Constellation Energy Partners LLC
Form 10-Q
November 14, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013

OR

¨TRANSITION REPORT PURSUANT TO SECTIO7 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	11-3742489
(State of	(I.R.S. Employer

organization)	Identification No.)
1801 Main Street, Suite 1300	
Houston, Texas	77002
(Address of Principal Executive Offices)	(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 November 8, 2013: 28,463,746 units.

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 3,724	$ 1,959
Accounts receivable	6,784	5,615
Prepaid expenses	1,419	1,309
Risk management assets (see Note 5)	12,196	17,965
Current assets from discontinued operations	—	1,886
Total current assets	24,123	28,734
Oil and natural gas properties (See Note 6)		
Oil and natural gas properties, equipment and facilities	638,231	594,020
Material and supplies	846	771
Less accumulated depreciation, depletion, amortization, and impairments	(489,083)	(474,669)
Net oil and natural gas properties	149,994	120,122
Other assets		
Debt issue costs (net of accumulated amortization of $9,003 and $7,775, respectively)	865	1,168
Risk management assets (see Note 5)	4,404	7,431
Other non-current assets	4,109	3,194
Long-term assets from discontinued operations	—	67,373
Total assets	$ 183,495	$ 228,022
LIABILITIES AND MEMBERS' EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 46	$ 480
Accrued liabilities	8,357	7,174
Royalty payable	1,364	1,418
Risk management liabilities (see Note 5)	—	523
Debt	—	50,000
Current liabilities from discontinued operations	—	1,578

Total current liabilities		9,767		61,173
Other liabilities				
Asset retirement obligation		9,325		7,665
Risk management liabilities (see Note 5)		—		637
Other non-current liabilities		1,953		589
Debt		50,700		34,000
Other long-term liabilities from discontinued operations		—		7,692
Total liabilities		71,745		111,756
Commitments and contingencies (See Note 9)				
Members' equity				
Class A units, 1,615,017 and 483,418 units authorized, issued and outstanding, respectively		2,847		2,326
Class B units, 28,848,785 and 24,124,378 units authorized, respectively, and 28,463,746 and 23,687,507 issued and outstanding, respectively		108,903		113,940
Total members' equity		111,750		116,266
Total liabilities and members' equity	$	183,495	$	228,022

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

(In thousands, except per unit data)

(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Revenues				
Natural gas sales	$ 7,328	$ 1,898	$ 18,745	$ 23,243
Oil and liquids sales	4,803	1,379	13,874	9,847
Total revenues (see Note 5)	12,131	3,277	32,619	33,090
Expenses:				
Operating expenses:				
Lease operating expenses	5,191	4,869	13,332	14,727
Cost of sales	323	287	1,122	923
Production taxes	731	374	1,840	1,141
General and administrative	3,015	4,014	11,156	11,555
Loss on sale of assets	31	—	8	—
Depreciation, depletion, and amortization	5,491	2,373	15,056	7,078
Asset impairments	—	—	—	107
Accretion expense	163	116	409	345
Total operating expenses	14,945	12,033	42,923	35,876
Other expenses (income)				
Interest expense	420	1,534	2,636	4,590
Other expenses (income)	23	(21)	(149)	(114)
Total other expenses	443	1,513	2,487	4,476
Total expenses	15,388	13,546	45,410	40,352
Loss from continuing operations	(3,257)	(10,269)	(12,791)	(7,262)
Loss from discontinued operations	-	(894)	(2,686)	(3,026)
Net loss	$ (3,257)	$ (11,163)	$ (15,477)	$ (10,288)
Change in fair value of commodity hedges	—	63	—	151
Cash settlement of commodity hedges	—	(1,722)	—	(4,367)
Other comprehensive loss	—	(1,659)	—	(4,216)
Comprehensive loss	$ (3,257)	$ (12,822)	$ (15,477)	$ (14,504)
Loss per unit (see Note 2)				
Loss from continuing operations per unit—Basic	$ (0.12)	$ (0.42)	$ (0.51)	$ (0.30)

Loss from discontinued operations per unit—Basic	—	(0.04)	(0.11)	(0.13)
Net loss per unit—Basic	$ (0.12)	$ (0.46)	$ (0.62)	$ (0.43)
Units outstanding—Basic	26,888,303	24,169,012	24,840,502	24,171,669
Loss from continuing operations per unit—Diluted	$ (0.12)	$ (0.42)	$ (0.51)	$ (0.30)
Loss from continuing operations per unit—Diluted	—	(0.04)	(0.11)	(0.13)
Net loss per unit—Diluted	$ (0.12)	$ (0.46)	$ (0.62)	$ (0.43)
Units outstanding—Diluted	26,888,303	24,169,012	24,840,502	24,171,669
Distributions declared and paid per unit	$ -	$ -	$ -	$ -

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(Unaudited)

	Nine months ended September 30, 2013	2012
Cash flows from operating activities:		
Net loss	$ (15,477)	$ (10,288)
Adjustments to reconcile net loss to cash provided by operating activities		
Depreciation, depletion and amortization	15,056	7,078
Asset impairments (see Note 6)	—	107
Amortization of debt issuance costs	1,228	974
Accretion expense	409	345
Equity earnings in affiliate	(224)	(129)
Gain from disposition of property and equipment	8	-
Bad debt expense	44	26
Loss from mark-to-market activities	7,635	7,756
Unit-based compensation programs	828	1,163
Discontinued operations	2,686	3,026
Changes in Assets and Liabilities:		
(Increase) decrease in accounts receivable	(1,212)	1,004
(Increase) decrease in prepaid expenses	(110)	278
Increase in other assets	(1,107)	(600)
Increase (decrease) in accounts payable	(434)	279
Decrease in accrued liabilities	(1,614)	(2,699)
Decrease in royalty payable	(54)	(47)
Increase in other liabilities	1,114	507
Net cash provided by continuing operations	8,776	8,780
Net cash provided by discontinued operations	1,062	2,655
Net cash provided by operating activities	9,838	11,435
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(20,221)	(75)
Development of oil and natural gas properties	(12,564)	(10,309)
Proceeds from sale of assets	58,987	1,505
Distributions from equity affiliate	135	150
Net cash provided by (used in) continuing operations	26,337	(8,729)

Net cash used in discontinued operations	—	(147)
Net cash provided by (used in) investing activities	26,337	(8,876)
Cash flows from financing activities:		
Proceeds from issuance of debt	16,894	—
Repayment of debt	(50,194)	(10,000)
Units tendered by employees for tax withholdings	(185)	(199)
Debt issue costs	(925)	(14)
Net cash used in continuing operations	(34,410)	(10,213)
Net cash used in discontinued operations	—	—
Net cash used in financing activities	(34,410)	(10,213)
Net (decrease) increase in cash and cash equivalents	1,765	(7,654)
Cash and cash equivalents, beginning of period	1,959	17,176
Cash and cash equivalents, end of period	$ 3,724	$ 9,522
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 333	$ 34
Cash received during the period for interest	$ —	$ 1
Cash paid during the period for interest	$ (1,405)	$ (2,812)

The accompanying notes are an integral part of these condensed consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Members' Equity

(In thousands, except unit data)

(Unaudited)

	Class A Units	Amount	Class B Units	Amount	Accumulated Other Comprehensive Income (Loss)	Total Members' Equity
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	3,940	17	191,642	811	—	828
Unit issuance cost	1,130,512	818	4,724,407	9,500	—	10,318
Net loss	—	(310)	—	(15,167)	—	(15,477)
Balance, September 30, 2013	1,615,017	$ 2,847	28,463,746	$ 108,903	$ —	$ 111,750

The accompanying notes are an integral part of these condensed consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Constellation Energy Partners LLC (CEP, we, us, our or the Company) was organized as a limited liability company on February 7, 2005, under 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, PostRock Energy Corporation (NASDAQ: PSTR) (PostRock), Exelon Corporation (NYSE: EXC) (Exelon) and Sanchez Oil & Gas Corporation (SOG) own a portion of our outstanding units. As of September 30, 2013, Constellation Energy Partners Management, LLC (CEPM), a subsidiary of PostRock, owned 484,505 of our Class A units and 5,918,894 of our Class B common units. 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. Sanchez Energy Partners I, LP (SEP I), a subsidiary of SOG, owned 1,130,512, or 70%, of our Class A units and 4,724,407 of our Class B common units.

We are currently focused on the acquisition, development and production of oil and natural gas properties, as well as midstream assets. Our proved reserves are located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas and in Texas and Louisiana.

Basis of Presentation

These unaudited condensed consolidated financial statements include the accounts of CEP 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.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules of the Securities and Exchange Commission (SEC). Certain information and footnote disclosures, normally included in annual financial statements prepared in accordance with accounting principles generally accepted in the United States (U.S. GAAP), have been condensed or omitted pursuant to those rules and regulations. We believe that the disclosures made are adequate to make the information presented not misleading. In the opinion of management, all adjustments, consisting only of normal recurring adjustments, necessary to fairly state the financial position, results of operations and cash flows with respect to the interim consolidated financial statements have been included. The results of operations for the interim periods are not necessarily indicative of the results for the entire year. The year-end balance sheet data was derived from audited financial statements, but does not include all disclosures required by U.S. GAAP.

These unaudited condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto of CEP and our subsidiaries included in our Annual Report on Form 10-K for the year ended December 31, 2012, which was filed with the SEC on March 11, 2013, and amended by Amendment No. 1 thereto filed with the SEC on April 18, 2013.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and accompanying footnotes. These estimates and the underlying assumptions affect the amounts of assets and liabilities reported disclosures about contingent assets and liabilities and reported amounts of revenues and expenses. The estimates that are particularly significant to our financial statements include estimates of our reserves of oil, natural gas and natural gas liquids (NGLs); future cash flows from oil and natural gas properties; depreciation, depletion and amortization; asset retirement obligations; certain revenues and operating expenses; fair values of commodity derivatives and fair values of assets and liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from the estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Reclassifications

Certain amounts in the prior period financial statements have been reclassified to conform to the current period presentation. These reclassifications had no impact on the previously reported net income (loss) for any periods.

New Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (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.

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 September 30, 2013, we had 1,615,017 Class A units and 28,463,746 Class B common units outstanding. Of the Class B common units, 386,579 units are restricted unvested common units granted and outstanding.

The following table presents earnings per common unit amounts (in thousands, except per unit data):

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Numerator:				
Loss from continuing operations allocable to unitholders	$ (3,257)	$ (10,269)	$ (12,791)	$ (7,262)
Loss from discontinued operations allocable to unitholders	—	(894)	(2,686)	(3,026)
Loss allocable to unitholders	$ (3,257)	$ (11,163)	$ (15,477)	$ (10,288)
Denominator:				
Weighted average units outstanding	26,888,303	24,169,012	24,840,502	24,171,669

Net earnings per unit:				
Basic:				
Loss from continuing operations allocable to unitholders	$ (0.12)	$ (0.42)	$ (0.51)	$ (0.30)
Loss from discontinued operations allocable to unitholders	—	(0.04)	(0.11)	(0.13)
Loss allocable to unitholders	$ (0.12)	$ (0.46)	$ (0.62)	$ (0.43)
Diluted:				
Loss from continuing operations allocable to unitholders	$ (0.12)	$ (0.42)	$ (0.51)	$ (0.30)
Loss from discontinued operations allocable to unitholders	—	(0.04)	(0.11)	(0.13)
Loss allocable to unitholders	$ (0.12)	$ (0.46)	$ (0.62)	$ (0.43)

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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. There were no checks-in-transit reported in accounts payable at September 30, 2013, and our checks-in-transit reported in accounts payable were $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 September 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 September 30, 2013. These funds will be held in escrow for a period up to twenty-four months, ending February 28, 2015, pending certain closing conditions.

3. ACQUISITION AND DIVESTITURE

Sale of Robinson's Bend Field Assets

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. We recorded a loss on the sale of approximately $3.1 million in the three months ended March 31, 2013.

Acquisition of Oil, Natural Gas and Natural Gas Liquids Properties From SEP I

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. 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 and 4,724,407 Class B units, which represents 16.6% of the total Class B. The cash portion of the transaction was financed with cash on hand and a borrowing of $16.7 million under our reserve-based credit facility.

The acquired assets include 67 producing wells in Texas and Louisiana. The primary factors considered by management in acquiring the Sep I properties include the belief that these wells provide an opportunity to significantly increase our reserves, production volumes and drilling portfolio, while maintaining our focus of increasing our oil-weighted assets. The SEP I properties also provide us with access to exploitation and development potential.

The following allocation of the purchase price is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these condensed consolidated financial statements were prepared and takes into account current market conditions and estimated market prices for oil and natural gas. Management has not yet had the opportunity to complete its assessment of fair values of the assets acquired. In addition, the purchase price could change materially as management finalizes adjustments to the purchase price provided for by the purchase and sale agreement. Accordingly, the allocation may change materially as additional information becomes available and is assessed by management.

The following table summarizes the estimated values of assets acquired and liabilities assumed effective August 1, 2013 (in thousands):

	August 1, 2013
Oil and natural gas properties, equipment and facilities	$ 30,409
Asset retirement obligation	(1,088)
Net assets acquired	$ 29,321

We will finalize the purchase price allocation within one year of the acquisition date.

We have accounted for our acquisition of oil and natural gas properties using the purchase method of accounting for business combinations, and therefore we have estimated the fair value of the assets acquired and the liabilities assumed as of the acquisition date. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) estimated future cash flows and (v) a market-based weighted cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

Results of Operations and Pro Forma Information

The following table sets forth revenues and lease operating expenses attributable to the SEP I properties acquired (in thousands):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
Revenue	$ 3,936	$ 4,516	$ 12,764	$ 15,904
Lease Operating Expenses	$ 797	$ 1,184	$ 3,018	$ 3,795

We have determined that the presentation of net income attributable to the SEP I properties is impracticable due to the integration of the related operations upon acquisition.

The following supplemental pro forma information presents consolidated results of operations as if the acquisition of the SEP I properties had occurred on January 1, 2012. The supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations and b) the statements of operations of SEP I. This information does not purport to be indicative of results of operations that would have occurred had the acquisition occurred on January 1, 2012, nor is such information indicative of any expected future results of operations.

	Pro Forma		Pro Forma	
	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
(In thousands)	2013	2012	2013	2012
Revenue	$ 16,067	$ 7,793	$ 45,383	$ 48,994
Net Loss	$ (1,433)	$ (8,370)	$ (8,569)	$ (186)
Basic loss per unit	$ (0.05)	$ (0.28)	$ (0.29)	$ (0.01)
Diluted loss per unit	$ (0.05)	$ (0.28)	$ (0.29)	$ (0.01)

4. FAIR VALUE MEASUREMENTS

We measure certain financial assets and liabilities at fair value. Fair value is defined as an “exit price” which represents the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in valuing an asset or liability. The accounting guidance also requires the use of valuation techniques to measure fair value that maximize the use of observable inputs and minimize the use of unobservable inputs. As a basis for considering such assumptions and inputs, a fair value hierarchy has been established which identifies and prioritizes three levels of inputs to be used in measuring fair value.

The three levels of the fair value hierarchy are as follows:

Level 1 – Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 – Inputs other than the quoted prices in active markets that are observable either directly or indirectly, including: quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active or other inputs that are observable or can be corroborated by observable market data.

Level 3 – Unobservable inputs that are supported by little or no market data and require the reporting entity to develop its own assumptions.

As required by accounting guidance for fair value measurements, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 (in thousands):

	Fair Value Measurements at September 30, 2013				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at September 30, 2013
Risk Mgmt Assets	$ —	$ 18,225	$ —	$ (1,625)	$ 16,600
Risk Mgmt Liabilities	—	(1,625)	—	1,625	—
Total Net Assets and Liabilities	$ —	$ 16,600	$ —	$ —	$ 16,600

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 (in thousands):

	Fair Value Measurements at December 31, 2012				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2012
Risk Mgmt Assets	$ —	$ 31,030	$ —	$ (5,634)	$ 25,396
Risk Mgmt Liabilities	—	(6,794)	—	5,634	(1,160)
Total Net Assets and Liabilities	$ —	$ 24,236	$ —	$ —	$ 24,236

As of September 30, 2013, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value of Financial Instruments

Fair value guidance requires certain fair value disclosures, such as those on our debt and derivatives, to be presented in both interim and annual reports. The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

Reserve-Based Credit Facility – We believe that 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. The debt is classified as a Level 2 input 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 further in Note 7.

Derivative Instruments – 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 inputs. 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.

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These transactions are normally price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under ASC Topic 815, “Derivatives and Hedging,” all derivative instruments are recorded on the condensed consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives’ fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have elected to designate only a portion of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included as realized and unrealized gains (losses) on derivative instruments in the condensed consolidated statements of operations.

As of September 30, 2013, we had the following derivative contracts in place for the periods indicated, all of which 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,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2013							1,691,540	$ 6.18	1,691,540	$ 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
									13,595,489	

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,		September 30,		December 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2013							1,223,985	$ 0.39	1,223,985	$ 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
									5,667,662	

MTM Fixed Price Basis Swaps–West Texas Intermediate (WTI)

	For the quarter ended (in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2013							65,256	$ 99.93	65,256	$ 99.93
2014	60,928	$ 94.64	57,154	$ 94.67	53,797	$ 94.72	50,597	$ 94.80	222,476	$ 94.70
2015	47,747	$ 90.95	45,065	$ 91.00	42,672	$ 91.04	40,329	$ 91.10	175,813	$ 91.02
2016	17,957	$ 85.50	16,985	$ 85.50	16,048	$ 85.50	15,127	$ 85.50	66,117	$ 85.50
									529,662	

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The table below outlines the classification of our derivative financial instruments on the condensed consolidated balance sheet (in thousands):

Derivative Type	Location of Asset/(Liability) On Balance Sheet	Fair Value of Asset/(Liability) On Balance Sheet September 30, 2013	December 31, 2012
Commodity – MTM	Risk management assets - current	$ 13,581	$ 19,005
Commodity – MTM	Risk management assets - non-current	4,644	12,025
	Total gross assets	18,225	31,030
Commodity – MTM	Risk management assets – current	(1,385)	(1,040)
Commodity – MTM	Risk management assets – non-current	(240)	(946)
Commodity – MTM	Rick management liabilities – current	—	(523)
Commodity – MTM	Risk management liabilities – non-current	—	(637)
Interest Rate - MTM	Risk management assets – non-current	—	(3,648)
	Total gross liabilities	(1,625)	(6,794)
	Total net assets and liabilities	$ 16,600	$ 24,236

The effect of derivative instruments on our condensed consolidated statements of operations was as follows (in thousands):

Derivative Type	Location of Gain/(Loss) in Income	Amount of Gain/(Loss) in Income For the Three Months Ended September 30, 2013	2012
Commodity – MTM – Unrealized	Natural gas sales	$ (2,995)	$ (8,746)
Commodity – MTM – Unrealized	Oil and liquids sales	(1,350)	(1,412)
Commodity – MTM – Realized	Natural gas sales	4,174	5,934
Commodity – MTM – Realized	Oil and liquids sales	(235)	302
Interest Rate – MTM – Unrealized	Interest expense	—	92
Interest Rate – MTM - Realized	Interest expense	—	(460)
	Total	$ (406)	$ (4,290)

Derivative Type	Location of Gain/(Loss) in Income	Amount of Gain/(Loss) in Income For the Nine Months Ended September 30, 2013	2012
Commodity – MTM – Unrealized	Natural gas sales	$ (10,124)	$ (9,329)
Commodity – MTM – Unrealized	Oil and liquids sales	(1,160)	876
Commodity – MTM – Realized	Natural gas sales	11,448	19,200
Commodity – MTM – Realized	Oil and liquids sales	272	426
Interest Rate – MTM – Unrealized	Interest expense	3,648	697
Interest Rate – MTM - Realized	Interest expense	(3,713)	(1,746)
	Total	$ 371	$ 10,124

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 For the Three Months Ended September 30, 2013	2012
Commodity – Cash Flow	Natural gas sales	$ —	$ 1,722
	Total	$ —	$ 1,722

	Location of Gain/(Loss) for	Amount of Gain/(Loss) Reclassified from AOCI into Income – Effective

Derivative Type	Effective and Ineffective Portion of Derivative in Income	For the Nine Months Ended September 30, 2013	2012
Commodity – Cash Flow	Natural gas sales	$ —	$ 4,367
	Total	$ —	$ 4,367

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Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with two counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

We monitor the creditworthiness of our counterparties; however, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, if such changes are sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of our counterparties not perform, we may not realize the benefit of some of our derivative instruments with lower commodity prices and may incur losses. We include a measure of counterparty credit risk in our estimates of the fair values of the derivative instruments in an asset position.

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 our 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 September 30, 2013, the impact of non-performance credit risk on the valuation of our net assets from counterparties was not significant. At September 30, 2012, the impact of non-performance credit risk on the valuation of our net assets from counterparties was \$0.2 million, of which \$0.1 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.

Under the terms of our reserve-based credit facility, we have agreed to hedge 100% of our reasonably estimated projected natural gas production for 2015 and 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.

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 one of our counterparties at a fixed price of \$3.66. These transactions ensure that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods. 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.

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 terminated in May 2013 resulting in an offsetting non-cash gain in our mark-to-market interest swap activities.

6. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consisted of the following (in thousands):

	September 30, 2013	December 31, 2012
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 635,993	$ 591,889
Unproved property	1,487	1,380
Total property costs	637,480	593,269
Materials and supplies	846	771
Land	751	751
Total	639,077	594,791
Less: Accumulated depreciation, depletion, amortization and impairments	(489,083)	(474,669)
Oil and natural gas properties and equipment, net	$ 149,994	$ 120,122

Depletion, depreciation, amortization and impairments consisted of the following (in thousands):

	Nine Months Ended September 30, 2013	2012
DD&A of oil and natural gas-related assets	$ 15,056	$ 7,078
Asset Impairments	—	107
Total	$ 15,056	$ 7,185

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

For the three months ended September 30, 2013, we did not have an impairment to record. 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 excluded 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 based on the final settlement statement. See Note 13 for additional information.

In the nine months ended September 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 nine months ended September 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.

7. 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 September 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. This reserve-based credit facility had a borrowing base of $55.0 million and matures on May 30, 2017. At September 30, 2013, we had $50.7 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%).

At our election, interest for borrowings is 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 and make certain loans, acquisitions, capital expenditures and investments. 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 nine months ended September 30, 2013, we accelerated the amortization of approximately $0.7 million of debt issue costs as a result of amendments to 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 September 30, 2013, our unamortized debt issue costs were approximately $0.9 million. These costs are being amortized over the life of our reserve-based credit facility.

Funds Available for Borrowing

As of September 30, 2013 and 2012, we had $50.7 million and $88.4 million, respectively, in outstanding debt under our reserve-based credit facility. As of September 30, 2013, we had $4.3 million borrowing capacity available under our reserve-based credit facility.

Compliance with Debt Covenants

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

8. 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 (in thousands):

	September 30, 2013	December 31, 2012
Asset retirement obligation, beginning balance	$ 7,665	$ 7,052
Liabilities incurred	1,254	162
Liabilities settled	(3)	(8)
Accretion expense	409	459
Asset retirement obligation, ending balance	$ 9,325	$ 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 September 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.

9. COMMITMENTS AND CONTINGENCIES

On August 30, 2013, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPM, Gary M. Pittman and John R. Collins against the Company, certain of its officers and managers, SOG and SEP I in connection with the Company's closing on August 9, 2013 of the purchase of oil and gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contend, among other things, that the issuance of the units to SEP I in connection with the acquisition was not permitted under the Company's operating agreement, that Messrs. Pittman and Collins should not have been removed as the Class A managers of the Company's board of managers, and that SEP I, SOG and our current Class A managers participated in the bad faith conduct of the other defendants and interfered with CEPM's contractual rights under the Company's operating agreement. The plaintiffs allege claims against the Company and certain of its managers and officers relating to breach of contract, breach of the duty of good faith, and breach of the implied covenant of good faith and fair dealing; the plaintiffs also allege aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs seek, among other things, declaratory relief reappointing Messrs. Pittman and Collins to the Company's board of managers and removing our current Class A managers therefrom, and an injunction against the Company taking any further action outside the ordinary course of business during the pendency of the litigation, declaratory relief rescinding the units issued by the Company to SEP I, declaratory relief that CEPM has sole voting power with respect to the outstanding Class A units, declaratory relief that the Company's officers and managers have breached fiduciary and contractual duties and are not entitled to indemnification from the Company as a result thereof, and monetary damages. The lawsuit is currently in the discovery phase with a hearing on the plaintiff's application for an injunction seeking to enjoin the Company's December 5, 2013 annual meeting of unitholders scheduled for December 2, 2013, and the trial scheduled for December 16, 17 and18 in Wilmington, Delaware. The Company believes that the allegations contained in the lawsuit are without merit and intends to vigorously defend itself and its officers and managers against the claims raised in the complaint.

10. RELATED PARTY TRANSACTIONS

Unit Ownership

PostRock, Exelon and SOG, through subsidiaries, own a portion of our outstanding units. As of September 30, 2013, CEPM, a subsidiary of PostRock, owned 484,505 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 September 30, 2013. SEP I, a subsidiary of SOG, owned 1,130,512, or 70%, of our Class A units and 4,724,407 of our Class B common units.

Class C Management Incentive Interests

CEPH, a subsidiary of Exelon, held all of the Class C management incentive interests in CEP as of September 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.

11. COMPENSATION

We recognized approximately $0.8 million and $1.2 million of non-cash compensation expense related to our unit-based compensation plans in the nine months ended September 30, 2013, and September 30, 2012, respectively. As of September 30, 2013, we had approximately $0.6 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 nine months ended September 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.

12. 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.

13. MEMBERS' EQUITY

2013 Equity

At September 30, 2013, we had 1,615,017 Class A units and 28,463,746 Class B common units outstanding, which included 43,776 unvested restricted common units issued under our Long-Term Incentive Plan and 342,803 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At September 30, 2013, we had granted 346,734 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 302,958 have vested.

At September 30, 2013, we had granted 1,368,227 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 1,025,424 have vested.

For the nine months ended September 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 September 30, 2012, we had 483,304 Class A units and 23,681,878 Class B common units outstanding, which included 94,914 unvested restricted common units issued under our Long-Term Incentive Plan and 665,840 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At September 30, 2012, we had granted 336,599 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 241,685 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 September 30, 2012, we had granted 1,320,901 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 655,061 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 nine months ended September 30, 2012, 89,271 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.

14. DISCONTINUED OPERATIONS

On January 31, 2013, our Board of Managers authorized the sale of the two entities that owned all of 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. We 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 24 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, based on post-closing adjustments.

During the nine months ended September 30, 2013, our discontinued operations had a net loss of $2.7 million consisting of revenues of $2.3 million, offset by expenses of $1.9 million and a loss on sale of $3.1 million. During the nine months ended September 30, 2012, our discontinued operations had a net loss of $3.0 million consisting of revenues of $9.0 million offset by expenses of $12.0 million. During the three months ended September 30, 2012, our discontinued operations had a net loss of $0.9 million consisting of revenues of $3.2 million offset by expenses of $4.1 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.

15. SUBSEQUENT EVENTS

We evaluated subsequent events through the time of filing this Quarterly Report on Form 10-Q. No subsequent events occurred subsequent to the balance sheet or prior to the filing of this report that would have a material impact on our consolidated financial statements or results of operations.

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. We are focused on the acquisition, development and production of oil and natural gas properties, as well as midstream assets. Our proved reserves are located in the Cherokee Basin in Oklahoma, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas and 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 and in Texas and Louisiana;

•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. Referer 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 “SOG” and “SEP I” are to Sanchez Oil & Gas Corporation and its subsidiary, Sanchez Energy Partners I, LP, respectively.

How We Evaluate our Operations

Non-GAAP Financial Measure—Adjusted EBITDA

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

•interest (income) expense, net which includes:

• interest expense

•interest expense gain/(loss) mark-to-market activities

• interest (income)

•depreciation, depletion and amortization;

•write-off of deferred financing fees;

•asset impairments;

•accretion expense;

•(gain) loss on sale of assets;

•(gain) loss from equity investment;

•unit-based compensation programs;

•(gain) loss from mark-to-market activities; and

•gain (loss) on discontinued operations;

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 U.S. 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 U.S. 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 U.S. GAAP performance measure, for each of the periods presented (in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Net loss	$ (3,257)	$ (11,163)	$ (15,477)	$ (10,288)
Adjusted by:				
Interest expense, net	420	1,534	2,636	4,590
Depreciation, depletion and amortization	5,491	2,373	15,056	7,078
Asset impairments	—	—	—	107
Accretion expense	163	116	409	345
Loss on sale of assets	31	—	8	—
Unit-based compensation programs	219	498	828	1,163
Loss on mark-to-market activities	4,345	10,158	11,284	8,453
Loss on discontinued operations	—	894	2,686	3,026
Adjusted EBITDA	$ 7,412	$ 4,410	$ 17,430	$ 14,474

Our Adjusted EBITDA from our continuing operations was $7.4 million for the three months ended September 30, 2013, which is higher than our Adjusted EBITDA of $4.4 million in the same period in 2012. The increase is the result of increased oil production, higher gas prices and reductions in general and administrative expenses.

Our Adjusted EBITDA was $17.4 million for the nine months ended September 30, 2013, higher than our Adjusted EBITDA of $14.5 million in the same period in 2012 resulting from increased oil production, higher gas prices and reductions in lease operating and general and administrative expenses.

Some key highlights of our business activities through September 30, 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.

- We have implemented strategies to reduce our general and administrative expenses and our lease operating expenses going forward. During the first nine months of 2013, we incurred a general and administrative charge of approximately $1.0 million associated with severance costs. Excluding this charge and non-cash unit-based compensation costs, our nine months ended September 30, 2013 cash general and administrative expenses and lease operating expenses decreased by 10.6% 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. Oil production for the nine months ended September 30, 2013 increased by 84% over our oil production for the same period in 2012. Oil revenues accounted for 50% of our total unhedged revenue for the nine months ended September 30, 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.

During the fourth quarter of 2013, we intend to continue focusing our efforts on developing oil opportunities on our existing properties in the Mid-Continent region, Texas and Louisiana 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. We anticipate managing 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 nine months ended September 30, 2013, was $7.48 per Mcfe including hedge settlements and $5.48 per Mcfe excluding hedge settlements. After deducting the cost of sales associated with our third party gathering, our average realized prices were $7.29 per Mcfe including hedge settlements and $5.29 per Mcfe excluding hedge settlements.

- Production. Our production for the nine months ended September 30, 2013, was 5.9 Bcfe, or an average of 21,502 Mcfe per day, compared with approximately 6.2 Bcfe, or an average of 22,544 Mcfe per day, for the nine months ended September 30, 2012. Our oil production increased 85.4% for the nine months ended September 30, 2013 when compared to the same period in 2012. Our 2013 production was 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 nine months of 2013, we spent approximately $32.8 million in cash capital expenditures, consisting of $12.1 million in development expenditures focused on oil completions in the Cherokee Basin, $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin, $20.1 million to acquire SEP I properties, and $0.5 million in development expenditures focused on SEP I acquired properties. We completed 46 net wells and 13 net recompletions during the nine months ended September 30, 2013 and had 20 net wells and net recompletions in progress at September 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. During the first nine months of 2013, our daily average net oil production increased to 564 barrels from our average daily net production of 307 barrels for the same time period of 2012.

• Hedging Activities. All of our commodity and interest rate derivatives are accounted for as mark-to-market activities. For the nine months ended September 30, 2013, the unrealized non-cash mark-to-market loss for our commodity derivatives was approximately $11.3 million as compared to an unrealized non-cash mark-to-market loss of $8.5 million for the same period in 2012.

• Debt Reduction. We reduced our outstanding debt from a high of $220.0 million in 2009 to $50.7 million as of September 30, 2013. At September 30, 2013, we had $50.7 million in outstanding debt and $4.3 million in unused borrowing capacity under our reserve-based credit facility.

• Operating Expense Reductions. We have implemented strategies to reduce our structural general and administrative expenses and to further reduce our lease operating expenses. These strategies included: 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.

Results of Operations

The following table sets forth the selected financial and operating data for the periods indicated (dollars in thousands):

	For the Three Months Ended				For the Nine Months Ended			
	September 30,		Variance		September 30,		Variance	
	2013	2012	$	%	2013	2012	$	%
Revenues:								
Natural gas sales at market price	$ 5,384	$ 3,987	$ 1,397	35.0%	$ 15,003	$ 11,034	$ 3,969	36.0%
Natural gas hedge settlements	4,174	5,935	(1,761)	(29.7%)	11,448	19,200	(7,752)	(40.4%)
Natural gas mark-to-market activities	(2,995)	(8,746)	5,751	65.8%	(10,124)	(9,329)	(795)	(8.5%)
Natural gas total	6,563	1,176	5,387	458.1%	16,327	20,905	(4,578)	(21.9%)
Oil and liquids sales	6,388	2,488	3,900	156.8%	14,762	8,545	6,217	72.8%
Oil hedge settlements	(235)	303	(538)	(177.6%)	272	426	(154)	(36.2%)
Oil mark-to-market activities	(1,350)	(1,412)	62	4.4%	(1,160)	876	(2,036)	(232.4%)
Oil and liquids total	4,803	1,379	3,424	248.3%	13,874	9,847	4,027	40.9%
Other natural gas sales at market price	765	722	43	6.0%	2,418	2,338	80	3.42%
Total revenues	12,131	3,277	8,854	270.2%	32,619	33,090	(471)	(1.4%)
Operating expenses:								
Lease operating expenses	5,191	4,869	322	6.6%	13,332	14,727	(1,395)	(9.5%)
Cost of sales	323	287	36	12.5%	1,122	923	199	21.6%
Production taxes	731	374	357	95.5%	1,840	1,141	699	61.3%
General and administrative	3,015	4,014	(999)	(24.9%)	11,156	11,555	(399)	(3.5%)
Gain on sale of assets	31	—	31	100.0%	8	—	8	100.0%
Depreciation, depletion and amortization	5,491	2,373	3,118	131.4%	15,056	7,078	7,978	112.7%
Asset impairments	—	—	—	—	—	107	(107)	(100.0%)
Accretion expenses	163	116	47	40.5%	409	345	64	18.6%
Total operating expenses	14,945	12,033	2,912	24.20%	42,923	35,876	7,047	19.6%
Other expenses (income):								
Interest expense	420	1,626	(1,206)	(74.2%)	6,284	5,288	996	18.8%
Interest expense-Gain from mark-to-market activities	—	(92)	92	100.0%	(3,648)	(697)	(2,951)	(423.4%)
Interest income	—	—	—	—	—	(1)	1	100.0%

Other (income) expense	23	(21)	44	209.5%	(149)	(114)	(35)	(30.7%)
Total other expenses	443	1,513	(1,070)	(70.7%)	2,487	4,476	(1,989)	(44.4%)
Total expenses	15,388	13,546	1,842	13.6%	45,410	40,352	5,058	12.5%
Loss on discontinued operations	—	(894)	894	100.0%	(2,686)	(3,026)	340	11.2%
Net income (loss)	$ (3,257)	$ (11,163)	$ 7,906	70.8%	$ (15,477)	$ (10,288)	$ (5,189)	(50.4%)

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	For the Three Months Ended September 30, 2013	2012	Variance $	%	For the Nine Months Ended September 30, 2013	2012	Variance $	%
Net production:								
Natural gas production (MMcf)	1,630	1,872	(242)	(12.9%)	4,946	5,674	(728)	(12.8%)
Oil and liquids production (MBbl)	63	25	38	153.6%	154	83	71	85.4%
Total production (MMcfe)	2,011	2,022	(12)	(0.6%)	5,870	6,177	(307)	(5.0%)
Average daily production (Mcfe/d)	21,853	21,978	(125)	(0.6%)	21,502	22,544	(1,042)	(4.6%)
Total production (MBOE)	335	337	(2)	(0.6%)	978	1,029	(51)	(5.0%)
Average daily production (BOE/d)	3,642	3,662	(20)	(0.6%)	3,583	3,757	(174)	(4.6%)
Average sales prices:								
Natural gas price per Mcf with hedge settlements	$ 6.33	$ 5.69	$ 0.65	11.4%	$ 5.84	$ 5.74	$ 0.10	1.7%
Natural gas price per Mcf without hedge settlements	$ 3.77	$ 2.52	$ 1.26	50.0%	$ 3.52	$ 2.36	$ 1.17	49.5%
Oil and liquids price per Bbl with hedge settlements	$ 97.05	$ 111.64	$ (14.59)	(13.1%)	$ 97.69	$ 108.08	$ (10.40)	(9.6%)
Oil and liquids price per Bbl without hedge settlements	$ 100.76	$ 99.52	$ 1.24	1.2%	$ 95.92	$ 102.95	$ (7.03)	(6.8%)
Total price per Mcfe with hedge settlements	$ 8.19	$ 6.64	$ 1.55	23.3%	$ 7.48	$ 6.73	$ 0.75	11.2%
Total price per Mcfe without hedge settlements	$ 6.24	$ 3.56	$ 2.68	75.2%	$ 5.48	$ 3.55	$ 1.93	54.5%
Total price per BOE with hedge settlements	$ 49.18	$ 39.87	$ 9.31	23.4%	$ 44.88	$ 40.35	$ 4.53	11.2%
Total price per BOE without hedge settlements	$ 37.42	$ 21.36	$ 16.06	75.2%	$ 32.90	$ 21.29	$ 11.61	54.5%
Average unit costs per Mcfe:								
Field operating expenses[(a)]	$ 2.95	$ 2.59	$ 0.35	13.6%	$ 2.58	$ 2.57	$ 0.02	0.6%
Lease operating expenses	$ 2.58	$ 2.41	$ 0.17	7.2%	$ 2.27	$ 2.38	$ (0.11)	(4.7%)
Production taxes	$ 0.36	$ 0.18	$ 0.18	96.6%	$ 0.31	$ 0.18	$ 0.13	69.7%
General and administrative	$ 1.50	$ 1.99	$ (0.49)	(11.0%)	$ 1.90	$ 1.87	$ 0.03	1.6%
General and administrative w/o unit-based compensation	$ 1.39	$ 1.74	$ (0.35)	(16.5%)	$ 1.76	$ 1.69	$ 0.07	4.4%
Depreciation, depletion and amortization	$ 2.73	$ 1.17	$ 1.56	132.7%	$ 2.56	$ 1.15	$ 1.42	123.8%
Average unit costs per BOE:								
Field operating expenses[(a)]	$ 17.68	$ 15.56	$ 2.12	13.6%	$ 15.51	$ 15.41	$ 0.10	0.6%

Lease operating expenses	$ 15.49	$ 14.45	$ 1.05	7.2%	$ 13.63	$ 14.31	$ (0.68)	(4.7%)
Production taxes	$ 2.18	$ 1.11	$ 1.07	96.6%	$ 1.88	$ 1.11	$ 0.77	69.7%
General and administrative	$ 9.00	$ 11.91	$ (2.91)	(24.4%)	$ 11.41	$ 11.22	$ 0.18	1.6%
General and administrative w/o unit-based compensation	$ 8.35	$ 10.45	$ (2.11)	(20.2%)	$ 10.56	$ 10.11	$ 0.45	4.4%
Depreciation, depletion and amortization	$ 16.39	$ 7.04	$ 9.35	132.8%	$ 15.39	$ 6.88	$ 8.52	123.9%

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

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

Oil and natural gas sales. Unhedged oil and liquid sales increased $3.9 million, or 156.8%, to $6.4 million for the three months ended September 30, 2013 as compared to $2.5 million for the same period in 2012. Unhedged natural gas sales increased $1.4 million, or 35.0%, to $5.4 million for the three months ended September 30, 2013 as compared to $3.9 million for the same period in 2012. With hedges and mark-to-market activities, our total revenue increased $8.9 million when compared to the same period in 2012. Of this increase, $5.4 million was attributable to higher market prices for our natural gas production and higher market prices for our oil production and $5.8 million in higher mark-to-market activities, partially offset by $2.3 million attributable to lower cash hedge settlements from our hedge program. Production for the three months ended September 30, 2013 was 2.0 Bcfe, which was comparable to the same period in 2012. We hedged all of our actual consolidated production volumes sold through September 30, 2013, and approximately 94% of our actual production through September 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 $3.9 million for the three months ended September 30, 2013. Cash hedge settlements received for our commodity derivatives were approximately $6.2 million for the three months ended September 30, 2012. This difference is due to changes in hedge prices, hedged volumes, and market prices for natural gas and oil during 2012 and 2013.

As discussed below, our unrealized non-cash mark-to-market activities increased by $5.9 million for the three months ended September 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 September 30, 2013, the unrealized non-cash mark-to-market loss was approximately $4.3 million as compared to an unrealized non-cash mark-to-market loss of $10.2 million for the same period in 2012. The 2013 non-cash loss represents approximately $4.3 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 while non-performance risk was not a factor. The 2012 non-cash loss represented approximately $10.5 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 $0.3 million related to non-performance risk associated with our counterparties.

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

For the three months ended September 30, 2013, lease operating expenses increased $0.3 million, or 6.5%, to $5.2 million, compared to expenses of $4.9 million for the same period in 2012. This increase in lease operating expenses is primarily related to $0.3 million in higher expenses due to the SEP I acquisition. By category, our lease operating expenses were higher in 2013 as compared to 2012 by $0.3 million because of an increase of $0.2 million in labor costs and $0.1 million in higher insurance costs.

For the three months ended September 30, 2013, per unit lease operating expenses were $2.58 per Mcfe compared to $2.41 per Mcfe for the same period in 2012.

For the three months ended September 30, 2013, production taxes increased $0.3 million, or 95.5%, to $0.7 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.

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 decreased $1.0 million, or 24.9%, to $3.0 million for the three months ended September 30, 2013, compared to $4.0 million for the same period in 2012. Our general and administrative expenses were lower in 2013 due to $0.6 million in decreased labor and incentive compensation costs, $0.3 million in decreased professional services and consulting costs and $0.3 million in lower unit compensation costs partially offset by $0.2 million in higher board of director’s compensation.

Our per unit costs were $1.50 per Mcfe for the three months ended September 30, 2013, as compared to $1.99 per Mcfe for the same period in 2012.

Depreciation, depletion and amortization expense. 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 September 30, 2013 was $5.5 million, or $2.73 per Mcfe, compared to $2.4 million, or $1.17 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 in 2013 as compared to 2012. Our other assets are depreciated using the straight-line basis. Consistent with our prior practice, we used 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.

Interest expense. Interest expense for the three months ended September 30, 2013 decreased $1.1 million, or 72.6%, to $0.4 million as compared to $1.5 million for the same period in 2012. This decrease was primarily due to lower market interest expense on our outstanding debt of $0.7 million, lower interest rate swap settlements of $0.5 million and $0.1 million in higher non-cash mark-to-market gains on our interest rate swaps that were accounted for as mark-to-market activities. At September 30, 2013, we had an outstanding balance under our reserve-based credit facility of $50.7 million compared to $88.4 million at September 30, 2012. The average interest rate on our outstanding debt was approximately 3.68% at September 30, 2013 compared to 6.0% during the same period in 2012.

Nine months ended September 30, 2013 compared to nine months ended September 30, 2012

Oil and natural gas sales. Unhedged oil and liquid sales increased $6.2 million, or 72.8%, to $14.8 million for the nine months ended September 30, 2013 compared to $8.5 million for the same period in 2012. Unhedged natural gas sales increased $4.0 million, or 36.0%, to $15.0 million for the nine months ended September 30, 2013, compared to $11.0 million for the same period in 2012. With hedges and mark-to-market activities, our total revenue decreased $0.5 million when compared to the same period in 2012. Of this decrease, $7.9 million was attributable to lower cash hedge settlements from our hedge program, $2.8 million in lower mark-to-market activities and $1.1 million was attributable to decreased natural gas production volumes, partially offset by $11.3 million 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 nine months ended September 30, 2013 was 5.9 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 September 30, 2013. We hedged all of our actual consolidated production volumes sold through September 30, 2013, and approximately 83% of our actual production through September 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 $11.7 million for the nine months ended September 30, 2013. Cash hedge settlements received for our commodity derivatives were approximately $19.6 million for the nine months ended September 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 $2.8 million for the nine months ended September 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 nine months ended September 30, 2013, the unrealized non-cash mark-to-market loss was approximately $11.3 million as compared to an unrealized non-cash mark-to-market loss of $8.5 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 $11.3 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 while non-performance risk associated with our counterparties was not a factor. The 2012 non-cash loss represented approximately $8.6 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 $0.2 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 nine months ended September 30, 2013, lease operating expenses decreased $1.4 million, or 9.5%, to $13.3 million, compared to expenses of $14.7 million for the same period in 2012. This decrease in lease operating expenses is primarily related to lower expenses in the Cherokee Basin. Our lease operating expenses were lower in 2013 compared to 2012 because of decreases of $1.2 million in elective costs such as well servicing and repairs and maintenance, $0.4 million in lower insurance and $0.1 million in lower ad valorem taxes, partially offset by $0.3 million in higher labor costs.

For the nine months ended September 30, 2013, per unit lease operating expenses were $2.27 per Mcfe compared to $2.38 per Mcfe for the same period in 2012.

For the nine months ended September 30, 2013, production taxes increased $0.7 million, or 61.3%, to $1.8 million, compared to expenses of $1.1 million for the same period in 2012. This increase is primarily the result of higher market prices for natural gas and oil in 2013 partially offset by the impact of lower production of 0.3 Bcfe in 2013.

Cost of sales. For the nine months ended September 30, 2013, cost of sales increased by $0.2 million, or 21.6%, to $1.1 million, compared to $0.9 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 decreased $0.4 million, or 3.5%, to $11.2 million for the nine months ended September 30, 2013, as compared to $11.6 million for the same period in 2012. Our general and administrative expenses were lower in 2013 compared to 2012 because of $1.1 million in lower professional services and consulting costs, including the costs associated with the termination of our support services agreement for revenue accounting services, and $0.3 million in lower unit based compensation, partially offset by $1.0 million in severance costs. Without the severance costs, our total reported general and administrative expenses for the nine months ended September 30, 2013, would have been lower by approximately $1.2 million as compared to the same period in 2012.

Our per unit costs were $1.90 per Mcfe for the nine months ended September 30, 2013, compared to $1.87 per Mcfe for the same period in 2012. This increase is attributable to the impact of 0.3 Bcfe in lower production and by a decrease in total spending of approximately $0.4 million. Excluding the impact of the severance costs, our total per unit costs excluding non-cash unit-based compensation expenses would have been $1.73 per Mcfe in 2013.

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 nine months ended September 30, 2013 was $15.1 million, or $2.56 per Mcfe, compared to $7.1 million, or $1.15 per Mcfe, for the same period in 2012. This increase 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 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 nine months ended September 30, 2012, we recorded an asset impairment of $0.1 million. Our non-cash impairment charge in 2012 was recorded 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 nine months ended September 30, 2013 decreased $2.0 million, or 42.6%, to $2.6 million, compared to $4.6 million for the same period in 2012. This decrease was primarily due to $3.0 million in lower non-cash mark-to-market losses on our interest rate swaps that are accounted for as mark-to-market activities, lower market interest expense of $1.0 million and higher interest rate swap settlements of $2.0 million, while capitalized interest remained flat in 2013 compared to the same period in 2012. At September 30, 2013, we had an outstanding balance under our reserve-based credit facility of $50.7 million compared to $88.4 million at September 30, 2012. The average interest rate on our outstanding debt was approximately 3.68% as of September 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.

Discontinued Operations. Loss from discontinued operations for the nine months ended September 30, 2013 decreased $0.3 million, or 11.2%, to a loss of $2.7 million, compared to a loss of $3.0 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 November 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, primarily 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 our 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 third quarter of 2013. At September 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 through the fourth quarter of 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 November 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 nine months ended September 30, 2013 was $9.8 million, compared to $11.4 million for the same period in 2012. This $1.6 million decrease in operating cash flow is attributable to the impact of $1.6 million in lower cash flow from discontinued operations and changes in working capital.

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, we have hedged approximately 1.7 Bcfe of its natural gas production at an effective NYMEX fixed price of $6.18 per Mcfe with Mid-Continent basis hedges on 1.2 Bcfe of this amount at an average differential of $0.39 per Mcfe. We also have hedges in place on approximately 65 MBbl of its oil production at a fixed price of $99.93 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.

Investing Activities—Acquisitions and Capital Expenditures

Cash provided by investing activities was $26.3 million for the nine months ended September 30, 2013, compared to cash used in investing activities of $8.9 million for the same period in 2012. Our cash capital expenditures were $32.8, consisting of $12.1 million in development expenditures focused on oil completions in the Cherokee Basin, $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin, $20.1 million to acquire SEP I wells and $0.5 million in development expenditures focused on SEP I properties. We have completed 46 net wells and 13 net recompletions during the nine months ended September 30, 2013 and have 20 net wells and net recompletions in progress at September 30, 2013.We also sold our Robinson’s Bend Field assets in the Black Warrior Basin of Alabama for net proceeds of approximately $59.0 million after customary costs and working capital adjustments and received $0.1 million in distributions from an equity affiliate.

Our cash capital expenditures were $10.4 million for the nine months ended September 30, 2012, which primarily consisted of development expenditures in the Cherokee Basin. We completed 28 net wells and 34 net recompletions during the first nine months of 2012 and had 55 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.

Financing Activities

Our net cash used by financing activities was $34.4 million for the nine months ended September 30, 2013, compared to $10.2 million used by financing activities for the same period in 2012. During the first nine months of 2013, we used $50.2 million of cash 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 September 30, 2013, we had approximately $0.9 million in debt issue costs remaining to be amortized over the life our reserve-based credit facility.

Our net cash used by financing activities was $10.2 million for the nine months ended September 30, 2012. We paid $10 million of our debt outstanding and used $0.2 million to fund the cost of units tendered by employees for tax withholdings for unit-based compensation.

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 September 30, 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 September 30, 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 September 30, 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 September 30, 2013, we have no past due receivables from ONEOK.

Derivative Counterparties

As of September 30, 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 September 30, 2013, each of these financial institutions has an investment grade credit rating.

Reserve-Based Credit Facility

As of September 30, 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 November 14, 2013, each of these financial institutions has an investment grade credit rating.

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 with a significant portion of this production level 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.

•Our cost reduction strategies to result in a general and administrative expense run rate of $12.4 million in 2013, with opportunities available to save another $0.6 million in 2014.

•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 September 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

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 November 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 September 30, 2013	$ 16,600	$ 6,336	$ (10,264)	$ 26,864	$ 10,264

Interest Rate Risk

At September 30, 2013, the one-month LIBOR rate was 0.18%, the three-month LIBOR rate was 0.25%, and our applicable margin on LIBOR borrowings was 3.50%. At September 30, 2013, the ABR rate was 3.25%, and our applicable margin on ABR borrowings was 2.50%. At September 30, 2013, we had debt outstanding of $50.7 million, all of which incurred interest at a one-month LIBOR rate plus an applicable margin of 3.50% based on utilization. We had no debt outstanding at the ABR rate. At September 30, 2013, the carrying value and fair value of our debt was $50.7 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 November 14, 2013, we had no interest rate derivatives.

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 September 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 September 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

On August 30, 2013, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPM, Gary M. Pittman and John R. Collins against the Company, certain of its officers and managers, SOG and SEP I in connection with the Company's closing on August 9, 2013 of the purchase of oil and gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contend, among other things, that the issuance of the units to SEP I in connection with the acquisition was not permitted under the Company's operating agreement, that Messrs. Pittman and Collins should not have been removed as the Class A managers of the Company's board of managers, and that SEP I, SOG and our current Class A managers participated in the bad faith conduct of the other defendants and interfered with CEPM's contractual rights under the Company's operating agreement. The plaintiffs allege claims against the Company and certain of its managers and officers relating to breach of contract, breach of the duty of good faith, and breach of the implied covenant of good faith and fair dealing; the plaintiffs also allege aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs seek, among other things, declaratory relief reappointing Messrs. Pittman and Collins to the Company's board of managers and removing our current Class A managers therefrom, and an injunction against the Company taking any further action outside the ordinary course of business during the pendency of the litigation, declaratory relief rescinding the units issued by the Company to SEP I, declaratory relief that CEPM has sole voting power with respect to the outstanding Class A units, declaratory relief that the Company's officers and managers have breached fiduciary and contractual duties and are not entitled to indemnification from the Company as a result thereof, and monetary damages. The lawsuit is currently in the discovery phase with a hearing on the plaintiff's application for an injunction seeking to enjoin the Company's December 5, 2013 annual meeting of unitholders scheduled for December 2, 2013, and the trial scheduled for

December 16, 17 and 18 in Wilmington, Delaware. The Company believes that the allegations contained in the lawsuit are without merit and intends to vigorously defend itself and its officers and managers against the claims raised in the complaint.

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.

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 and the outcome of litigation arising from the transaction.

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,” “anticipate,” “believe,” “estimate,” “pred “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 September 30, 2013 and December 31, 2012

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

Condensed Consolidated Statements of Cash Flows – Constellation Energy Partners LLC for the nine months ended September 30, 2013 and September 30, 2012

Condensed Consolidated Statements of Changes in Members' Equity – Constellation Energy Partners LLC for the nine months ended September 30, 2013

Notes to Condensed Consolidated Financial Statements

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EXHIBIT INDEX

Exhibit Number	Description
*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

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: November 14, 2013	By	/s/ Charles C. Ward Charles C. Ward Principal Financial Officer and Principal Accounting Officer

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