume	Reference Price	Collar Price Range
April 2011 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 2011 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 2011, and exclude the impact from non-cash mark-to-market on our commodity derivatives. We utilize crude oil and NGL derivatives to mitigate a portion of our commodity price exposure for NGLs, and show our sensitivity to changes in the relationship between the pricing of NGLs and crude oil. For fixed price natural gas and crude oil, the sensitivities are associated with our unhedged volumes. For our NGL to crude oil price relationship, the sensitivity is associated with both hedged and unhedged equity volumes.

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Commodity Sensitivities Excluding Non-Cash Mark-To-Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 0.4
Crude oil prices (a)	$ 5.00	Barrel	$ 3.2
NGL to crude oil price relationship (b)	5 percentage point change	Barrel	$ 5.7

(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 $80.00/Bbl crude oil price. Generally, this sensitivity changes by $0.7 million for each $10.00/Bbl change in the price of crude oil. As crude oil prices increase from $80.00/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 $80.00/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 2011 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income Attributable to Partners) (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 1.4
Crude oil prices	$ 5.00	Barrel	$ 15.0
NGL prices	$ 0.10	Gallon	$ 2.1

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.

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

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

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 March 31, 2011, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of March 31, 2011, 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 March 31, 2011 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 2010 Form 10-K, which 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 2010 Form 10-K. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described in our 2010 Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our condensed consolidated results of operations, financial condition and cash flows.

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Item 6. Exhibits *Exhibits*

Exhibit Number	Description
3.1 *	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP (attached as Exhibit 3.4 to DCP Midstream Partners, LP s Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.2 *	First Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC (attached as Exhibit 3.6 to DCP Midstream Partners, LP s Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.3 *	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP s Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.4 *	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated as of January 20, 2009 and Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP s Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.5 *	Amendment No. 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 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 Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
10.1*	Amended and Restated Credit Agreement, dated June 21, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association as Administrative Agent (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 10-Q (File No. 001-32678) filed with the SEC on November 9, 2010).
10.2*	Twelfth Amendment to Omnibus Agreement, dated January 1, 2011, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.19 to DCP Midstream Partners, LP s Form 10-K (File No. 001-32678) filed with the SEC on March 1, 2011).
10.3*	First Amendment to Amended and Restated General Partnership Agreement of DCP Southeast Texas, LLC, Gas Supply Resources Holdings, Inc. and DCP Partners SE Texas, LLC (attached as Exhibit 10.22 to DCP Midstream Partners, LP s Form 10-K (File No. 001-32678) filed with the SEC on March 1, 2011).
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 months ended March 31, 2011, 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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on May 10, 2011.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

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

By: /s/ Angela A. Minas
Name: Angela A. Minas
Title: Vice President and Chief Financial Officer
(Principal Financial Officer)

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