Constellation Energy Partners LLC
Form 10-Q
August 14, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2013

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 001-33147

Constellation Energy Partners LLC

(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State of** **organization)**	**11-3742489** **(I.R.S. Employer** **Identification No.)**
1801 Main Street, Suite 1300 **Houston, Texas** **(Address of Principal Executive Offices)**	**77002** **(Zip Code)**

Telephone Number: (832) 308-3700

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 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 ¨	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company x

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

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date.

Common Units outstanding on August 14, 2013: 28,465,148 units.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Balance Sheets

	June 30, 2013 (Unaudited)	December 31, 2012
	(In 000 s except unit data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 9,541	$ 1,959
Accounts receivable	4,442	5,615
Prepaid expenses	1,386	1,309
Risk management assets (see Note 4)	13,912	17,965
Current assets from discontinued operations		1,886
Total current assets	29,281	28,734
Oil and natural gas properties (See Note 6)		
Oil and natural gas properties, equipment and facilities	599,336	594,020
Material and supplies	1,282	771
Less accumulated depreciation, depletion, amortization, and impairments	(483,726)	(474,669)
Net oil and natural gas properties	116,892	120,122
Other assets		
Debt issue costs (net of accumulated amortization of $8,953 and $7,775, respectively)	830	1,168
Risk management assets (see Note 4)	7,032	7,431
Other non-current assets	4,232	3,194
Long-term assets from discontinued operations		67,373
Total assets	$ 158,267	$ 228,022
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 581	$ 480
Accrued liabilities	7,829	7,174
Royalty payable	1,373	1,418
Risk management liabilities (see Note 4)		523
Debt		50,000
Current liabilities from discontinued operations		1,578
Total current liabilities	9,783	61,173
Other liabilities		
Asset retirement obligation	8,036	7,665
Risk management liabilities (see Note 4)		637
Other non-current liabilities	1,978	589
Debt	34,000	34,000
Other long-term liabilities from discontinued operations		7,692
Total other liabilities	44,014	50,583

Total liabilities	53,797	111,756
Commitments and contingencies (See Note 8)		
Members equity		
Class A units, 484,097 and 483,418 units authorized, issued and outstanding, respectively	2,090	2,326
Class B units, 24,124,378 and 24,124,378 units authorized, respectively, and 23,720,732 and 23,687,507 issued and outstanding, respectively	102,380	113,940
Total members equity	104,470	116,266
Total liabilities and members equity	$ 158,267	$ 228,022

See accompanying notes to condensed consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

(Unaudited)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(In 000 s except unit data)			
Revenues				
Natural gas sales	$ 10,025	$ 2,741	$ 11,417	$ 21,345
Oil and liquids sales	5,363	6,458	9,071	8,468
Total revenues (see Note 4)	15,388	9,199	20,488	29,813
Expenses:				
Operating expenses:				
Lease operating expenses	3,905	4,687	8,141	9,858
Cost of sales	379	251	799	636
Production taxes	622	365	1,109	767
General and administrative	3,737	3,705	8,141	7,541
Gain on sale of assets	(17)	(4)	(23)	
Depreciation, depletion, and amortization	4,767	2,318	9,565	4,705
Asset impairments				107
Accretion expense	123	115	246	229
Total operating expenses	13,516	11,437	27,978	23,843
Other expenses (income)				
Interest expense	864	1,437	2,216	3,056
Other expense (income)	(104)	4	(172)	(93)
Total other expenses	760	1,441	2,044	2,963
Total expenses	14,276	12,878	30,022	26,806
Income (loss) from continuing operations	$ 1,112	$ (3,679)	$ (9,534)	$ 3,007
Discontinued operations	$	$ (1,331)	$ (2,686)	$ (2,132)
Net income (loss)	$ 1,112	$ (5,010)	$ (12,220)	$ 875
Change in fair value of commodity hedges		65		88
Cash settlement of commodity hedges		(1,927)		(2,645)
Other comprehensive loss		(1,862)		(2,557)
Comprehensive income (loss)	$ 1,112	$ (6,872)	$ (12,220)	$ (1,682)
Earnings (loss) per unit (see Note 2)				
Earnings (loss) from continuing operations per unit Basic	$ 0.05	$ (0.15)	$ (0.40)	$ 0.12
Earnings (loss) from discontinued operations per unit Basic	$	$ (0.06)	$ (0.11)	$ (0.08)
Net Earnings (loss) per unit Basic	**$ 0.05**	**$ (0.21)**	**$ (0.51)**	**$ 0.04**
Units outstanding Basic	23,829,650	24,159,301	23,799,631	24,173,012

Earnings (loss) from continuing operations per unit Diluted	$	0.05	$	(0.15)	$	(0.40)	$	0.12
Earnings (loss) from discontinued operations per unit Diluted	$		$	(0.06)	$	(0.11)	$	(0.08)
Net Earnings (loss) per unit Diluted	**$**	**0.05**	**$**	**(0.21)**	**$**	**(0.51)**	**$**	**0.04**
Units outstanding Diluted		24,205,102		24,159,301		23,799,631		24,232,246
Distributions declared and paid per unit	$	0.00	$	0.00	$	0.00	$	0.00

See accompanying notes to condensed consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	Six months ended June 30, 2013	2012
	(In 000 s)	
Cash flows from operating activities:		
Net income (loss)	$ (12,220)	$ 875
Adjustments to reconcile net income (loss) to cash provided by operating activities		
Depreciation, depletion and amortization	9,565	4,705
Asset impairments (see Note 6)		107
Amortization of debt issuance costs	1,178	646
Accretion expense	246	229
Equity (earnings) losses in affiliate	(172)	(108)
Gain from disposition of property and equipment	(23)	
Bad debt expense	15	26
(Gain) Loss from mark-to-market activities	3,290	(2,310)
Unit-based compensation programs	609	665
Discontinued operations	2,686	2,132
Changes in Assets and Liabilities:		
(Increase) decrease in accounts receivable	1,160	1,055
(Increase) decrease in prepaid expenses	(77)	(48)
(Increase) decrease in other assets	(1,149)	(599)
Increase (decrease) in accounts payable	101	87
Increase (decrease) in accrued liabilities	(1,391)	(3,541)
Increase (decrease) in royalty payable	(45)	(197)
Increase (decrease) in other liabilities	1,139	354
Net cash provided by continuing operations	4,912	4,078
Net cash provided by discontinued operations	1,062	1,291
Net cash provided by operating activities	5,974	5,369
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(130)	
Development of oil and natural gas properties	(6,319)	(6,807)
Proceeds from sale of assets	58,987	1,505
Distributions from equity affiliate	95	100
Net cash provided by (used in) continuing operations	52,633	(5,202)
Net cash used in discontinued operations		(62)
Net cash provided by (used in) investing activities	52,633	(5,264)
Cash flows from financing activities:		
Members distributions		
Proceeds from issuance of debt	194	
Repayment of debt	(50,194)	(10,000)
Units tendered by employees for tax withholdings	(185)	(183)
Debt issue costs	(840)	(3)

Net cash used in continuing operations	(51,025)	(10,186)
Net cash used in discontinued operations		
Net cash used in financing activities	(51,025)	(10,186)
Net (decrease) increase in cash and cash equivalents	7,582	(10,081)
Cash and cash equivalents, beginning of period	1,959	17,176
Cash and cash equivalents, end of period	$ 9,541	$ 7,095
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ (351)	$ 745
Cash received during the period for interest	$	$ 1
Cash paid during the period for interest	$ (1,012)	$ (1,974)

See accompanying notes to condensed consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Members Equity

(Unaudited)

	Class A		Class B		Accumulated Other Comprehensive Income (Loss)	Total Members Equity
	Units	Amount	Units	Amount		
			(In 000 s, except unit data)			
Balance, December 31, 2012	483,418	$ 2,326	23,687,507	$ 113,940	$	$ 116,266
Distributions						
Units tendered by employees for tax withholding	(2,853)	(4)	(139,810)	(181)		(185)
Unit-based compensation programs	3,532	12	173,035	597		609
Net income (loss)		(244)		(11,976)		(12,220)
Balance, June 30, 2013	484,097	$ 2,090	23,720,732	$ 102,380	$	$ 104,470

See accompanying notes to condensed consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

The consolidated financial statements as of, and for the period ended, June 30, 2013, are unaudited, but in the opinion of management include all adjustments (consisting only of normal recurring adjustments) necessary for a fair statement of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (U.S. GAAP) have been condensed or omitted under Securities and Exchange Commission (SEC) rules and regulations. The results reported in these unaudited consolidated financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

The financial information included herein should be read in conjunction with the financial statements and notes in the Company s Annual Report on Form 10-K for the year ended December 31, 2012, which was filed on March 11, 2013. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2013 financial statement presentation and to reflect our discontinued operations.

Constellation Energy Partners LLC (CEP , we , us , our or the Company) was organized as a limited liability company on February 7, 2005, u the laws of the State of Delaware. We completed our initial public offering on November 20, 2006, and currently trade on the NYSE MKT LLC (NYSE MKT) under the symbol CEP . Through subsidiaries, both PostRock Energy Corporation (NASDAQ: PSTR) (PostRock) and Exelon Corporation (NYSE: EXC) (Exelon), own a portion of our outstanding units. As of June 30, 2013, Constellation Energy Partners Management, LLC (CEPM), a subsidiary of PostRock, owned all of our Class A units and 5,918,894 of our Class B common units, and Constellation Energy Partners Holdings, LLC (CEPH), a subsidiary of Exelon, owned all of our Class C management incentive interests and all of our Class D interests.

We are currently focused on the development and acquisition of oil and natural gas properties in the Cherokee Basin in Kansas and Oklahoma, the Woodford Shale in Oklahoma, and the Central Kansas Uplift in Kansas.

Accounting policies used by us conform to U.S. GAAP. The accompanying financial statements include the accounts of us and our wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. We operate our oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas. Our management evaluates performance based on one business segment as there are not different economic environments within the operation of our oil and natural gas properties.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2012.

Earnings per Unit

Basic earnings per unit (EPU) are computed by dividing net income attributable to unitholders by the weighted average number of units outstanding during each period. At June 30, 2013, we had 484,097 Class A units and 23,720,732 Class B common units outstanding. Of the Class B common units, 375,452 units are restricted unvested common units granted and outstanding.

The following table presents earnings per common unit amounts:

	Income (Loss)	Weighted Average Units Outstanding	Per Unit Amount
		(In 000 s except unit data)	

For the three months ended June 30, 2013			
Basic EPU:			
Income (loss) from continuing operations allocable to unitholders	$ 1,112	23,829,650	$ 0.05
Income (loss) from discontinued operations allocable to unitholders	$		$
Income (loss) allocable to unitholders	$ 1,112	23,829,650	$ 0.05

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	Income (Loss)	Weighted Average Units Outstanding (In 000 s except unit data)	Per Unit Amount
Diluted EPU:			
Income (loss) from continuing operations allocable to unitholders	$ 1,112	24,205,102	$ 0.05
Income (loss) from discontinued operations allocable to unitholders	$		$
Income (loss) allocable to unitholders	$ 1,112	24,205,102	$ 0.05

	Income (Loss)	Weighted Average Units Outstanding (In 000 s except unit data)	Per Unit Amount
For the six months ended June 30, 2013			
Basic EPU:			
Income (loss) from continuing operations allocable to unitholders	$ (9,534)	23,799,631	$ (0.40)
Income (loss) from discontinued operations allocable to unitholders	$ (2,686)		$ (0.11)
Income (loss) allocable to unitholders	$ (12,220)	23,799,631	$ (0.51)
Diluted EPU:			
Income (loss) from continuing operations allocable to unitholders	$ (9,534)	23,799,631	$ (0.40)
Income (loss) from discontinued operations allocable to unitholders	$ (2,686)		$ (0.11)
Income (loss) allocable to unitholders	$ (12,220)	23,799,631	$ (0.51)

	Income (Loss)	Weighted Average Units Outstanding (In 000 s except unit data)	Per Unit Amount
For the three months ended June 30, 2012			
Basic EPU:			
Income (loss) from continuing operations allocable to unitholders	$ (3,679)	24,159,301	$ (0.15)
Income (loss) from discontinued operations allocable to unitholders	$ (1,331)		$ (0.06)
Income (loss) allocable to unitholders	$ (5,010)	24,159,301	$ (0.21)
Diluted EPU:			
Income (loss) from continuing operations allocable to unitholders	$ (3,679)	24,159,301	$ (0.15)
Income (loss) from discontinued operations allocable to unitholders	$ (1,331)		$ (0.06)
Income (loss) allocable to unitholders	$ (5,010)	24,159,301	$ (0.21)

	Income (Loss)	Weighted Average Units Outstanding (In 000 s except unit data)	Per Unit Amount
For the six months ended June 30, 2012			
Basic EPU:			
Income (loss) from continuing operations allocable to unitholders	$ 3,007	24,173,012	$ 0.12
Income (loss) from discontinued operations allocable to unitholders	$ (2,132)		$ (0.08)
Income (loss) allocable to unitholders	$ 875	24,173,012	$ 0.04
Diluted EPU:			
Income (loss) from continuing operations allocable to unitholders	$ 3,007	24,232,246	$ 0.12

Income (loss) from discontinued operations allocable to unitholders	$ (2,132)		$ (0.08)
Income (loss) allocable to unitholders	$ 875	24,232,246	$ 0.04

Cash

All highly liquid investments with original maturities of three months or less are considered cash. Checks-in-transit are included in our consolidated balance sheets as accounts payable or as a reduction of cash, depending on the type of bank account the checks were drawn on. Our checks-in-transit reported in accounts payable were none at June 30, 2013, and $0.5 million at December 31, 2012.

We have established an escrow account for $0.6 million related to a vendor dispute, which is included in other non-current assets in our consolidated balance sheets at June 30, 2013, and December 31, 2012. This amount will remain in the escrow account until the dispute has been resolved. We also have an escrow account for approximately $1.2 million related to the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama, which is included in other non-current assets in our consolidated balance sheets at June 30, 2013. These funds will be held in escrow for a period up to twenty-four months pending certain closing conditions.

3. RECENT ACCOUNTING PRONOUNCEMENTS AND ACCOUNTING CHANGES

In December 2011, the Financial Accounting Standards Board (FASB) issued ASU No. 2011-11, *Disclosures about Offsetting Assets and Liabilities,* which requires additional disclosures for financial and derivative instruments that are either (1) offset in accordance with either Accounting Standards Codification (ASC) 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, regardless of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. The guidance was effective beginning on or after January 1, 2013, and primarily impacts the disclosures associated with our commodity and interest rate derivatives. Implementation of this guidance did not have any material impact on our consolidated financial position, results of operations or cash flows.

4. DERIVATIVE AND FINANCIAL INSTRUMENTS

Mark-to-Market Activities

As of June 30, 2013, we have hedged a portion of our expected natural gas and oil sales from currently producing wells through December 2016. All of our derivatives were accounted for as mark-to-market activities as of June 30, 2013.

For the six months ended June 30, 2013 and 2012, we recognized mark-to-market losses of approximately $6.9 million and mark-to-market gains of approximately $1.7 million, respectively, in connection with our commodity derivatives. For the six months ended June 30, 2013 and 2012, we recognized a mark-to-market gain of approximately $3.6 million and $0.6 million, respectively, in connection with our interest rate derivatives. At June 30, 2013 and December 31, 2012, the fair value of our derivatives accounted for as mark-to-market activities amounted to a net asset of approximately $20.9 million and $24.2 million, respectively.

Fair Value Measurements

We measure fair value of our financial and non-financial assets and liabilities on a recurring basis. Accounting standards define fair value, establish a framework for measuring fair value and require certain disclosures about fair value measurements for assets and liabilities measured on a recurring basis. All of our derivative instruments are recorded at fair value in our financial statements. Fair value is the exit price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

The following hierarchy prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices available in active markets for identical assets or liabilities as of the reporting date.

Level 2 Pricing inputs other than quoted prices in active markets included in Level 1 which are either directly or indirectly observable as of the reporting date. Level 2 consists primarily of non-exchange traded commodity and interest rate derivatives.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources.

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We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices, and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates, and an appropriate discount rate. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use in determining fair value. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Because of the long-term nature of certain assets and liabilities measured at fair value as well as differences in the availability of market prices and market liquidity over their terms, inputs for some assets and liabilities may fall into any one of the three levels in the fair value hierarchy. While we are required to classify these assets and liabilities in the lowest level in the hierarchy for which inputs are significant to the fair value measurement, a portion of that measurement may be determined using inputs from a higher level in the hierarchy.

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were measured at fair value on a recurring basis as of June 30, 2013 and December 31, 2012.

At June 30, 2013	**Commodity and Interest Rate Derivatives Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral***	**Total Net Fair Value**
			(In 000 s)		
Risk management assets	$	$ 22,517	$	$ (1,573)	$ 20,944
Risk management liabilities	$	$ (1,573)	$	$ 1,573	$
Total net assets and liabilities	$	$ 20,944	$	$	$ 20,944

At December 31, 2012	**Commodity and Interest Rate Derivatives Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral***	**Total Net Fair Value**
			(In 000 s)		
Risk management assets	$	$ 31,030	$	$ (5,634)	$ 25,396
Risk management liabilities	$	$ (6,794)	$	$ 5,634	$ (1,160)
Total net assets and liabilities	$	$ 24,236	$	$	$ 24,236

* *We currently use our reserve-based credit facility to provide credit support for our derivative transactions and therefore we do not post cash collateral with our counterparties. Amounts shown represent the impact of netting assets and liabilities with our counterparties for which the right of offset exists.*

Risk management assets and liabilities in the table above represent the current fair value of all open derivative positions. We classify all of our derivative instruments as Risk management assets or Risk management liabilities in our Consolidated Balance Sheets.

We use observable market data or information derived from observable market data in order to determine the fair value amounts presented above. We currently use our reserve-based credit facility to provide credit support for our derivative transactions. As a result, we do not post cash collateral with our counterparties, and have minimal non-performance credit risk on our liabilities with counterparties. We utilize observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating our net assets from counterparties. At June 30, 2013, the impact of non-performance credit risk on the valuation of our net assets from counterparties was $0.1 million, of which $0.1 million was reflected as a decrease to our non-cash mark-to-market gain and none was reflected as a reduction to our accumulated other comprehensive income. At June 30, 2012, the impact of non-performance credit risk on the valuation of our net assets from counterparties was $0.5 million, of which $0.4 million was reflected as a decrease to our non-cash mark-to-market gain and $0.1 million was reflected in our accumulated other comprehensive loss.

Fair Value of Financial Instruments

As of June 30, 2013, we have various commodity swaps for 15,316,767 MMbtu of natural gas production through December 2016, various basis swaps for 6,941,187 MMbtu of natural gas production in the Cherokee Basin through December 2014, and various commodity swaps for 335,651 Bbls of oil production through December 2016. We had no interest rate swaps at June 30, 2013.

Under the terms of our reserve-based credit facility, we have agreed to hedge at least 100% of our reasonably estimated projected natural gas production for 2015 and 50% of our reasonably estimated projected natural gas production for 2016. All of the required 2015 hedges are in place, and we have agreed to enter into the remaining 2016 hedges on or before December 31, 2013. In the event that the 2016 hedges are not in place by December 31, 2013, our borrowing base will automatically be reduced by the shortfall of actual hedges as compared to 50% of the reasonably estimated projected natural gas production, not to exceed an amount equal to $3.0 million times the calculated percentage of hedging shortfall. We expect to enter into the 2016 hedges prior to December 31, 2013.

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The following represents the fair value for our risk management assets and liabilities, as of June 30, 2013, and December 31, 2012, and the amount of gains and losses recognized at June 30, 2013 and 2012:

Derivative Type	Location of Asset/ (Liability) on Balance Sheet	Fair Value of Asset/ (Liability) on Balance Sheet (in 000 s) June 30, 2013	December 31, 2012
Commodity-MTM	Risk management assets-current	$ 15,134	$ 19,005
Commodity-MTM	Risk management assets-non-current	7,383	12,025
	Total gross assets	22,517	31,030
Commodity-MTM	Risk management assets-current	(1,222)	(1,040)
Commodity-MTM	Risk management assets-non-current	(351)	(946)
Commodity-MTM	Risk management liabilities-current	(0)	(523)
Commodity-MTM	Risk management liabilities-non-current	(0)	(637)
Interest Rate-MTM	Risk management assets-non-current	(0)	(3,648)
	Total gross liabilities	(1,573)	(6,794)
	Total net assets and liabilities	$ 20,944	$ 24,236

Derivative Type	Location of Gain /(Loss) in Income	Amount of Gain / (Loss) in Income (in 000 s) Quarter Ended June 30, 2013	Quarter Ended June 30, 2012
Commodity-MTM-Unrealized	Natural gas sales	$ 1,352	$ (8,455)
Commodity-MTM-Unrealized	Oil and liquids sales	994	3,558
Commodity-MTM-Realized	Natural gas sales	2,730	7,307
Commodity-MTM-Realized	Oil and liquids sales	346	34
Interest Rate-MTM-Unrealized	Interest expense	984	513
Interest Rate-MTM-Realized	Interest expense	(1,003)	(793)
	Total	$ 5,403	$ 2,164

Derivative Type	Location of Gain / (Loss) in Income	Amount of Gain / (Loss) in Income (in 000 s) Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Commodity-MTM-Unrealized	Natural gas sales	$ (7,129)	$ (583)
Commodity-MTM-Unrealized	Oil and liquids sales	190	2,288
Commodity-MTM-Realized	Natural gas sales	7,274	13,266
Commodity-MTM-Realized	Oil and liquids sales	507	123
Interest Rate-MTM-Unrealized	Interest expense	3,648	605
Interest Rate-MTM-Realized	Interest expense	(3,713)	(1,285)
	Total	$ 777	$ 14,414

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Derivative Type	Location of Gain/(Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income - Effective Quarter Ended June 30, 2013	Quarter Ended June 30, 2012
Commodity-Cash Flow	Natural gas sales	$	$ 1,927
	Total	$	$ 1,927

Derivative Type	Location of Gain/(Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income - Effective Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Commodity-Cash Flow	Natural gas sales	$	$ 2,645
	Total	$	$ 2,645

At June 30, 2013, the carrying values of our cash, accounts receivable, other current assets and current liabilities on the Consolidated Balance Sheets approximate fair value because of their short-term nature.

We believe the carrying value of long-term debt for our reserve-based credit facility approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms, which is a Level 2 measurement in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. Our reserve-based credit facility is discussed in Note 5.

Hedge Liquidation, Repositioning and Novation

In the first quarter of 2013, we liquidated or repositioned certain of our hedges. In connection with the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama, we liquidated 395,218 MMbtu of NYMEX swaps in 2013 and 1,634,530 MMbtu of NYMEX swaps in 2014 at a cost of $0.3 million. In addition, we reduced our outstanding NYMEX swap positions in 2013 by 1,041,814 MMbtu by executing offsetting trades with our counterparties at a fixed price of $3.662. These transactions ensure that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods.

In March 2013, we reduced our outstanding interest rate swaps that fix our LIBOR rate through 2014 to $30 million, which increased our interest rate swap settlements by $2.1 million. This position was closed in May 2013 resulting in an offsetting non-cash gain in our mark-to-market interest swap activities. We also amended a 2014 to 2015 oil trade with one of our hedge counterparties to lower the stated swap price from $98.10 to $93.50, on a total of 58,157 barrels of oil. We received proceeds of approximately $0.2 million upon execution of the amendment. The proceeds were used for working capital purposes.

5. DEBT

Reserve-Based Credit Facility

In May 2013, we amended our existing reserve-based credit facility. This amendment increased our borrowing capacity, extended the maturity date and changed the lenders participating in the facility.

At June 30, 2013, we had a $350.0 million reserve-based credit facility with Societe Generale as administrative and collateral agent and a syndicate of lenders. The reserve-based credit facility had a borrowing base of $55.0 million and matures on May 30, 2017. At June 30, 2013, we had $34.0 million in borrowings outstanding, which is reflected as a non-current liability on our balance sheet. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The lenders and their percentage commitments in the reserve-based credit facility are Societe Generale (36.36%), OneWest Bank, FSB (36.36%), and BOKF NA, dba Bank of Oklahoma (27.28%).

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At our election, interest for borrowings are determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 2.50% and 3.50% per annum based on utilization or (ii) a domestic bank rate (ABR) plus an applicable margin between 1.50% and 2.50% per annum based on utilization plus (iii) a commitment fee of 0.50% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The reserve-based credit facility contains various covenants that limit, among other things, our ability and certain of our subsidiaries ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions. The reserve-based credit facility limits our ability to pay distributions to unitholders and permits us to hedge our projected monthly production and the interest rate on our borrowings.

Debt Issue Costs

During the six months ended June 30, 2013, we accelerated the amortization of approximately $0.7 million in debt issue costs as a result of amendments to and refinancing of our reserve-based credit facility. Accelerated amortization of the debt issue costs was required as the syndicate of lenders participating in the reserve-based credit facility changed. As of June 30, 2013, our unamortized debt issue costs were approximately $0.8 million. These costs are being amortized over the life of our reserve-based credit facility.

Funds Available for Borrowing

As of June 30, 2013 and 2012, we had $34.0 million and $88.4 million, respectively, in outstanding debt under our reserve-based credit facility. As of June 30, 2013, we had $21.0 million in remaining borrowing capacity under our reserve-based credit facility.

Compliance with Debt Covenants

At June 30, 2013, we were in compliance with the financial covenants contained in our reserve-based credit facility.

6. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consist of the following:

	June 30, 2013	December 31, 2012
	(In 000 s)	
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 597,178	$ 591,889
Unproved property	1,407	1,380
Total property costs	598,585	593,269
Materials and supplies	1,282	771
Land	751	751
Total	600,618	594,791
Less: Accumulated depreciation, depletion, amortization and impairments	(483,726)	(474,669)
Oil and natural gas properties and equipment, net	$ 116,892	$ 120,122

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Depletion, depreciation, amortization and impairments consist of the following:

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(In 000 s)	
DD&A of oil and natural gas-related assets	$ 9,565	$ 4,705
Asset Impairments		107
Total	$ 9,565	$ 4,812

Impairment of Oil and Natural Gas Properties and Other Non-Current Assets

In March 2012, we recorded a total non-cash impairment charge of approximately $0.1 million to impair certain of our wells in the Woodford Shale. This impairment was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in a third party reserve report. This report was based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 2 inputs in the fair value hierarchy. Significant assumptions in valuing the proved reserves included the reserve quantities, anticipated operating costs, anticipated production taxes, future expected oil and natural gas prices and basis differentials, anticipated production declines, and an appropriate discount rate commensurate with the risk of the underlying cash flow estimates for the properties of 10.0%. The impairment was primarily caused by the impact of lower future expected oil and natural gas prices on future expected cash flows during the first quarter of 2012. After the impairments, the remaining net capitalized costs subject to impairment in the Woodford Shale was approximately $3.6 million. Cash flow estimates for the impairment testing exclude derivative instruments used to mitigate the risk of lower future oil and natural gas prices. These asset impairments have no impact on our cash flows, liquidity position, or debt covenants.

Asset Sales

On February 28, 2013, we sold our Robinson s Bend Field assets in the Black Warrior Basin of Alabama for $63.0 million, subject to closing adjustments, and recorded a loss on the sale of approximately $3.1 million. These assets were classified as discontinued operations in the first quarter of 2013. In July 2013, we paid the purchaser $1.1 million, which had been held in escrow, based on the final settlement statement. See Note 13 for additional information.

In the six months ended June 30, 2013, we also sold miscellaneous surplus equipment for less than $0.1 million resulting in an immaterial gain on the asset sale. In the six months ended June 30, 2012, we sold our interests in 14 gross non-operated oil wells in Kansas and Nebraska for approximately $1.4 million in cash, resulting in an immaterial loss on the asset sale.

Useful Lives

Our furniture, fixtures, and equipment are depreciated over a life of one to five years, buildings are depreciated over a life of twenty years, and pipeline and gathering systems are depreciated over a life of twenty-five to forty years.

Exploration and Dry Hole Costs

We had no exploration and dry hole costs in the six months ended June 30, 2013 and 2012, respectively. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties.

7. RELATED PARTY TRANSACTIONS

Unit Ownership

Both PostRock and Exelon, through subsidiaries, own a portion of our outstanding units. As of June 30, 2013, CEPM, a subsidiary of PostRock, owned all of our Class A units and 5,918,894 of our Class B common units. CEPH, a subsidiary of Exelon, owned all of our Class C management incentive interests and all of our Class D interests as of June 30, 2013.

Class C Management Incentive Interests

CEPH, a subsidiary of Exelon, held all of the Class C management incentive interests in CEP as of June 30, 2013. These management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our operating agreement) has been achieved and certain other tests have been met. None of these applicable tests have yet to be met and CEPH has not been entitled to receive any management incentive interest distributions.

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8. COMMITMENTS AND CONTINGENCIES

In the course of our normal business affairs, we are subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations and third-party litigation and lawsuits. As of June 30, 2013, there were no matters which, in the opinion of management, would have a material adverse effect on the financial position, results of operations or cash flows of CEP, and its subsidiaries, taken as a whole.

9. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost (ARC) is capitalized as part of the carrying amount of our oil and natural gas properties, equipment and facilities. Subsequently, the ARC is depreciated using a systematic and rational method over the asset s useful life. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells, and decommissioning of oil and natural gas gathering and other facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas property balance. The following table is a reconciliation of the ARO:

	June 30, 2013	December 31, 2012
	(In 000 s)	
Asset retirement obligation, beginning balance	$ 7,665	$ 7,052
Liabilities incurred	128	162
Liabilities settled	(3)	(8)
Revisions to prior estimates		
Accretion expense	246	459
Asset retirement obligation, ending balance	$ 8,036	$ 7,665

Additional asset retirement obligations increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset retirement obligations. At June 30, 2013, and December 31, 2012, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations.

10. COMPENSATION

We recognized approximately $0.6 million and $0.7 million of non-cash compensation expense related to our unit-based compensation plans in the six months ended June 30, 2013, and June 30, 2012, respectively. As of June 30, 2013, we had approximately $0.9 million in unrecognized compensation expense related to our unit-based non-cash compensation plans expected to be recognized through the first quarter of 2015.

In the six months ended June 30, 2013, we incurred one-time severance costs of approximately $1.0 million. This one-time charge was reflected as general and administrative expenses and was composed of approximately $0.8 million in cash compensation expense and approximately $0.2 million in non-cash compensation expense related to accelerated vesting under our unit-based compensation plans.

11. DISTRIBUTIONS TO UNITHOLDERS

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For each of the quarterly periods since June 2009, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

12. MEMBERS EQUITY

2013 Equity

At June 30, 2013, we had 484,097 Class A units and 23,720,732 Class B common units outstanding, which included 44,644 unvested restricted common units issued under our Long-Term Incentive Plan and 330,808 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At June 30, 2013, we had granted 347,602 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 302,958 have vested.

At June 30, 2013, we had granted 1,348,752 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 1,017,944 have vested.

For the six months ended June 30, 2013, 139,810 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, have been returned to their respective plan and are available for future grants.

2012 Equity

At June 30, 2012, we had 483,531 Class A units and 23,693,018 Class B common units outstanding, which included 129,369 unvested restricted common units issued under our Long-Term Incentive Plan and 675,919 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At June 30, 2012, we had granted 345,221 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 215,852 have vested. We also granted an additional 76,046 performance units under our Long-Term Incentive Plan that are subject to performance conditions which vested on January 2, 2013.

At June 30, 2012, we had granted 1,323,419 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 647,500 have vested. We also granted an additional 323,194 performance units under our 2009 Omnibus Incentive Compensation Plan that are subject to performance conditions which vested on January 1, 2013.

For the six months ended June 30, 2012, 78,131 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, have been returned to their respective plan and are available for future grants.

13. DISCONTINUED OPERATIONS

On January 31, 2013, our Board of Managers authorized the sale of the two entities that owned all our natural gas properties and inventory in the Robinson s Bend Field in the Black Warrior Basin of Alabama for $63.0 million, subject to closing adjustments. On February 28, 2013, we sold all of our operations in Alabama, including our interests in 596 operated natural gas wells and all of our inventory and equipment and received approximately $60.0 million in net cash proceeds from the buyer, subject to additional post-closing working capital and other customary adjustments. Of this amount, approximately $1.2 million is being held in escrow for a period of twenty-four months pending certain closing conditions and $50.0 million was used to reduce our outstanding debt under our reserve-based credit facility. In July 2013, we paid the purchaser $1.1 million, which had been held in escrow, based on the final settlement statement.

During the six months ended June 30, 2013, our discontinued operations had a net loss of $2.7 million consisting of revenues of $2.3 million, expenses of $1.9 million, and a loss on sale of $3.1 million. During the six months ended June 30, 2012, our discontinued operations had a net loss of $2.1 million consisting of revenues of $5.8 million and expenses of $7.9 million. During the three months ended June 30, 2012, our discontinued operations had a net loss of $1.3 million consisting of revenues of $2.6 million and expenses of $4.0 million. At December 31, 2012, our discontinued operations had current assets of $1.9 million, long-term assets of $67.4 million, current liabilities of $1.6 million, and long-term liabilities of $7.7 million. The current assets primarily represented accounts receivable for natural gas sales and the current liabilities primarily represented accounts payable and accrued liabilities. Long-term assets represented natural gas properties, equipment and facilities and the long-term liabilities represented asset retirement obligations.

14. SUBSEQUENT EVENTS

The following subsequent events have occurred between June 30, 2013, and August 14, 2013:

Asset Acquisition and Unit Issuance

On August 9, 2013, we entered into a new business relationship with Sanchez Oil & Gas Corporation (SOG) and its affiliate, Sanchez Energy Partners I, LP (SEP I). We acquired oil, natural gas and natural gas liquids assets in Texas and Louisiana from SEP I for a purchase price of $30.4 million. In conjunction with the acquisition, SEP I received $20.1 million in cash, 1,130,512 Class A units, which represents 70.0% of the total Class A units outstanding after the transaction, and 4,724,407 Class B units, which represents 16.6% of the total Class B units outstanding after the transaction. The cash portion of the transaction was financed with cash on hand and a borrowing of $16.7 million under CEP s reserved-based credit facility.

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The acquired assets include 67 wells, 75% operated by SOG, with current net production of approximately 1,167 Boe per day, of which approximately 25% is oil and natural gas liquids production.

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

The following discussion and analysis should be read in conjunction with the financial statements and the summary of significant accounting policies and notes included herein and in our most recent Annual Report on Form 10-K.

Overview

We are a limited liability company formed in 2005 to acquire oil and natural gas properties. All of our oil and natural gas reserves are currently located in the Mid-Continent region of the United States, including the Cherokee Basin of Kansas and Oklahoma, the Woodford Shale in Oklahoma, the Central Kansas Uplift in Kansas and Sanchez Gulf Coast properties in Texas and Louisiana. Our primary business objective is to create long-term value and to generate stable cash flows allowing us to invest in our business to grow our reserves and production. We plan to achieve our objective by executing our business strategy, which is to:

- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth and oil opportunities on our existing properties in the Mid-Continent region;
- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs; and
- make accretive, right-sized acquisitions of oil and natural gas properties characterized by a high percentage of proved developed oil and natural gas reserves with long-lived, stable production and low-risk drilling opportunities.

We completed our initial public offering on November 20, 2006, and our Class B common units are currently listed on the NYSE MKT under the symbol CEP.

Unless the context requires otherwise, any reference in this Quarterly Report on Form 10-Q to Constellation Energy Partners, we, our, us, CEP or the Company means Constellation Energy Partners LLC and its subsidiaries. References in this Quarterly Report on Form 10-Q to PostRock and CEPM are to PostRock Energy Corporation and its subsidiary Constellation Energy Partners Management, LLC, respectively. References in this Quarterly Report on Form 10-Q to Exelon and CEPH are to Exelon Corporation and its subsidiary Constellation Energy Partners Holdings, LLC, respectively. References in this Quarterly Report on Form 10-Q to Constellation, CCG, and CHI are to Constellation Energy Group, Inc., Constellation Energy Commodities Group, Inc., and Constellation Holdings, Inc., respectively.

How We Evaluate our Operations

Non-GAAP Financial Measure Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) adjusted by:

- depreciation, depletion and amortization;
- write-off of deferred financing fees;
- asset impairments;

- (gain) loss on sale of assets;
- accretion expense;
- (gain) loss from equity investment;
- unit-based compensation programs;
- (gain) loss from mark-to-market activities;
- gains (losses) on discontinued operations; and
- interest (income) expense, net which includes:
  - interest expense
  - interest expense gain/(loss) mark-to-market activities
  - interest (income)

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Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any cash reserves by our board of managers) the distributions we would expect to pay to our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support a quarterly distribution or any increase in our quarterly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts, our lenders and others to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

Our Adjusted EBITDA should not be considered as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

We are unable to reconcile our forecast range of Adjusted EBITDA to GAAP net income or operating income because we do not predict the future impact of adjustments to net income (loss), such as (gains) losses from mark-to-market activities and equity investments or asset impairments due to the difficulty of doing so, and we are unable to address the probable significance of the unavailable reconciliation, in significant part due to ranges in our forecast impacted by changes in oil and natural gas prices and reserves which affect certain reconciliation items.

The following table presents a reconciliation of net income (loss) to Adjusted EBITDA, our most directly comparable GAAP performance measure, for each of the periods presented:

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2013	June 30, 2012	June 30, 2013	June 30, 2012
	(In 000 s)			
Net income (loss)	$ 1,112	$ (5,010)	$ (12,220)	$ 875
Adjusted by:				
Interest expense/(income), net	864	1,437	2,216	3,056
Depreciation, depletion and amortization	4,767	2,318	9,565	4,705
Asset impairments				107
Accretion expense	123	115	246	229
(Gain)/Loss on sale of assets	(17)	(4)	(23)	
Unit-based compensation programs	208	385	609	665
(Gain)/Loss on mark-to-market activities	(2,346)	4,897	6,939	(1,705)
Discontinued operations		1,331	2,686	2,132
Adjusted EBITDA	$ 4,711	$ 5,469	$ 10,018	$ 10,064

Our Adjusted EBITDA from our continuing operations was $4.7 million for the three months ended June 30, 2013, which is lower than our Adjusted EBITDA of $5.5 million in the same period in 2012. The decrease is mostly due to gains on our mark-to-market activities, lower production and higher depreciation, depletion and amortization.

Our Adjusted EBITDA was $10.0 million for the six months ended June 30, 2013, lower than our Adjusted EBITDA of $10.1 million in the same period in 2012.

Some key highlights of our business activities through August 14, 2013 were:

- We refinanced our credit facility, and increased our borrowing base from $37.5 million to $55.0 million.

- We sold all of our natural gas properties in the Robinson s Bend Field in the Black Warrior Basin of Alabama in February 2013.

- We have implemented strategies to reduce our general and administrative expenses and our lease operating expenses going forward. During the first six months of 2013, we incurred a general and administrative charges of approximately $1.0 million associated with severance costs. Excluding this charge and non-cash unit-based compensation costs, our six months ended June 30, 2013 cash general and administrative expenses and lease operating expenses decreased by 11.2% as compared to these cash operating expenses for the same time period in 2012.

- Our successful capital expenditure programs have continued to expand our oil production. Our six months ended June 30, 2013 oil production has increased by 54% over our oil production for the same time period in 2012. Oil revenues accounted for 42.6% of our total unhedged revenue stream in 2013.

- We acquired oil, natural gas and natural gas liquids assets in Texas and Louisiana from SEP I for a purchase price of $30.4 million.

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In 2013, we intend to continue focusing our efforts on developing oil opportunities on our existing properties in the Mid-continent region while pursuing opportunities to acquire additional properties in our operating area or merger and acquisition opportunities. Our forecasted capital spending of $19 million to $21 million is unchanged, with maintenance capital spending setting the high end of this range. We anticipate that our 2013 capital expenditures could allow us to maintain our 2013 production at slightly below the same level as in 2012. We intend to manage our business to operate within the cash flows that are generated by our existing asset base.

Significant Operational Factors

Realized Prices. Our average realized price for the six months ended June 30, 2013, was $7.11 per Mcfe including hedge settlements and $5.09 per Mcfe excluding hedge settlements. After deducting the cost of sales associated with our third party gathering, our average realized prices were $6.90 per Mcfe including hedge settlements and $4.88 per Mcfe excluding hedge settlements.

Production. Our production for the six months ended June 30, 2013, was 3.9 Bcfe, or an average of 21,322 Mcfe per day, compared with approximately 4.2 Bcfe, or an average of 22,830 Mcfe per day, for the six months ended June 30, 2012. Our oil production increased 55.2% for the six months ended June 30, 2013 when compared to the same period in 2012. Our 2013 production is lower than the production for the same period in 2012 because of the natural production declines associated with our existing natural gas wells not being fully offset by the impact of our drilling programs which were limited so that our operating cash flows could be used to reduce our outstanding debt level.

Capital Expenditures and Drilling Results. During the first six months of 2013, we spent approximately $6.4 million in cash capital expenditures, consisting of $6.3 million in development expenditures focused on oil completions in the Cherokee Basin and $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin. We have completed 26 net wells and 13 net recompletions during the six months ended June 30, 2013 and have 5 net wells and net recompletions in progress at June 30, 2013. During the fourth quarter of 2012 and the first quarter of 2013, we successfully completed substantially all of the remaining net wells and net recompletions from our 2012 capital program, and the first six months of 2013 daily average net oil production has increased to 500 barrels from our average daily production of 324 barrels for the second quarter of 2012.

Hedging Activities. All of our commodity and interest rate derivatives are accounted for as mark-to-market activities. For the six months ended June 30, 2013, the unrealized non-cash mark-to-market loss for our commodity derivatives was approximately $6.9 million as compared to an unrealized non-cash mark-to-market gain of $1.7 million for the same period in 2012.

We experience earnings volatility as a result of using the mark-to-market accounting method for our open derivative positions. This accounting treatment can cause extreme earnings volatility as the positions for future oil and natural gas production or interest rates are marked-to-market. These non-cash unrealized gains or losses are included in our current statement of operations until the derivatives are cash settled as the commodities are produced and sold or interest payments are made. Further detail of our commodity derivative positions and their accounting treatment is outlined below in Cash Flow From Operations-Open Commodity Hedge Position .

Debt Reduction. We have reduced our outstanding debt from a high of $220.0 million in 2009 to $34.0 million as of June 30, 2013, or by 84.5% in total. At August 14, 2013, we had $50.7 million in outstanding debt with $4.3 remaining in borrowing capacity in connection with our acquisition of SEP I assets.

Operating Expense Reductions. We have implemented strategies to reduce our structural general and administrative expenses by 25% for 2013 and to further reduce our lease operating expenses. These strategies include: reducing headcount in Houston and Oklahoma, closing our technical office in Tulsa, Oklahoma, closing our field office in Dewey, Oklahoma, lowering our annual bonus expense by 50%, reducing executive and board compensation expenses, reducing medical and dental plan expenses by changing providers, reducing the employer match for our 401K program, releasing our strategic advisor, changing certain other professional services providers, terminating our outsource support services agreement for revenue accounting services, and reducing overtime expenses.

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Results of Operations

The following table sets forth the selected financial and operating data for the periods indicated:

	For the Three Months Ended				For the Six Months Ended			
	(Dollars in 000 s)							
	June 30, 2013	June 30, 2012	Variance $	Variance %	June 30, 2013	June 30, 2012	Variance $	Variance %
Revenues:								
Natural gas sales at market price	$ 5,228	$ 3,211	$ 2,017	62.8%	$ 9,619	$ 7,047	$ 2,572	36.5%
Natural gas hedge settlements	2,730	7,307	(4,577)	(62.6)%	7,274	13,265	$ (5,991)	(45.2)%
Natural gas mark-to-market activities	1,352	(8,455)	9,807	(116.0)%	(7,129)	(583)	$ (6,546)	1,122.8%
Natural gas total	9,310	2,063	7,247	351.3%	9,764	19,729	(9,965)	(50.5)%
Oil and liquids sales	$ 4,023	$ 2,866	$ 1,157	40.4%	$ 8,374	$ 6,057	$ 2,317	38.3%
Oil hedge settlements	346	$ 34	312	917.6%	507	123	384	312.2%
Oil mark-to-market activities	994	$ 3,558	(2,564)	(72.1)%	190	2,288	(2,098)	(91.7)%
Oil and liquids total	5,363	6,458	(1,095)	(17.0)%	9,071	8,468	603	7.1%
Other natural gas sales at market price	$ 715	$ 678	$ 37	5.5%	$ 1,653	$ 1,616	$ 37	2.3%
Total revenues	$ 15,388	$ 9,199	$ 6,189	67.3%	$ 20,488	$ 29,813	$ (9,325)	(31.3)%
Operating expenses:								
Lease operating expenses	3,905	4,687	(782)	(16.7)%	8,141	9,858	(1,717)	(17.4)%
Cost of sales	379	251	128	51.0%	799	636	163	25.6%
Production taxes	622	365	257	70.4%	1,109	767	342	44.6%
General and administrative	3,737	3,705	32	0.9%	8,141	7,541	600	8.0%
Gain on sale of assets	(17)	(4)	(13)	325.0%	(23)		(23)	
Depreciation, depletion and amortization	4,767	2,318	2,449	105.7%	9,565	4,705	4,860	103.3%
Asset impairments						107	(107)	(100.0)%
Accretion expenses	123	115	8	7.0%	246	229	17	7.4%
Total operating expenses	13,516	11,437	2,079	18.2%	27,978	23,843	4,135	17.3%
Other expenses (income):								
Interest expense	1,848	1,951	(103)	(5.3)%	5,864	3,662	2,202	60.1%
Interest expense-Gain from mark-to-market activities	(984)	(513)	(471)	91.8%	(3,648)	(605)	(3,043)	503.0%
Interest income		(1)	1	(100.0)%		(1)	1	(100.0)%
Other (income) expense	(104)	4	(108)	(2,700.0)%	(172)	(93)	(79)	84.9%
Total other expenses	760	1,441	(681)	(47.3)%	2,044	2,963	(919)	(31.0)%
Total expenses	14,276	12,878	1,398	10.9%	30,022	26,806	3,216	12.0%
Discontinued operations		(1,331)	1,331	(100.0)%	(2,686)	(2,132)	(554)	26.0%
Net income (loss)	$ 1,112	$ (5,010)	$ 6,122	(122.2)%	$ (12,220)	$ 875	$ (13,095)	(1,496.6)%
Net production:								
Natural gas production (MMcf)	1,593	1,857	(264)	(14.2)%	3,316	3,802	(486)	(12.8)%
Oil and liquids production (MBbl)	43	29	14	48.3%	90	58	32	55.2%
Total production (MMcfe)	1,849	2,033	(184)	(9.1)%	3,859	4,155	(296)	(7.1)%
Average daily production (Mcfe/d)	20,315	22,341	(2,026)	(9.1)%	21,322	22,830	(1,508)	(6.6)%

Total production (MBOE)	308	339	(31)	(9.1)%	643	692	(49)	(7.1)%
Average daily production (BOE/d)	3,386	3,720	(334)	(9.0)%	3,553	3,800	(247)	(6.5)%
Average sales prices:								
Natural gas price per Mcf with hedge settlements	$ 5.45	$ 6.03	$ (0.58)	(9.6)%	$ 5.59	$ 5.77	$ (0.18)	(3.1)%
Natural gas price per Mcf without hedge settlements	$ 3.73	$ 2.09	$ 1.64	78.5%	$ 3.40	$ 2.28	$ 1.12	49.1%
Oil and liquids price per Bbl with hedge settlements	$ 102.32	$ 100.00	$ 2.32	2.3%	$ 98.24	$ 106.55	$ (8.31)	(7.8)%
Oil and liquids price per Bbl without hedge settlements	$ 94.22	$ 98.83	$ (4.61)	(4.7)%	$ 92.63	$ 104.43	$ (11.80)	(11.3)%

	For the Three Months Ended				For the Six Months Ended			
	(Dollars in 000 s)							
	June 30, 2013	June 30, 2012	Variance $	Variance %	June 30, 2013	June 30, 2012	Variance $	Variance %
Total price per Mcfe with hedge settlements	$ 7.05	$ 6.93	$ 0.12	1.7%	$ 7.11	$ 6.76	$ 0.35	5.2%
Total price per Mcfe without hedge settlements	$ 5.39	$ 3.32	$ 2.07	62.3%	$ 5.09	$ 3.54	$ 1.55	43.8%
Total price per BOE with hedge settlements	$ 42.33	$ 41.64	$ 0.69	1.7%	$ 42.65	$ 40.64	$ 2.01	4.9%
Total price per BOE without hedge settlements	$ 32.34	$ 19.96	$ 12.38	62.0%	$ 30.55	$ 21.28	$ 9.27	43.6%
Average unit costs per Mcfe:								
Field operating expenses[(a)]	$ 2.45	$ 2.47	$ (0.02)	(0.8)%	$ 2.40	$ 2.56	$ (0.16)	(6.3)%
Lease operating expenses	$ 2.11	$ 2.31	$ (0.20)	(8.6)%	$ 2.11	$ 2.37	$ (0.26)	(11.0)%
Production taxes	$ 0.34	$ 0.18	$ 0.16	88.9%	$ 0.29	$ 0.18	$ 0.11	61.1%
General and administrative	$ 2.02	$ 1.82	$ 0.20	11.0%	$ 2.11	$ 1.81	$ 0.30	16.6%
General and administrative w/o unit-based compensation	$ 1.91	$ 1.64	$ 0.27	16.5%	$ 1.95	$ 1.66	$ 0.29	17.5%
Depreciation, depletion and amortization	$ 2.58	$ 1.14	$ 1.44	126.3%	$ 2.48	$ 1.13	$ 1.35	119.5%
Average unit costs per BOE:								
Field operating expenses[(a)]	$ 14.69	$ 14.92	$ (0.23)	(1.5)%	$ 14.38	$ 15.36	$ (0.98)	(6.4)%
Lease operating expenses	$ 12.67	$ 13.85	$ (1.18)	(8.5)%	$ 12.66	$ 14.25	$ (1.59)	(11.2)%
Production taxes	$ 2.02	$ 1.08	$ 0.94	87.0%	$ 1.72	$ 1.11	$ 0.61	55.0%
General and administrative	$ 12.13	$ 10.95	$ 1.18	10.8%	$ 12.66	$ 10.90	$ 1.76	16.1%
General and administrative w/o unit-based compensation	$ 11.45	$ 9.84	$ 1.61	16.4%	$ 11.72	$ 9.96	$ 1.76	17.7%
Depreciation, depletion and amortization	$ 15.47	$ 6.85	$ 8.62	125.8%	$ 14.87	$ 6.80	$ 8.07	118.7%

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes.

Three months ended June 30, 2013 compared to three months ended June 30, 2012

Oil and natural gas sales. Oil and liquid sales unhedged increased $1.1 million, or 40.4%, to $4.0 million for the three months ended June 30, 2013 as compared to $2.9 million for the same period in 2012. Natural gas sales unhedged increased $2.0 million, or 62.8%, to $5.2 million for the three months ended June 30, 2013 as compared to $3.2 million for the same period in 2012. With hedges and mark-to-market activities, our total revenue increased $6.2 million when compared to the same period in 2012. Of this increase, $3.8 million was attributable to higher market prices for our natural gas production and higher market prices for our oil production, $7.3 million in higher mark-to-market activities offset by $4.3 million attributable to lower cash hedge settlements from our hedge program, and $0.6 million attributable to decreased natural gas production volumes offset by higher oil volumes. Production for the three months ended June 30, 2013 was 1.8 Bcfe, which was 0.2 Bcfe lower than the same period in 2012. This decrease was associated with natural declines in our natural gas production in the Cherokee Basin not being fully offset by increases in our oil production. The production from our Woodford Shale properties remained level. Due to the decrease in the level of our drilling activities since 2010, our maintenance drilling programs have not been sufficient to offset the natural decline rate of production associated with our wells owned as of June 30, 2013. We hedged all of our actual consolidated production volumes sold through June 30, 2013, and approximately 75% of our actual production through June 30, 2012. In March 2013, we liquidated or repositioned certain of our hedges to ensure that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods.

Cash hedge settlements received for our commodity derivatives were approximately $3.1 million for the three months ended June 30, 2013. Cash hedge settlements received for our commodity derivatives were approximately $7.3 million for the three months ended June 30, 2012. This difference is due to changes in hedge prices, hedged volumes, and market prices for natural gas and oil during 2012.

As discussed below, our unrealized non-cash mark-to-market activities increased by $7.2 million for the three months ended June 30, 2013, as compared to the same period in 2012. Our realized prices before our hedging program increased from 2012 to 2013 primarily due to net higher market prices for our natural gas production. This was offset by our hedging program and the mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. All of our derivatives are accounted for as mark-to-market activities. For the three months ended June 30, 2013, the unrealized non-cash mark-to-market gain was approximately $2.3 million as compared to an unrealized non-cash mark-to-market loss of $4.9 million for the same period in 2012. The 2013 non-cash gain represents approximately $2.4 million from the impact of lower future expected oil and natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities and a $0.1 million loss related to non-performance risk associated with our counterparties. The 2012 non-cash loss represented approximately $5.1 million from the impact of future expected oil and natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities, offset by $0.2 million related to non-performance risk associated with our counterparties.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicle, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

For the three months ended June 30, 2013, lease operating expenses decreased $0.8 million, or 16.7%, to $3.9 million, compared to expenses of $4.7 million for the same period in 2012. This decrease in lease operating expenses is primarily related to $0.8 million in lower expenses in the Cherokee Basin. By category, our lease operating expenses were lower in 2013 as compared to 2012 by $0.8 million because of decreases of $0.4 million in elective costs such as well servicing and repairs and maintenance, $0.3 million in lower insurance and $0.1 million in lower ad valorem taxes.

For the three months ended June 30, 2013, per unit lease operating expenses were $2.11 per Mcfe compared to $2.31 per Mcfe for the same period in 2012.

For the three months ended June 30, 2013, production taxes increased $0.2 million, or 70.4%, to $0.6 million, compared to expenses of $0.4 million for the same period in 2012. This increase is primarily the result of higher market prices for natural gas and oil in 2013 offset by the impact of production taxes on 0.2 Bcfe in lower production in 2013.

Cost of sales. For the three months ended June 30, 2013, cost of sales remained flat compared to the same period in 2012.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations. General and administrative expenses remained flat at $3.7 million for the three months ended June 30, 2013, as compared to $3.7 million for the same period in 2012. Without severance costs of $0.2 million incurred during the three months ended June 30, 2013, our total reported general and administrative expenses for the three months ended June 30, 2013, would have been lower by approximately $0.2 million as compared to the same period in 2012.

Our per unit costs were $2.01 per Mcfe for the three months ended June 30, 2013, as compared to $1.82 per Mcfe for the same period in 2012. This increase is attributable to the impact of 0.2 Bcfe in lower production.

Gain on sale of asset. Our gain on the sale of assets increased approximately $0.01 million, or 325.0%, to a gain of less than $0.02 million for the three months ended June 30, 2013, as compared to a gain of less than $0.01 million for the same period in 2012. In 2013, we sold trucks and surplus equipment in Oklahoma at a gain of less than $0.02 million. In 2012, we sold trucks and surplus equipment at a gain of less than $0.01 million.

Depreciation, depletion and amortization expense and Asset Impairments. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming everything else remains unchanged, as oil or natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the three months ended June 30, 2013 was $4.8 million, or $2.58 per Mcfe, compared to $2.3 million, or $1.14 per Mcfe, for the same period in 2012. This increase in 2013 depreciation, depletion, and amortization reflects the decrease in our reserve base at December 31, 2012, primarily due to the impact of a lower SEC-required natural gas price used to calculate our reserves which resulted in negative reserve revisions, and increased expenditures incurred for our drilling programs in 2012. These revisions were partially offset by increased oil reserves as a result of our successful drilling programs and a 0.2 Bcfe decrease in production volumes during 2013 as compared to 2012. Our other assets are depreciated using the straight-line basis. Consistent with our prior practice, we will use our 2012 reserve report to calculate our depletion rate during the first three quarters of 2013 and will use our 2013 reserve report to record our depletion in the fourth quarter of 2013.

For the three months ended June 30, 2013 and June 30, 2012, no asset impairment was recorded.

Interest expense. Interest expense for the three months ended June 30, 2013 decreased $0.6 million, or 40.0%, to $0.9 million as compared to $1.5 million in interest expense for the same period in 2012. This decrease was primarily due to $0.5 million in higher non-cash mark-to-market gains on our interest rate swaps that are accounted for as mark-to-market activities, lower market interest expense on our outstanding debt of $0.3 million, and higher interest rate swap settlements of $0.2 million, while capitalized interest remained flat in 2013 to the same period in 2012. At June 30, 2013, we had an outstanding balance under our reserve-based credit facility of $34.0 million as compared to $88.4 million at June 30, 2012. The average interest rate on our outstanding debt was approximately 3.192% at June 30, 2013 compared to 6.0% during the same period in 2012.

Interest income. Interest income for the three months ended June 30, 2013, was less than $0.01 million as compared to less than $0.01 million for the same period in 2012. During 2013, market rates for overnight investments continued to be at historical lows, resulting in no significant earnings on our cash balances.

Six months ended June 30, 2013 compared to six months ended June 30, 2012

Oil and natural gas sales. Oil and liquid sales unhedged increased $2.3 million, or 38.3%, to $8.4 million for the six months ended June 30, 2013 as compared to $6.1 million for the same period in 2012. Natural gas sales unhedged increased $2.6 million, or 36.5%, to $9.6 million for the six months ended June 30, 2013 as compared to $7.0 million for the same period in 2012. With hedges and mark-to-market activities, our total revenue decreased $9.3 million when compared to the same period in 2012. Of this decrease, $8.6 million in lower mark-to-market activities, $5.6 million attributable to lower cash hedge settlements from our hedge program, and $1.0 million attributable to decreased natural gas production volumes offset by $6.0 million was attributable to higher market prices for our natural gas production and higher market prices for our oil production and by higher oil volumes. Production for the six months ended June 30, 2013 was 3.9 Bcfe, which was 0.3 Bcfe lower than the same period in 2012. This decrease was associated with natural declines in our natural gas production in the Cherokee Basin not being fully offset by increases in our oil production. The production from our Woodford Shale properties remained level. Due to the decrease in the level of our drilling activities since 2010, our maintenance drilling programs have not been sufficient to offset the natural decline rate of production associated with our wells owned as of June 30, 2013. We hedged all of our actual consolidated production volumes sold through June 30, 2013, and approximately 74% of our actual production through June 30, 2012. In March 2013, we liquidated or repositioned certain of our hedges to ensure that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods.

Cash hedge settlements received for our commodity derivatives were approximately $7.8 million for the six months ended June 30, 2013. Cash hedge settlements received for our commodity derivatives were approximately $13.4 million for the six months ended June 30, 2012. This difference is due to changes in hedge prices, hedged volumes, and market prices for natural gas and oil during 2012.

As discussed below, our unrealized non-cash mark-to-market activities decreased by $8.6 million for the six months ended June 30, 2013, as compared to the same period in 2012. Our realized prices before our hedging program increased from 2012 to 2013 primarily due to net higher market prices for our natural gas production. This was offset by our hedging program and the mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. All of our derivatives are accounted for as mark-to-market activities. For the six months ended June 30, 2013, the unrealized non-cash mark-to-market loss was approximately $6.9 million as compared to an unrealized non-cash mark-to-market gain of $1.7 million for the same period in 2012. These losses represent the change in the estimated fair value of our open derivative positions for each period. The 2013 non-cash loss represents approximately $6.8 million from the impact of higher future expected oil and natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities and a $0.1 million loss related to non-performance risk associated with our counterparties. The 2012 non-cash gain represented approximately $2.2 million from the impact of lower than expected future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities offset by a $0.5 million reduction for non-performance risk related to our counterparties.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicle, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

For the six months ended June 30, 2013, lease operating expenses decreased $1.7 million, or 17.4%, to $8.2 million, compared to expenses of $9.9 million for the same period in 2012. This decrease in lease operating expenses is primarily related to $1.7 million in lower expenses in the Cherokee Basin. Our lease operating expenses were lower in 2013 as compared to 2012 by $1.7 million because of decreases of $1.0 million in elective costs such as well servicing and repairs and maintenance, $0.5 million in lower insurance, and $0.2 million in lower ad valorem taxes.

For the six months ended June 30, 2013, per unit lease operating expenses were $2.11 per Mcfe compared to $2.37 per Mcfe for the same period in 2012.

For the six months ended June 30, 2013, production taxes increased $0.3 million, or 44.6%, to $1.1 million, compared to expenses of $0.8 million for the same period in 2012. This increase is primarily the result of higher market prices for natural gas and oil in 2013 offset by the impact of production taxes on 0.3 Bcfe in lower production in 2013.

Cost of sales. For the six months ended June 30, 2013, cost of sales increased by $0.2 million, or 25.6%, to $0.8 million, compared to $0.6 million for the same period in 2012. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower production volumes and lower market prices for natural gas in 2012, as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations. General and administrative expenses increased $0.6 million, or 8.0%, to $8.1 million for the six months ended June 30, 2013, as compared to $7.5 million for the same period in 2012. Our general and administrative expenses were higher in 2013 as compared to 2012 because of $1.0 million in severance costs, $0.4 million in higher labor and incentive compensation costs, offset by $0.8 million in lower professional services and consulting costs including the costs associated with the termination of our support services agreement for revenue accounting services. Without the severance costs, our total reported general and administrative expenses for the six months ended June 30, 2013, would have been lower by approximately $0.2 million as compared to the same period in 2012.

Our per unit costs were $2.11 per Mcfe for the six months ended June 30, 2013, as compared to $1.81 per Mcfe for the same period in 2012. This increase is attributable to the impact of 0.3 Bcfe in lower production and by an increase in total spending of approximately $0.6 million. Excluding the impact of the severance costs, our total per unit costs excluding non-cash unit-based compensation expenses would have been $1.89 per Mcfe in 2013.

Gain on sale of asset. Our gain on the sale of assets increased approximately $0.02 million to a gain of less than $0.02 million for the six months ended June 30, 2013, as compared to none for the same period in 2012. In 2013, we sold trucks and surplus equipment in Oklahoma at a gain of approximately $0.02 million.

Depreciation, depletion and amortization expense and Asset Impairments. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming everything else remains unchanged, as oil or natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the six months ended June 30, 2013 was $9.6 million, or $2.48 per Mcfe, compared to $4.7 million, or $1.13 per Mcfe, for the same period in 2012. This increase in 2013 depreciation, depletion, and amortization reflects the decrease in our reserve base at December 31, 2012, primarily due to the impact of a lower SEC-required natural gas price used to calculate our reserves which resulted in negative reserve revisions, and increased expenditures incurred for our drilling programs in 2012. These revisions were partially offset by increased oil reserves as a result of our successful drilling programs and a 0.3 Bcfe decrease in production volumes during 2013 as compared to 2012. Our other assets are depreciated using the straight-line basis. Consistent with our prior practice, we will use our 2012 reserve report to calculate our depletion rate during the first three quarters of 2013 and will use our 2013 reserve report to record our depletion in the fourth quarter of 2013.

For the six months ended June 30, 2013, no asset impairment was recorded, compared to asset impairments of $0.1 million for the same period in 2012. Our non-cash impairment charges in 2012 were approximately $0.1 million to impair certain of our wells in the Woodford Shale. This impairment was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in a third party reserve report. The impairment was primarily caused by the impact of lower future natural gas prices during the first quarter of 2012 on future expected cash flows.

Interest expense. Interest expense for the six months ended June 30, 2013 decreased $0.8 million, or 27.5%, to $2.2 million as compared to $3.0 million in interest expense for the same period in 2012. This decrease was primarily due to $3.0 million in higher non-cash mark-to-market gains on our interest rate swaps that are accounted for as mark-to-market activities, lower market interest expense of $0.3 million and higher interest rate swap settlements of $2.4 million, while capitalized interest remained flat in 2013 to the same period in 2012. At June 30, 2013, we had an outstanding balance under our reserve-based credit facility of $34.0 million as compared to $88.4 million at June 30, 2012. The average interest rate on our outstanding debt was approximately 3.192% as of June 30, 2013 compared to 6.0% in 2012. We have used interest rate swaps to reduce our exposure to changes in the LIBOR rate. In March 2013, we reduced our outstanding interest rate swaps that fix our LIBOR rate through 2014 to $30 million, which increased our interest rate swap settlements by $2.1 million. This position was closed in May 2013 resulting in an offsetting non-cash gain in our mark-to-market interest swap activities. We accelerated the amortization of approximately $0.7 million in debt issue costs in 2013 as a result of the second amendment of our reserve-based credit facility which set our borrowing base at $55.0 million effective with the sale of the Robinson s Bend Field assets.

Interest income. Interest income for the six months ended June 30, 2013, was less than $0.01 million as compared to less than $0.01 million for the same period in 2012. During 2013, market rates for overnight investments continued to be at historical lows, resulting in no significant earnings on our cash balances.

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Discontinued Operations. A loss from discontinued operations for the six months ended June 30, 2013 increased $0.6 million, or 26.0%, to a loss of $2.7 million as compared to a loss of $2.1 million in discontinued operations for the same period in 2012. Our discontinued operations represent the net loss associated with the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama, in a transaction that closed on February 28, 2013, with an effective date of December 1, 2012. The loss in 2013 reflects a $3.1 million loss on the sale of the properties, only two months of income and lower depreciation expenses.

Liquidity and Capital Resources

During 2012 and through August 14, 2013, we utilized our cash flow from operations as our primary source of capital to fund our operating and capital programs. Our primary use of capital during this time was for the development of existing oil opportunities within our asset base in the Cherokee Basin. On February 28, 2013, we also sold our Robinson s Bend Field assets in the Black Warrior Basin of Alabama and used $50.0 million of the proceeds from that sale to reduce our outstanding debt. On August 9, 2013 we acquired oil, natural gas and natural gas liquids assets in Texas and Louisiana from SEP I for a purchase price of $30.4 million. The cash portion of the transaction was financed with cash on hand and a borrowing of $16.7 million under CEP s reserve-based credit facility.

Based upon our current business plan for 2013, we anticipate that we will continue to generate sufficient operating cash flows to meet our working capital needs and fund a planned capital expenditure program between $19.0 million and $21.0 million. We will be monitoring the capital resources available to us to meet our future financial obligations and our planned 2013 capital expenditures. Our current expectation is that we will continue managing our business to operate within the cash flows that are generated.

Given our focus on debt reduction since June 2009, our quarterly distributions to our unitholders remained suspended through the second quarter of 2013. At June 30, 2013, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business and the payment of fees and expenses) from which to pay distributions.

Our future success in growing reserves and production will be highly dependent on the capital resources available to us and our success in drilling for or acquiring additional reserves and managing the costs associated with our operations. We routinely monitor and adjust our capital expenditures and operating expenses in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, and internally generated cash flow. Based upon current oil and natural gas price expectations, our existing hedge position and expected production levels in 2013, we anticipate that our cash flow from operations can meet our planned capital expenditures and other cash requirements for the next twelve months without increasing our debt. If needed, we may issue additional equity securities to raise additional capital. Future cash flows and our borrowing capacity are subject to a number of variables, including the level of oil and natural gas production, the market prices for those products and our hedge position. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our reduced debt level, planned levels of capital expenditures, operating expenses, or any cash distributions that we may make to unitholders.

Sources of Debt and Equity Financing

In May 2013, we amended our existing reserve-based credit facility. This amendment increased our borrowing capacity, extended the maturity date and changed the lenders participating in the facility.

As of August 14, 2013, the borrowing base under our reserve-based credit facility was $55.0 million and we had $50.7 million of debt outstanding under the facility, leaving us with $4.3 million in unused borrowing capacity. Our reserve-based credit facility matures on May 30, 2017.

In 2011, we filed a shelf registration statement with the SEC to register up to $500 million of debt or equity securities to repay or refinance outstanding debt and to fund working capital, capital expenditures and any acquisitions. This registration statement will expire in February 2014. As a smaller reporting company, any sales of securities under our shelf registration statement during the preceding rolling 12 months is limited to one-third of our public float. Our public float is calculated by multiplying the highest closing price of our Class B common units within the last 60 days by the number of outstanding Class B common units held by non-affiliates. There is no guarantee that securities can or will be issued under the registration statement or that conditions in the financial markets would be supportive of an issuance of such securities by us. If needed, we may also issue securities in one or more private placements.

Cash Flow from Operations

Our net cash flow provided by operating activities for the six months ended June 30, 2013 was $6.0 million, compared to net cash flow provided by operating activities of $5.4 million for the same period in 2012. This $0.6 million increase in operating cash flow is attributable to the impact of $0.8 million from higher cash operating expenses, $0.2 million in lower cash flow from discontinued operations, and changes in working capital.

The increase in oil and natural gas sales is a result of $6.0 million from higher market prices for natural gas and oil, offset by $5.6 million as a result of lower cash settlements of our oil and natural gas hedges and $1.1 million from lower natural gas production volumes offset by higher oil production volumes. The lower cash operating expenses is primarily as a result of lower total spending for lease operating expenses offset by the impact of higher production taxes and higher cost of sales. The remaining net change in working capital and other items is primarily the result of the timing of payments and collection of accounts receivable.

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The change in our working capital from 2013 to 2012 was attributable to higher other assets of $1.1 million, lower accrued liabilities of $1.4 million, and higher prepaid expenses of $0.1 million, offset by higher accounts receivable of $1.2 million and increased other liabilities of $1.1 million. Our accrued liabilities decreased after the payments associated with our 2012 incentive compensation programs were made, offset by an increase in severance payments not yet made. Our accounts payable decreased due to timing of invoice payments and lower checks-in-transit in 2013. Our receivables balance decreased as we collected additional oil sales from certain tank batteries and our royalty payable balance decreased due to both lower production volumes for our estimated oil and natural gas sales and royalty payments made on oil sales. The increase in other assets is related to the establishment of an escrow account of approximately $1.2 million related to certain closing conditions associated with the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama. These funds will be held in escrow for up to twenty-four months. Our discontinued operations had an effective date of the sale of December 1, 2012 and a closing date of February 28, 2013.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of market prices for oil and natural gas, our hedging program and our level of production of oil and natural gas. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program or completing acquisitions and successfully executing our hedging program. For additional information on our business plan, refer to Outlook .

Open Commodity Hedge Position

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also impacted by the cost of oilfield services. In the event of inflation increasing service costs or administrative expenses, our hedging program will limit our ability to have increased operating cash flows to fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender in our reserve-based credit facility and we do not currently post collateral with our counterparties under any of these agreements. This is significant since we are able to lock in sales prices on a substantial amount of our expected future production without posting cash collateral based on price changes prior to the hedges being cash settled.

For 2013, we now forecast our total net natural gas production to range between 7.1 Bcf and 7.9 Bcfe and our total net oil production of between 220,000 Bbls and 250,000 Bbls. This forecast includes the contribution anticipated from the assets we acquired from SEP I in a transaction that closed in August 2013. For the remainder of 2013, the company has hedged approximately 3.4 Bcfe of its natural gas production at an effective NYMEX fixed price of $6.17 per Mcfe with Mid-Continent basis hedges on 2.5 Bcfe of this amount at an average differential of $0.39 per Mcfe. The company also has hedges in place on approximately 91 MBbl of its oil production at a fixed price of $97.88 per barrel. These hedge positions lock in a significant portion of our expected revenues for 2013, although we are still exposed to increases or decreases in oil and natural gas prices on any of our unhedged volumes.

The following tables summarize, for the periods indicated, our hedges currently in place through December 31, 2016. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps NYMEX (Henry Hub)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2013					1,721,278	$ 6.17	1,691,540	$ 6.18	3,412,818	$ 6.18
2014	1,575,000	$ 5.75	1,592,500	$ 5.75	1,610,000	$ 5.75	1,610,000	$ 5.75	6,387,500	$ 5.75
2015	1,011,055	$ 4.27	971,604	$ 4.27	938,968	$ 4.27	908,492	$ 4.27	3,830,119	$ 4.27
2016	441,492	$ 4.31	426,825	$ 4.31	414,329	$ 4.31	403,684	$ 4.31	1,686,330	$ 4.31

	15,316,767

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MTM Fixed Price Basis Swaps CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), or Southern Star Central Gas Pipeline (Texas, Oklahoma, and Kansas)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2013					1,273,525	$ 0.39	1,223,985	$ 0.39	2,497,510	$ 0.39
2014	1,178,422	$ 0.39	1,133,022	$ 0.39	1,084,270	$ 0.39	1,047,963	$ 0.39	4,443,677	$ 0.39
									6,941,187	

MTM Fixed Price Basis Swaps West Texas Intermediate (WTI)

	For the quarter ended (in Bbls)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2013					44,490	$ 97.60	46,079	$ 98.15	90,569	$ 97.88
2014	43,353	$ 94.04	40,991	$ 94.10	38,874	$ 94.18	36,811	$ 94.30	160,029	$ 94.15
2015	23,919	$ 93.37	22,494	$ 93.48	21,237	$ 93.58	20,030	$ 93.70	87,680	$ 93.53
2016	17,957	$ 85.50	16,985	$ 85.50	16,048	$ 85.50	15,127	$ 85.50	66,117	$ 85.50
									404,395	

Investing Activities Acquisitions and Capital Expenditures

Cash provided by investing activities was $52.6 million for the six months ended June 30, 2013, compared to cash used in investing activities of $5.3 million for the same period in 2012. Our cash capital expenditures were $6.4 million in 2013, which consisted of $6.3 million in development expenditures in the Cherokee Basin and $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin. We have completed 26 net wells and 13 net recompletions during the first six months of 2013 and have 5 net wells and net recompletions in progress at June 30, 2013. We also sold our Robinson s Bend Field assets in the Black Warrior Basin of Alabama for net proceeds of approximately $58.9 million after customary costs and working capital adjustments and received less than $0.1 million in distributions from an equity affiliate. We do not currently expect the sale of our natural gas assets in the Black Warrior Basin of Alabama to significantly reduce our future net cash flows in 2013, as we have significantly reduced our outstanding debt level which will lower our cash interest payments.

Our cash capital expenditures were $6.8 million for the six months ended June 30, 2012, which primarily consisted of development expenditures in the Cherokee Basin. We completed 21 net wells and 27 net recompletions during the first six months of 2012 and had 24 net wells and net recompletions in progress. We also sold 14 wells in the Central Kansas Uplift for $1.4 million and $0.1 million in trucks and equipment during the first half of 2012 and received approximately $0.1 million in distributions from an equity affiliate.

Our current 2013 capital budget of $19.0 million to $21.0 million remains unchanged and is expected to be funded using our cash flow from operations and by using the remaining net proceeds from the sale of our natural gas assets in the Black Warrior Basin. We currently expect to focus our entire 2013 capital budget on higher return oil opportunities and capital efficient recompletion opportunities in our existing asset base in the Cherokee Basin. We currently believe that opportunity set is sufficient to warrant a continuing focus on our oil opportunities in the Cherokee Basin with investment of free cash flow at rates of return exceeding 20% over the next few years.

The amount and timing of our capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline to levels below acceptable levels, drilling costs escalate, or our efforts to exploit oil potential in our asset base prove to be unsuccessful, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, and internally generated cash flow. These and other matters are outside of our control and could affect the timing of our capital expenditures. Based upon current oil and natural gas price expectations and expected 2013 production levels, we anticipate that our cash flow from operations will meet any planned capital expenditures and other cash requirements for the next twelve months. We also have access to any existing available borrowing capacity under our reserve-based credit facility and our then existing cash balance if additional funds are needed in the future. Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that our operations and other capital resources will provide cash in sufficient amounts during 2013 to maintain our planned levels of capital expenditures, to maintain the outstanding debt level under our reserve-based credit facility, or to commence any quarterly distribution to unitholders. Our capital expenditures are also impacted by drilling and service costs. In the event of inflation increasing drilling and service costs, our hedging program will limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending.

Financing Activities

Our net cash used by financing activities was $51.0 million for the six months ended June 30, 2013, compared to $10.2 million used by financing activities for the same period in 2012. In 2013, we borrowed $0.2 million in short-term borrowings under our reserve-based credit facility for working capital purposes. During the first six months of 2013, we used $50.2 million to reduce our outstanding debt level to $34.0 million. This debt reduction was funded from the proceeds from the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama. We also used $0.2 million to fund the cost of units tendered by employees for tax withholdings for unit-based compensation. At June 30, 2013, we had approximately $0.8 million in debt issue costs remaining to be amortized over the life our reserve-based credit facility.

We suspended our $0.13 per unit quarterly distributions to unitholders for the quarter ended June 30, 2009, through the quarter ended June 30, 2013, to reduce our outstanding indebtedness.

Our net cash used by financing activities was $10.2 million for the six months ended June 30, 2012. We used $0.2 million to fund the cost of units tendered by employees for tax withholdings for unit-based compensation and had approximately $1.8 million in debt issue costs remaining to be amortized at June 30, 2012.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements with third parties, and we maintain no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through August 14, 2013, we have not suffered any significant losses with our counterparties as a result of nonperformance.

Certain key counterparty relationships are described below:

Macquarie Energy LLC

Macquarie Energy LLC (Macquarie), a subsidiary of Sydney, Australia-based Macquarie Group Limited, purchases a portion of our natural gas production in the Cherokee Basin. We have received a guarantee from Macquarie Bank Limited for up to $4.0 million in purchases through December 31, 2013. As of August 14, 2013, we have no past due receivables from Macquarie.

Scissortail Energy, LLC

Scissortail Energy, LLC (Scissortail), a subsidiary of Copano Energy, L.L.C., purchases a portion of our natural gas production in Oklahoma and Kansas. As of August 14, 2013, we have no past due receivables from Scissortail.

ONEOK Energy Services Company, L.P.

ONEOK Energy Services Company, L.P. (ONEOK), a subsidiary of ONEOK, Inc., purchases a portion of our natural gas production in Oklahoma and Kansas. We have received a guarantee from ONEOK, Inc. for up to $3.0 million in purchases through November 30, 2013. As of August 14, 2013, we have no past due receivables from ONEOK.

Derivative Counterparties

As of August 14, 2013, all of our derivatives are with Societe Generale and The Bank of Nova Scotia. All of our derivatives are currently collateralized by the assets securing our reserve-based credit facility and therefore currently do not require the posting of cash collateral. As of August 14, 2013, each of these financial institutions has an investment grade credit rating.

Reserve-Based Credit Facility

As of August 14, 2013, the banks and their percentage commitments in our reserve-based credit facility are: Societe Generale (36.36%), OneWest Bank, FSB (36.36%), and BOKF NA, dba Bank of Oklahoma (27.28%). As of August 14, 2013, each of these financial institutions has an investment grade credit rating.

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Outlook

During 2013, we expect that our business will continue to be affected by the factors described in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2012, as well as the following key industry and economic trends. Our expectation is based upon key assumptions and information currently available to us. To the extent that our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Full Year 2013 Expected Results

Our 2013 business plan and forecast is focused on prioritizing oil production in the execution of our capital program, actively managing our operating expenses and actively pursuing merger and acquisition opportunities. We currently expect our operating environment to be characterized by continued low natural gas prices, stable oil prices and the pressure to reduce operating expenses.

For 2013, we currently anticipate:

- Our production to be at or slightly below 8.9 Bcfe and we are significantly hedged at prices that are attractive relative to the price levels we currently observe in the commodity markets.
- Our operating expenses to be actively managed, resulting in a range of $32.5 million to $35.3 million.
- Our Adjusted EBITDA to be in a range of $27.5 million to $29.5 million.
- Our total capital expenditures to be between $19.0 million to $21.0 million.
- We have implemented strategies to lower operating costs, with a goal of reducing our structural general and administrative costs by the end of 2013. We expect our general and administrative expenses to have a run rate of $12.4 million in 2013, with opportunities available to save another $0.6 million in 2014.
- At the present time, we are actively pursuing merger and acquisition opportunities.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions. The results of these estimates and assumptions form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements.

As of June 30, 2013, there were no changes with regard to the critical accounting policies disclosed in our Annual Report on Form 10-K for the year ended December 31, 2012, which was filed on March 11, 2013. The policies disclosed included the accounting for oil and natural gas properties, oil and natural gas reserve quantities, revenue recognition and hedging activities. Please read Note 1 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2013, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. We are currently reviewing the recently issued standards and interpretations but none are expected to have a material impact on our financial statements.

New Accounting Pronouncements

See Note 1 to our condensed consolidated financial statements included in this report for information on new accounting pronouncements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators about how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Global Financial and Energy Markets

The U.S. economy continues to show steady signs of improvement, but the level of improvement has been insufficient to materially increase the demand for natural gas, which accounts for a majority of our production. Concurrently, production from shale gas plays has increased the supply of natural gas, inventories of natural gas in storage remain at record high levels, and mild winter and spring weather has impacted the demand for natural gas. As a result, future expected prices for natural gas remain depressed relative to the price levels observed at the time our assets were acquired. At the same time, oil prices have remained at a relatively high level due to strong demand for crude oil products and tensions in the Middle East. As a result, we have hedged a significant portion of our expected natural gas and oil production from 2013 through 2016. We have also shifted all of our capital expenditures to focus on oil drilling and recompletion opportunities in the Cherokee Basin to increase the percentage of our production and sales revenue from higher value added oil production.

Through August 14, 2013, we have reduced our outstanding debt from a high of $220.0 million in 2009 to $50.7 million. This reduction in debt was achieved through a combination of the sale of our natural gas assets in the Black Warrior Basin of Alabama in 2013, the one-time restructuring of our NYMEX fixed-for-floating price swaps in 2011, the suspension of our cash distribution since 2009, the reduction of our capital expenditures since 2009, significant reductions in our operating expenses and the dedication of a significant portion of our operating cash flows to reducing debt. Although we are a smaller company after this effort, we expect that our ability to issue debt and equity securities may improve over the next year. In May 2013, we entered into a new reserve-based credit facility with a higher borrowing base and an extended term. However, our ability to issue debt or equity securities may still be impacted, particularly if future expected market prices for natural gas remain depressed or decline further or in the event of further reductions in credit availability by financial institutions due to stress in the financial markets, including as a result of the debt crisis in Europe or fiscal issues in the United States. We continue to monitor the financial and energy markets to determine if we need to further adjust our business plans in response to changes in market conditions.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the NYMEX (Henry Hub) and Inside FERC prices for CenterPoint Energy Gas Transmission (East), Natural Gas Pipeline Company of America (Midcontinent), the CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipe Line (Texas, Oklahoma) and Southern Star Central Gas Pipeline (Texas, Oklahoma, Kansas) with respect to our natural gas properties in the Cherokee Basin, the Inside FERC price for the CenterPoint Energy Gas Transmission (East) for our natural gas properties in the Woodford Shale, NYMEX West Texas Intermediate (Cushing, Oklahoma) for our oil production and the spot market prices applicable to all of our oil production and the spot market prices applicable to all of oil and natural gas production. Historically, pricing for oil and natural gas has been volatile and unpredictable and we expect this volatility to continue in the future. We are currently operating in an environment characterized by low natural gas prices which tends to lower the revenues that we realize on our unhedged natural gas production and limit the amount of operating cash flows. The prices we receive for oil and natural gas production depend on many factors outside our control, including weather, economic conditions, and the total supply of oil and natural gas available for sale in the market.

We have entered into hedging arrangements with respect to a portion of our projected future production through various derivatives that hedge the future prices received. These hedging activities are intended to support commodity sales prices at targeted levels and to manage our exposure to commodity price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes. The use of hedging transactions also involves the risk that one or more of the counterparties will be unable to meet the financial terms of the transactions executed. We attempt to minimize this risk by entering into our derivative transactions with counterparties that are lenders, or affiliated with a lender, in our reserve-based credit facility. The table below presents the hypothetical changes in fair values arising from potential changes in the quoted market prices of the commodity underlying the derivative instruments used to mitigate these market risks. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the sale of the hedged production, which are not included in the table. These derivatives do not hedge all of our commodity price risk related to our forecasted sales of oil and natural gas production and, as a result, we are subject to commodity price risk on our remaining unhedged oil and natural gas production.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**(Decrease)**	**Fair Value**	**Increase**
			(in 000 s)		
Impact of changes in commodity prices on derivative commodity instruments at June 30, 2013	$ 20,944	$ 12,059	$ (8,885)	$ 29,829	$ 8,885

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Interest Rate Risk

At June 30, 2013, the one-month LIBOR rate was 0.20%, the three-month LIBOR rate was 0.27%, and our applicable margin on LIBOR borrowings was 3.00%. At June 30, 2013, the ABR rate was 3.25%, and our applicable margin on ABR borrowings was 2.00%. At June 30, 2013, we had debt outstanding of $34.0 million, all of which incurred interest at a one-month LIBOR rate plus an applicable margin of 3.00% based on utilization. We had no debt outstanding at the ABR rate. At June 30, 2013, the carrying value and fair value of our debt is $34.0 million.

We enter into hedging arrangements from time to time to reduce the impact of volatility stemming from changes in the LIBOR interest rate on our interest payments. At August 14, 2013, we had no interest rate derivatives.

The table below presents the hypothetical changes in fair values arising from potential changes in the quoted interest rate underlying the derivative instruments used to mitigate these market risks.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Increase	Fair Value	(Decrease)
			(in 000 s)		
Impact of changes in LIBOR on derivative interest rate instruments at June 30, 2013	$ 0	$ 0	$ 0	$ 0	$ 0

Item 4. Controls and Procedures

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, with CEP have been detected. These inherent limitations include error by personnel in executing controls due to faulty judgment or simple mistakes, which could occur in situations such as when personnel performing controls are new to a job function or when inadequate resources are applied to a process. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions or personnel, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and the Chief Financial Officer of CEP have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of June 30, 2013 (the Evaluation Date). Based on such evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and is accumulated and communicated to our management, including our Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

In January 2013, we terminated our support services agreement with Schlumberger, ePrime Services. Through this outsource agreement, Schlumberger managed the payable and receivable activities associated with our interests in oil and natural gas properties, including the payment of invoices, calculation and payment of royalties, and receipt of revenues from oil and natural gas sales, and provided accounting information used to generate financial statements. These functions are now handled by our internal accounting department in Houston, Texas, utilizing the same oil and gas computer software Schlumberger used. Additional experienced staffing has been hired, primarily in the revenue accounting and accounts payable functions.

During the three months ended June 30, 2013, there were no changes in CEP s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, CEP s internal control over financial reporting.

Part II Other Information

Item 1. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any other material legal proceedings other than those that have been previously disclosed. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under various environmental protection statutes or other regulations to which we are subject.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in Item 1A. to Part I of our Annual Report on Form 10-K for the year ended December 31, 2012 that was filed with the SEC on March 11, 2013. An investment in our Class B common units involves various risks. When considering an investment in us, careful consideration should be given to the risk factors described in our 2012 Form 10-K. These risks and uncertainties are not the only ones facing us and there may be additional matters that are not known to us or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition or future results and, thus, the value of an investment in us.

Tax Risks to Unitholders

Unitholders may be required to pay taxes on income from us, including their share of ordinary income and any capital gains on dispositions of properties by us, even if they do not receive any cash distributions from us.

Unitholders are required to pay U.S. federal income taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not they receive cash distributions from us. Generally, should we generate taxable income for a particular tax year and not pay any cash distributions, our unitholders will be required to pay the actual U.S. federal income tax liability that results from their share of such taxable income even though they received no cash distributions from us.

We have not paid any cash distributions on our units since June 2009. If we generate taxable income that is allocable to our unitholders for the 2013 tax year, unitholders who hold our common units during 2013 may not receive cash distributions from us sufficient to pay any actual tax liability that resulted from their share of any 2013 taxable income. Further, if we generate taxable income from either operations or the sale of assets in future years and do not distribute the resulting cash, our unitholders may not receive sufficient cash distributions to pay the actual tax liability that result from their allocable share of our taxable income. The majority of the proceeds generated in 2013 from the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama was used to pay down debt and will not result in sufficient distributions to unitholders to pay any actual tax liability of each unitholder attributable to such sale.

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Forward-Looking Statements

This Quarterly Report on Form 10-Q contains forward-looking statements as defined by the SEC that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

- the volatility of realized oil and natural gas prices;
- the conditions of the capital markets, inflation, interest rates, availability of a credit facility to support business requirements, liquidity, and general economic and political conditions;
- the discovery, estimation, development and replacement of oil and natural gas reserves;
- our business, financial, and operational strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity, working capital and financial position;
- the level of our borrowing base under our reserve-based credit facility and our ability to refinance the debt outstanding under such facility prior to its maturity date;
- the resumption or amount of our cash distributions;
- our hedging program and our derivative positions;
- our production volumes;
- our lease operating expenses, general and administrative costs and finding and development costs;
- the availability of drilling and production equipment, labor and other services;
- our future operating results;

our prospect development and property acquisitions;

the marketing of oil and natural gas;

competition in the oil and natural gas industry;

the impact of the current global credit and economic environment;

the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, tornados, earthquakes, snow and ice storms and other catastrophic events and natural disasters;

governmental regulation, including environmental regulation, and taxation of the oil and natural gas industry or publicly traded partnerships;

developments in oil-producing and natural gas producing countries;

lack of support from a sponsor;

our strategic plans, objectives, expectations, forecasts, budgets, estimates and intentions for future operations; and

our ability to integrate the assets acquired from Sanchez Energy Partners I, LP.

All of these types of statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 2. and other items within this Quarterly Report on Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as may, could, should, expect, plan, project, intend, anticipa estimate, predict, potential, pursue, target, continue, the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Quarterly Report on Form 10-Q are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors listed in the Risk Factors section and elsewhere in this Quarterly Report on Form 10-Q. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

(a) The following documents are filed as a part of this Quarterly Report on Form 10-Q:

1. Financial Statements:

Condensed Consolidated Balance Sheets Constellation Energy Partners LLC at June 30, 2013 and December 31, 2012

Condensed Consolidated Statements of Operations and Comprehensive Income/(Loss) Constellation Energy Partners LLC for the six months ended June 30, 2013 and June 30, 2012

Condensed Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the six months ended June 30, 2013 and June 30, 2012

Condensed Consolidated Statements of Changes in Members Equity Constellation Energy Partners LLC for the six months ended June 30, 2013

Notes to Condensed Consolidated Financial Statements

EXHIBIT INDEX

Exhibit Number	Description
2.1	Contribution Agreement, dated as of August 9, 2013, by and between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
3.1	Amendment No. 5 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of August 9, 2013 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
10.1	Second Amendment and Restated Credit Agreement dated as of May 30, 2013, among Constellation Energy Partners LLC, as borrower, Societe Generale, as administrator agent and collateral agent, and the lenders party hereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May

	31, 2013, File No. 001-33147).
10.2	Registration Rights Agreement, dated as of August 9, 2013, between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
*31.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Principal Financial Officer and Principal Accounting Officer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC 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 Principal Financial Officer and Principal Accounting Officer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XRBL Instance Document
**101.SCH	XRBL Schema Document
**101.CAL	XRBL Calculation Linkbase Document
**101.LAB	XRBL Label Linkbase Document
**101.PRE	XRBL Presentation Linkbase Document
**101.DEF	XRBL Label Linkbase Document

* Filed herewith

** Pursuant to Rule 406T of Regulation S-T, the interactive data files on Exhibit 101 hereto are not deemed filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act of 1933, as amended, are not deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under those actions.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, Constellation Energy Partners LLC, the Registrant, has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY PARTNERS LLC

(REGISTRANT)

Date: August 14, 2013

By /s/ Charles C. Ward
Charles C. Ward
Principal Financial Officer and Principal Accounting Officer