Constellation Energy Partners LLC
Form 10-Q
August 14, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

OR

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

For the transition period from to .

Commission File Number 001-33147

Constellation Energy Partners LLC

(Exact Name of Registrant as Specified in Its Charter)

Delaware	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 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 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

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

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

Common Units outstanding on August 11, 2014: 28,734,396 units.

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues				
Natural gas sales	$ 6,575	$ 10,025	$ 12,599	$ 11,417
Oil and liquids sales	5,514	5,363	11,231	9,071
Total revenues (See Note 5)	12,089	15,388	23,830	20,488
Expenses:				
Operating expenses:				
Lease operating expenses	5,182	3,905	10,302	8,141
Cost of sales	434	379	794	799
Production taxes	995	622	1,767	1,109
General and administrative	5,591	3,737	9,162	8,141
Gain on sale of assets	(16)	(17)	(23)	(23)
Depreciation, depletion and amortization	4,320	4,767	8,370	9,565
Asset impairments	45	-	194	-
Accretion expense	150	123	300	246
Total operating expenses	16,701	13,516	30,866	27,978
Other expenses (income)				
Interest expense	533	864	1,058	2,216
Other income	(134)	(104)	(144)	(172)
Total other expenses	399	760	914	2,044
Total expenses	17,100	14,276	31,780	30,022
Income (loss) from continuing operations	(5,011)	1,112	(7,950)	(9,534)
Loss from discontinued operations	-	-	-	(2,686)
Net income (loss)	$ (5,011)	$ 1,112	$ (7,950)	$ (12,220)
Earnings (loss) per unit (See Note 2)				
Earnings (loss) from continuing operations per unit				
Class A units - Basic and diluted	$ (0.21)	$ 0.05	$ (0.15)	$ (0.39)

Class B units - Basic and diluted	$ (0.17)	$ 0.05	$ (0.28)	$ (0.40)
Loss from discontinued operations per unit				
Class A units - Basic and diluted	$ -	$ -	$ -	$ (0.11)
Class B units - Basic and diluted	$ -	$ -	$ -	$ (0.11)
Net earnings (loss) per unit				
Class A units - Basic and diluted	$ (0.21)	$ 0.05	$ (0.15)	$ (0.50)
Class B units - Basic and diluted	$ (0.17)	$ 0.05	$ (0.28)	$ (0.51)
Weighted Average Units Outstanding				
Class A units - Basic	484,505	484,370	1,046,638	484,383
Class B units - Basic	28,305,380	23,345,280	28,259,994	23,306,269
Class A units - Diluted	484,505	484,370	1,046,638	484,383
Class B units - Diluted	28,305,380	23,720,732	28,259,994	23,306,269
Distributions declared and paid per unit	$ -	$ -	$ -	$ -

See accompanying notes to condensed consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,437	$ 4,894
Restricted cash (See Note 2)	1,748	-
Accounts receivable, net (See Note 2)	10,056	6,678
Prepaid expenses	1,275	2,547
Risk management assets (See Note 5)	4,041	9,141
Total current assets	21,557	23,260
Oil and natural gas properties (See Note 6)		
Oil and natural gas properties, equipment and facilities	643,678	639,156
Material and supplies	1,057	1,054
Less accumulated depreciation, depletion, amortization, and impairments	(503,436)	(495,215)
Net oil and natural gas properties	141,299	144,995
Other assets		
Debt issue costs (net of accumulated amortization of $9,012 and $9,003, respectively)	833	824
Risk management assets (See Note 5)	131	1,461
Restricted cash (See Note 2)	-	1,748
Other non-current assets	1,987	2,245
Total assets	$ 165,807	$ 174,533
LIABILITIES AND MEMBERS’ EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 627	$ 12
Accrued liabilities	8,031	12,763
Royalty payable	1,338	1,242
Risk management liabilities (see Note 5)	2,641	-
Total current liabilities	12,637	14,017
Other liabilities		
Asset retirement obligation	9,919	9,513
Risk management liabilities (see Note 5)	1,841	-
Other non-current liabilities	-	1,398

Debt (See Note 7)	51,950	50,700
Total other liabilities	63,710	61,611
Total liabilities	76,347	75,628
Commitments and contingencies (See Note 9)		
Members’ equity		
Class A units, 484,505 and 1,615,017 units authorized, issued and outstanding, respectively	1,581	2,591
Class B units, 28,848,785 and 28,848,785 units authorized, respectively, and 28,833,202 and 28,462,185 issued and outstanding, respectively	87,879	96,314
Total members’ equity	89,460	98,905
Total liabilities and members’ equity	$ 165,807	$ 174,533

See accompanying notes to condensed consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(Unaudited)

	Six months ended June 30, 2014	2013
Cash flows from operating activities:		
Net loss	$ (7,950)	$ (12,220)
Adjustments to reconcile net loss to cash provided by operating activities		
Depreciation, depletion and amortization	8,370	9,565
Asset impairments (See Note 6)	194	-
Amortization of debt issuance costs	127	1,178
Accretion expense	300	246
Equity earnings in affiliate	(70)	(172)
Gain from disposition of property and equipment	(23)	(23)
Bad debt expense	112	15
Mark-to-market on derivatives:		
Total (gains) losses	8,805	(776)
Cash settlements	2,107	4,066
Unit-based compensation programs	1,130	609
Discontinued operations	-	2,686
Changes in Assets and Liabilities:		
(Increase) decrease in accounts receivable	(3,489)	1,160
(Increase) decrease in prepaid expenses	1,272	(77)
(Increase) decrease in other assets	2	(1,149)
Increase in accounts payable	615	101
Decrease in accrued liabilities	(4,174)	(1,391)
Increase (decrease) in royalty payable	96	(45)
Increase (decrease) in other liabilities	(1,398)	1,139
Net cash provided by continuing operations	6,026	4,912
Net cash provided by discontinued operations	-	1,062
Net cash provided by operating activities	6,026	5,974
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(1,351)	(130)
Development of oil and natural gas properties	(3,819)	(6,319)
Proceeds from sale of assets	58	58,987

Distributions from equity affiliate	140	95
Net cash provided by (used in) continuing operations	(4,972)	52,633
Net cash used in discontinued operations	-	-
Net cash provided by (used in) investing activities	(4,972)	52,633
Cash flows from financing activities:		
Proceeds from issuance of debt	5,750	194
Repayment of debt	(4,500)	(50,194)
Repurchase of Class A, Class C and Class D interests	(2,468)	-
Units tendered by employees for tax withholdings	(157)	(185)
Debt issue costs	(136)	(840)
Net cash used in continuing operations	(1,511)	(51,025)
Net cash used in discontinued operations	-	-
Net cash used in financing activities	(1,511)	(51,025)
Net increase (decrease) in cash and cash equivalents	(457)	7,582
Cash and cash equivalents, beginning of period	4,894	1,959
Cash and cash equivalents, end of period	$ 4,437	$ 9,541
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ (542)	$ (351)
Cash paid during the period for interest	$ (950)	$ (1,012)

See accompanying notes to 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, 2013	1,615,017	$ 2,591	28,462,185	$ 96,314	$ -	$ 98,905
Distributions	-	-	-	-	-	-
Units tendered by employees for tax withholding	-	-	(62,683)	(157)	-	(157)
Unit-based compensation programs	-	-	433,700	1,130	-	1,130
Cancellation of units (See Note 9)	(1,130,512)	(851)	-	(1,617)	-	(2,468)
Net loss	-	(159)	-	(7,791)	-	(7,950)
Balance, June 30, 2014	484,505	$ 1,581	28,833,202	$ 87,879	$ -	$ 89,460

See accompanying notes to condensed consolidated financial statements.

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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". 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.

Through subsidiaries, Sanchez Oil & Gas Corporation (SOG) and PostRock Energy Corporation (NASDAQ: PSTR) (PostRock) own a portion of our outstanding units. As of June 30, 2014, Sanchez Energy Partners I, LP (SEP I), a subsidiary of SOG, owned 484,505, or 100%, of our Class A units and 5,139,345, or 17.8%, of our Class B common units. As of June 30, 2014, Constellation Energy Partners Management, LLC (CEPM), a subsidiary of PostRock, owned 4,282,500, or 14.9%, of our Class B common units.

On June 26, 2014, we settled the lawsuit brought by Constellation Energy Partners Holdings, LLC (CEPH), a subsidiary of Exelon Corporation, against us in the Court of Chancery of the State of Delaware (the Exelon Litigation). In conjunction with the settlement, we paid CEPH $1.65 million in exchange for all of the Class C management incentive interests and Class D interests held by CEPH, which were all of such interests issued by CEP. Effective with the acquisition of these interests from CEPH, we cancelled the Class C management incentive interests and Class D interests.

On May 8, 2014, the Company and SP Holdings, LLC (the Manager), an affiliate of SOG, entered into a Shared Services Agreement (the Services Agreement) pursuant to which, as of July 1, 2014, the Manager provides services that the Company requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services.

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, 2013, which was filed with the SEC on March 27, 2014.

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 on-going 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 reclassifications have been made to the prior period to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, total unitholders' equity, net income or net cash provided by or used in operating, investing or financing activities.

Discontinued Operations

In February 2013, we sold all of our Robinson's Bend Field assets in the Black Warrior Basin in Alabama. The related results of operations and cash flows have been classified as discontinued operations in the condensed consolidated statements of operations, balance sheets, statements of cash flows and consolidated financial information for the six months ended June 30, 2013. Unless otherwise indicated, information presented in the Notes to Condensed Consolidated Financial Statements relates only to the Company's continuing operations. Information related to discontinued operations is included in Note 3. Acquisitions and Divestiture.

New Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board (the FASB), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not effective, will not have a material impact on our condensed consolidated financial statements upon adoption.

In April 2014, the FASB issued Accounting Standards Update (ASU) No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This guidance changes the definition of a discontinued operation to include only those disposals of components of an entity that represent a strategic shift that has or will have a major effect on an entity's operations and financial results. This guidance is effective prospectively for fiscal years beginning after December 15, 2014. The effects of this accounting standard on our financial position, results of operations and cash flows are not yet known.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606). This guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is not permitted. The guidance may be applied retrospectively to each prior period presented or retrospectively with the cumulative effect recognized as of the date of initial application. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

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, 2013.

Earnings per Unit

Basic earnings per unit (EPU) is computed by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. To determine net income (loss) allocated to each class of ownership (Class A and Class B), we first allocate net income (loss) in accordance with the amount of distributions made for the period by each class, if any. The remaining net income (loss) is allocated to each class with the Class A units receiving 2% and the Class B units receiving 98%.

As of June 30, 2014 and 2013, we had unvested restricted common units outstanding, which were considered dilutive securities. These units will be considered in the diluted weighted average common units outstanding number in periods of net income. In periods of net losses, these units are excluded for the diluted weighted average common unit outstanding number as they are not participating securities.

The following table presents our calculation of basic and diluted units outstanding for the periods indicated:

Three Months Ended June 30,	Six Months Ended June 30,

	2014	2013	2014	2013
Weighted average units outstanding during period:				
Class A units - Basic	484,505	484,370	1,046,638	484,383
Class B units - Basic	28,305,380	23,345,280	28,259,994	23,306,269
	28,789,885	23,829,650	29,306,632	23,790,652
Weighted average units outstanding during period:				
Class A units - Diluted	484,505	484,370	1,046,638	484,383
Class B units - Diluted	28,305,380	23,720,732	28,259,994	23,306,269
	28,789,885	24,205,102	29,306,632	23,790,652

At June 30, 2014, we had 503,556 Class B common units that were restricted unvested common units granted and outstanding. These units were excluded from the diluted weighted average common unit outstanding number.

The following table presents our basic and diluted loss per unit for the three months ended June 30, 2014 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (5,011)		
Distributions	-	$ -	$ -
Assumed net loss to be allocated	$ (5,011)	$ (100)	$ (4,911)
Basic and diluted loss per unit		$ (0.21)	$ (0.17)

The following table presents our basic and diluted earnings per unit for the three months ended June 30, 2013 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Income from continuing operations	$ 1,112		
Distributions	-	$ -	$ -
Assumed allocation of income from continuing operations	1,112	22	1,090
Discontinued operations	-	-	-
Assumed net income to be allocated	$ 1,112	$ 22	$ 1,090
Basic and diluted earnings from continuing operations per unit		$ 0.05	$ 0.05
Basic and diluted earnings from discontinued operations per unit		$ -	$ -
Basic and diluted earnings per unit		$ 0.05	$ 0.05

The following table presents our basic and diluted loss per unit for the six months ended June 30, 2014 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (7,950)		
Distributions	-	$ -	$ -
Assumed net loss to be allocated	$ (7,950)	$ (159)	$ (7,791)
Basic and diluted loss per unit		$ (0.15)	$ (0.28)

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The following table presents our basic and diluted loss per unit for the six months ended June 30, 2013 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (9,534)		
Distributions	-	$ -	$ -
Assumed allocation of loss from continuing operations	(9,534)	(191)	(9,343)
Discontinued operations	(2,686)	(54)	(2,632)
Assumed net loss to be allocated	$ (12,220)	$ (245)	$ (11,975)
Basic and diluted loss from continuing operations per unit		$ (0.39)	$ (0.40)
Basic and diluted loss from discontinued operations per unit		$ (0.11)	$ (0.11)
Basic and diluted loss per unit		$ (0.50)	$ (0.51)

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 June 30, 2014 and December 31, 2013.

Restricted Cash

Restricted cash, at June 30, 2014 and December 31, 2013, of $1.7 million was being held in escrow. Of this balance, $0.6 million is related to a vendor dispute, and will remain in the escrow account until the dispute has been resolved. The remaining amount of $1.1 million is related to the sale of our Robinson's Bend Field assets in the Black Warrior Basin of Alabama. These funds will remain in escrow for a period ending February 28, 2015, pending certain post-closing conditions. The restricted cash was classified as a non-current asset at December 31, 2013, but was reclassified to a current asset at June 30, 2014, based on the conditions of the cash held in the account.

Accounts Receivable, Net

Our accounts receivable are primarily from purchasers of oil and natural gas and counterparties to our financial instruments. Oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserves until substantially all collection efforts have been exhausted. At June 30, 2014 and December 31, 2013, we had an allowance for doubtful accounts receivable of $0.3 million and $0.1 million, respectively.

3. ACQUISITIONS AND DIVESTITURE

Sale of Robinson's Bend Field Assets

On February 28, 2013, we sold all of our Robinson's Bend Field assets in the Black Warrior Basin of Alabama for $63.0 million, subject to closing adjustments that amounted to approximately $4.0 million. We recorded a loss on the sale of approximately $3.1 million in the six months ended June 30, 2013. The sale of the Robinson's Bend Field assets was initiated to provide the financial flexibility necessary to support our efforts for pursuing opportunities and further developing our properties in the Mid-Continent region, as well as reducing our outstanding debt.

The following amounts relating to the Robinson's Bend Field assets have been reported as discontinued operations in the condensed consolidated statements of operations for the three and six months ended June 30, 2013 (in thousands):

	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Revenues	$ -	$ 2,304
Loss from discontinued operations	$ -	$ (2,686)

See Note 2 for information regarding earnings per unit, including earnings per unit data relating to loss from discontinued operations.

The condensed consolidated statements of cash flows reflect discontinued operations for the six months ended June 30, 2013.

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

On August 9, 2013, we acquired oil, natural gas and NGLs 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 represented 70.0% of the total Class A units outstanding as of such date, and 4,724,407 Class B units, which represented 16.6% of the total Class B units outstanding as of such date. 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 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	$ 31,497
Asset retirement obligation	(1,088)
Net assets acquired	$ 30,409

We accounted for our acquisition of oil and natural gas properties using the purchase method of accounting for business combinations, and therefore we 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 were based on inputs that were 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.

Pro Forma Information

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, 2013. 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, 2013, nor is such information indicative of any expected future results of operations.

(In thousands, except per unit data)	Pro Forma Three Months Ended June 30, 2013	Pro Forma Six Months Ended June 30, 2013
Revenue	$ 19,668	$ 29,316
Income (loss) from continuing operations	$ 3,179	$ (4,551)
Discontinued operations	$ -	$ (2,686)
Net income (loss)	$ 3,179	$ (7,237)
Income (loss) from continuing operations per unit		
Class A units - Basic and diluted	$ 0.04	$ (0.06)
Class B units - Basic and diluted	$ 0.11	$ (0.16)
Discontinued operations per unit		
Class A units - Basic and diluted	$ -	$ (0.03)
Class B units - Basic and diluted	$ -	$ (0.09)
Net income (loss) per unit		
Class A units - Basic and diluted	$ 0.04	$ (0.09)
Class B units - Basic and diluted	$ 0.11	$ (0.25)
Weighted average units outstanding		
Class A units - Basic	1,614,882	1,614,895
Class B units - Basic	28,069,687	28,030,676
Class A units - Diluted	1,614,882	1,614,895
Class B units - Diluted	28,445,139	28,030,676

Acquisition of Oil and Natural Gas Properties

On April 9, 2014, we acquired a 20% working interest in nine producing wells and other assets for $1.4 million. These assets are located in LaSalle Parish, Louisiana and are operated by SOG. This purchase became effective May 1, 2014. The impact of the acquisition of these properties was not material to our consolidated financial statements, so no pro forma information for this acquisition is provided.

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 June 30, 2014 (in thousands):

	Fair Value Measurements at June 30, 2014				
	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 June 30, 2014
Risk Management Assets	$ -	$ 4,473	$ -	$ (301)	$ 4,172
Risk Management Liabilities	-	(4,783)	-	301	(4,482)
Total Net Assets and Liabilities	$ -	$ (310)	$ -	$ -	$ (310)

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, 2013 (in thousands):

	Fair Value Measurements at December 31, 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 December 31, 2013
Risk Management Assets	$ -	$ 11,577	$ -	$ (975)	$ 10,602
Risk Management Liabilities	-	(975)	-	975	-
Total Net Assets and Liabilities	$ -	$ 10,602	$ -	$ -	$ 10,602

As of June 30, 2014, 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 not elected to designate any 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 June 30, 2014, 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
2014					1,610,000	$ 5.75	1,610,000	$ 5.75	3,220,000	$ 5.75
2015	1,215,420	$ 4.25	1,153,487	$ 4.25	1,096,023	$ 4.26	1,050,219	$ 4.26	4,515,149	$ 4.25
2016	1,010,633	$ 4.21	967,290	$ 4.21	923,541	$ 4.21	893,568	$ 4.22	3,795,032	$ 4.21
									11,530,181	

MTM Fixed Price Basis Swaps– Enable Gas Transmission, LLC (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 $
2014					1,084,270	$ 0.39	1,047,963	$ 0.39	2,132,233	$ 0.39
									2,132,233	

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
2014					74,482	$ 95.63	73,005	$ 95.78	147,487	$ 95.71
2015	69,479	$ 90.99	66,183	$ 91.02	63,025	$ 91.05	60,143	$ 91.09	258,830	$ 91.04
2016	57,420	$ 85.64	54,879	$ 85.64	52,474	$ 85.64	50,197	$ 85.64	214,970	$ 85.64
									621,287	

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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 June 30, 2014	December 31, 2013
Commodity – MTM	Risk management assets - current	$ 4,107	$ 10,043
Commodity – MTM	Risk management assets - non-current	366	1,534
	Total gross assets	4,473	11,577
Commodity – MTM	Risk management assets – current	(2,707)	(902)
Commodity – MTM	Risk management assets – non-current	(2,076)	(73)
	Total gross liabilities	(4,783)	(975)
	Total net assets and liabilities	$ (310)	$ 10,602

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 June 30, 2014	2013
Commodity – Mark-to-Market	Oil and natural gas sales	$ (4,730)	$ 5,422
Interest Rate – Mark-to-Market	Interest expense	-	(19)
	Total	$ (4,730)	$ 5,403

Derivative Type	Location of Gain/(Loss) in Income	Amount of Gain/(Loss) in Income For the Six Months Ended June 30, 2014	2013
Commodity – Mark-to-Market	Oil and natural gas sales	$ (8,805)	$ 842
Interest Rate – Mark-to-Market	Interest expense	-	(65)

Total	$ (8,805)	$ 777

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 June 30, 2014 and December 31, 2013, the impact of non-performance credit risk on the valuation of our net assets from counterparties was not significant, and the entire amount was reflected as a decrease to our non-cash mark-to-market gain, respectively.

Hedge Liquidation and Repositioning

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 per Mcf. These transactions ensured 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 per barrel, 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):

	June 30, 2014	December 31, 2013
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 641,468	$ 636,816
Unproved property	1,459	1,589
Total property costs	642,927	638,405
Materials and supplies	1,057	1,054
Land	751	751
Total	644,735	640,210
Less: Accumulated depreciation, depletion, amortization and impairments	(503,436)	(495,215)
Oil and natural gas properties and equipment, net	$ 141,299	$ 144,995

Depreciation, depletion, amortization and impairments consisted of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
DD&A of oil and natural gas-related assets	$ 4,320	$ 4,767	$ 8,370	$ 9,565
Asset Impairments	45	-	194	-

Total	$ 4,365	$ 4,767	$ 8,564	$ 9,565

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

For the six months ended June 30, 2014, our non-cash impairment charges were approximately $0.1 million to impair the value of our oil and natural gas fields in Texas and Louisiana, with an immaterial amount being recorded during the three months ended June 30, 2014. For the three and six months ended June 30, 2013, we did not have an impairment to record. The 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.

Asset Sales

During each of the three and six months ended June 30, 2014 and June 30, 2013, we sold miscellaneous surplus equipment for less than $0.1 million resulting in an immaterial gain on the asset sales.

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Useful Lives

Our furniture, fixtures and equipment are depreciated over a life of one to seven years, buildings are depreciated over a life of 20 years and pipeline and gathering systems are depreciated over a life of 25 to 40 years.

Exploration and Dry Hole Costs

We recorded no exploration and dry hole costs for the three and six months ended June 30, 2014 and 2013, respectively. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs and the impairment, amortization and abandonment associated with leases on our unproved properties.

7. DEBT

Reserve-Based Credit Facility

In May 2013, we refinanced our $350.0 million reserve-based credit facility with Societe Generale as administrative and collateral agent and a syndicate of lenders, extending its maturity to May 30, 2017 and increasing our borrowing base from $37.5 million to $55.0 million. On May 6, 2014, our borrowing base under the reserve-based credit facility was increased to $70.0 million. 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 amount available for borrowing at any one time under the reserve-based credit facility is limited to the borrowing base for our oil and natural gas properties. As of June 30, 2014, we had borrowed $52.0 million under our reserve-based credit facility and our borrowing base was $70.0 million. At June 30, 2014, the lenders and their percentage commitments in the reserve-based credit facility were Societe Generale (36.36%), OneWest Bank, FSB (36.36%) and BOKF NA, dba Bank of Oklahoma (27.28%).

Borrowings under the reserve-based credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the reserve-based credit facility, working capital and general limited liability company purposes. The reserve-based credit facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit. As of June 30, 2014, no letters of credit were outstanding.

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 is 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, as discussed below, and the interest rate on our borrowings.

In addition, we are required to maintain (i) a ratio of Total Net Debt (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents and cash reserves of the Company)) to Adjusted EBITDA (generally, for any period, the sum of consolidated net income for such period plus (minus) the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives and other similar charges) of not more than 3.5 to 1.0; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under Accounting Standards Codification (ASC) Topic 815, Derivatives and Hedging; ASC Topic 410, Asset Retirement and Environmental Obligations and ASC Topic 360, Property, Plant and Equipment. All financial covenants are calculated using our consolidated financial information and are discussed below.

The reserve-based credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, guaranties not being valid under the reserve-based credit facility and a change of control. A change of control is generally defined as the occurrence of both of the following events: (i) wholly-owned subsidiaries of Constellation Energy Group, Inc. are the owner of 20% or less of an interest in us (which has now occurred) and (ii) any person or group of persons acting in concert are the owner of more than 35% of an interest in us. These events have not both occurred, so a change in control had not occurred as of June 30, 2014. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

The reserve-based credit facility limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of our borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business. As of June 30, 2014, 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.

The reserve-based credit facility permits us to hedge our projected monthly production, provided that (a) for the immediately ensuing twelve-month period, the volumes of production hedged in any month may not exceed our reasonable business judgment of the production for such month consistent with the application of petroleum engineering methodologies for estimating proved developed producing reserves based on the then-current strip pricing (provided that such projection shall not be more than 115% of the proved developed producing reserves forecast for the same period derived from the most recent reserve report of our petroleum engineers using the then strip pricing), and (b) for the period beyond twelve months, the volumes of production hedged in any month may not exceed the reasonably anticipated projected production from proved developed producing reserves estimated by our petroleum engineers. The reserve-based credit facility also permits us to hedge the interest rate on up to 90% of the then-outstanding principal amounts of our indebtedness for borrowed money.

The reserve-based credit facility contains no covenants related to SOG's or PostRock's ownership in us.

Compliance with Debt Covenants

At June 30, 2014, we were in compliance with the financial covenants contained in our reserve-based credit facility. We monitor compliance on an on-going basis.

If we are unable to remain in compliance with the financial covenants contained in our reserve-based credit facility or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of our reserve-based credit facility, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated covenants from the lenders, but there is no assurance that such waivers would be granted.

The amount available for borrowing at any one time under the reserve-based credit facility is limited to the borrowing base for our oil and natural gas properties. As of June 30, 2014, our borrowing base was $70.0 million. The borrowing base is re-determined semi-annually, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Funds Available for Borrowing

As of June 30, 2014 and December 31, 2013, we had $52.0 million and $50.7 million, respectively, in outstanding debt under our reserve-based credit facility. As of June 30, 2014, we had $18.0 million available under our reserve-based credit facility.

Debt Issue Costs

As of June 30, 2014, our unamortized debt issue costs were approximately $0.8 million. These costs are being amortized over the life of our reserve-based credit facility. At December 31, 2013, our unamortized debt issue costs were approximately $0.8 million.

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):

	June 30, 2014	December 31, 2013
Asset retirement obligation, beginning balance	$ 9,513	$ 7,665
Liabilities added from acquisitions	79	1,088
Liabilities added from drilling	27	244
Settlements	-	(3)
Accretion expense	300	519
Asset retirement obligation, ending balance	$ 9,919	$ 9,513

Additional asset retirement obligations increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset retirement obligations. At June 30, 2014 and December 31, 2013, 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 (the PostRock Litigation) in connection with the Company's closing on August 9, 2013 of the purchase of oil and natural gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contended, 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 bad faith conduct of the other defendants and interfered with CEPM's contractual rights under the Company's operating agreement. The plaintiffs alleged 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 alleged aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs sought, 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 had sole voting power with respect to the outstanding Class A units, declaratory relief that the Company's officers and managers breached fiduciary and contractual duties and were not entitled to indemnification from the Company as a result thereof, and monetary damages. On March 31, 2014, the parties to the lawsuit reached a settlement agreement and the lawsuit was subsequently dismissed. As a result of the settlement, the Class A units acquired by SEP I in the August 2013 transaction were returned to CEP and cancelled in exchange for $0.8 million; CEPM transferred 100% of its Class A units and 414,938 of CEP's Class B units to SEP I in exchange for an aggregate payment of $1.0 million from SEP I, and CEP paid $6.5 million to CEPM. In addition, pursuant to the terms of the settlement, CEPM agreed to sell its remaining Class B units over the next nine months, with SEP I providing up to a $5.0 million backstop payment to CEPM to the extent proceeds received by CEPM from such sale do not meet or exceed a specified amount. As a result of the settlement, the settling parties filed a stipulation in the Court of Chancery of the State of Delaware seeking to lift the preliminary injunction issued on December 3, 2013, and the litigation was dismissed with prejudice. The settlement also included mutual releases between the plaintiffs and defendants. In connection with the settlement, we received $1.25 million on April 10, 2014, under our directors and officers insurance policy.

On February 28, 2014, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPH against the Company (the Exelon Litigation) seeking repayment of suspended distributions in relation to the Class D Interests held by CEPH. In 2006, Constellation Holding, Inc (CHI), which merged with and into CEPH in December 2012, purchased the Company's Class D Interests for $8.0 million. The $8.0 million was to be repaid to CEPH in quarterly distributions of $333,333.33 over a period of six years; however, these distributions could be temporarily suspended if a dispute arose over pricing formulas related to the sale of natural gas from the Robinson's Bend properties. A dispute arose, so the distributions were suspended pursuant to the Company's operating agreement and never reinstated. CEPH contended, among other things, that the Company breached its contract to pay the quarterly distributions, acted in bad faith and received unjust enrichment by suspending the quarterly distributions. On June 26, 2014, the parties to the lawsuit reached a settlement agreement and the lawsuit was subsequently dismissed. In conjunction with the settlement, we paid CEPH $1.65 million in exchange for all of the Class C management incentive interests and the Class D interests held by CEPH, which accounted for all such interests issued by CEP. Effective with the acquisition from CEPH, we cancelled the Class C management incentive interests and Class D interests.

10. RELATED PARTY TRANSACTIONS

Unit Ownership

PostRock and SOG, through subsidiaries, own a portion of our outstanding units. As of June 30, 2014, CEPM, a subsidiary of PostRock, owned 4,282,500, or 14.9%, of our Class B common units. SEP I, a subsidiary of SOG, owned 484,505, or 100%, of our Class A units and 5,139,345, or 17.8%, of our Class B common units as of June 30, 2014.

PostRock-Related Announcements

In 2011, PostRock acquired certain of our Class A units and Class B common units in two separate transactions. Approval of the purchase of these units was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an "interested unitholder" under Section 203 of the Delaware General Corporation Law, which is applicable to us pursuant to our operating agreement. Section 203, as it applies to us, prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66 2/3% of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines "business combination" to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our operating agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units. We believe the Section 203 restrictions related to these unit purchases expire in December 2014. At June 30, 2014, PostRock's investment in us represented a 14.6% ownership interest.

Sanchez-Related Announcements

In August 2013, SOG acquired certain of our Class A units and Class B common units and one Class Z unit in one transaction which represented a 19.2% ownership interest in us at June 30, 2014. These units were issued to SOG, along with cash, in exchange for oil and natural gas properties located in Texas and Louisiana.

In August 2013, the Company also entered into a Registration Rights Agreement with SOG pursuant to which the Company granted to SOG certain registration rights related to the unit consideration thereunder. Under the Registration Rights Agreement, the Company granted SOG demand registration rights with respect to the preparation and filing with the SEC of one or more registration statements for the purpose of registering the resale of the securities that will be registered.

On May 8, 2014, the Company and the Manager, an affiliate of SOG, entered into the Services Agreement pursuant to which the Manager provides services that the Company requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services. In connection with providing the services under the Services Agreement, the Manager receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of the Company's properties other than its assets located in the Mid-Continent region, (ii) a $1,000,000 administrative fee, with $500,000 paid on May 8, 2014 and $500,000 paid on July 1, 2014, the date that the Manager provided notice of its commitment to provide services under the Services Agreement (the In-Service Date), (iii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iv) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Each of these fees, not including the reimbursement of costs, will be paid in cash unless the Manager elects for such fee to be paid in equity by the Company. In addition, upon the first acquisition of assets from an affiliate of the Manager, the Company is required to amend its operating agreement and issue a new class of incentive distribution right to the Manager.

The Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless both the Manager and the Company provide notice to terminate the agreement. The Services Agreement can be terminated early (i) by either party at any time after 24 months from the In-Service Date with six months' notice to the other party, (ii) by either party if there is an uncured material breach thereunder by the other party or (iii) by the Company if there is a change in control of the Manager and the Company pays the termination payment discussed below. If there is a termination of the Services Agreement other than by either party at the end of the agreement's term or by the Company for a breach by the Manager, then the Company will owe a termination payment to the Manager equal to $5,000,000, plus 5% of the transaction value of all asset acquisitions theretofore consummated; if the Company terminates after the 24-month anniversary of the In-Service Date upon six months' notice, the Company will also owe to the Manager all costs and expenses of the Manager that result from such termination.

On May 8, 2014, the Company and SOG entered into a Contract Operating Agreement (the Operating Agreement) pursuant to which SOG has agreed either to provide services to operate, develop and produce the Company's oil and natural gas properties or to engage a third-party operator to do so, other than with respect to the Company's properties in the Mid-Continent region. In connection with providing services under the Operating Agreement, SOG will be reimbursed for all direct charges under COPAS.

On May 8, 2014, the Company, the Manager and SOG entered into a Transition Agreement (the Transition Agreement) pursuant to which the Company agreed to make available to the Manager and SOG certain of the Company's employees for SOG or the Manager to provide services under the Services Agreement and Operating agreement. No compensation was paid by any party for the provision or use of employees under the Transition Agreement. All employees remained under the day-to-day control of the Company, and the Company retained the right to terminate employees and had no obligation to hire new employees. SOG had the right to hire any Company employees and thereafter, SOG is responsible for all costs and expenses for such employees. As of the In-Service Date, all employees of the Company located in the Houston office became employees of SOG, except for the Chief Executive Officer and the Chief Financial Officer, who remain employees of the Company.

On May 8, 2014, the Company, SOG and certain subsidiaries of the Company entered into a Geophysical Seismic Data Use License Agreement (the License Agreement) pursuant to which SOG provides to the Company a non-exclusive, royalty-free license to use seismic, geophysical and geological information relating to the Company's oil and natural gas properties that is proprietary to SOG and not restricted by agreements that SOG has with landowners or seismic data vendors.

Class C Management Incentive Interests

CEPH, a subsidiary of Exelon, held the Class C management incentive interests in CEP. These management incentive interests represented the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our operating agreement) had been achieved and certain other tests had been met. In conjunction with the settlement of the Exelon Litigation, we acquired all of the Class C management incentive interests from CEPH and the interests were cancelled.

Class D Interest

CEPH, a subsidiary of Exelon and successor to CHI, held all of our Class D interests. Due to the contingently redeemable feature, the Class D interests were treated as temporary equity until June 2009, when distributions were suspended. Accordingly, the Class D interests were moved from temporary equity to permanent equity (Class A and Class B) in the fourth quarter of 2011. In conjunction with the settlement of the Exelon Litigation, we acquired all of the Class D interests from CEPH and the interests were cancelled.

Class Z Unit

SOG holds the one Class Z unit of CEP. This one unit is a non-voting unit, except for voting as a separate class to approve the issuance of additional Company securities, other than Class B common units, prior to the issuance of such securities. The Class Z unit is a non-economic interest, without any right to participate in distributions or allocations.

11. UNIT-BASED COMPENSATION

We have the following unit-based compensation plans:

We have the 2009 Omnibus Incentive Compensation Plan (Omnibus Plan), which is a plan under which restricted common unit awards are granted to certain employees in Texas. The Omnibus Plan provides for a variety of unit-based and performance-based awards, including unit options, restricted units, unit grants, notional units, unit appreciation rights, performance awards and other unit-based awards. Awards under the Omnibus Plan may be paid in cash, units or any combination thereof as determined by the compensation committee of our board of managers.

Restricted unit activity (number of units) under the Omnibus Plan was as follows:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2013	336,551	$ 3.29
Vested	(171,692)	3.33
Granted	-	-
Returned/Cancelled	(57,214)	3.33
Outstanding at March 31, 2014	107,645	3.20
Vested	(37,653)	2.44
Granted	346,403	2.44
Returned/Cancelled	(15,981)	3.44
Outstanding at June 30, 2014	400,414	$ 2.39

We have the Long-Term Incentive Plan (L-TIP), which is a plan under which restricted common unit awards are granted to certain field employees in Alabama, Kansas and Oklahoma and to certain employees in Texas.

Restricted unit activity (number of units) under the L-TIP Plan was as follows:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2013	43,776	$ 2.87
Vested	(16,415)	2.87
Granted	-	-
Returned/Cancelled	(5,469)	2.87
Outstanding at March 31, 2014	21,892	2.87
Vested	(22,028)	2.44
Granted	103,278	2.44
Returned/Cancelled	-	-
Outstanding at June 30, 2014	103,142	$ 2.53

We recognized approximately $1.1 million and $0.6 million of non-cash compensation expense related to our unit-based compensation plans in the six months ended June 30, 2014 and June 30, 2013, respectively.

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

2014 Equity

At June 30, 2014, we had 484,505 Class A units and 28,833,202 Class B common units outstanding, which included 103,142 unvested restricted common units issued under our L-TIP Plan and 400,414 unvested restricted common units issued under our Omnibus Plan.

At June 30, 2014, we had granted 444,543 common units of the 450,000 common units available under our L-TIP Plan. Of these grants, 341,401 have vested.

At June 30, 2014, we had granted 1,639,874 common units of the 1,650,000 common units available under our Omnibus Plan. Of these grants, 1,239,460 have vested.

For the six months ended June 30, 2014, 62,683 common units were tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, were returned to their respective plan and are available for future grants.

2013 Equity

At December 31, 2013, we had 1,615,017 Class A units and 28,462,185 Class B common units outstanding, which included 43,776 unvested restricted common units issued under our L-TIP Plan and 336,551 unvested restricted common units issued under our Omnibus Plan.

At December 31, 2013, we had granted 346,734 common units of the 450,000 common units available under our L-TIP Plan. Of these grants, 302,958 have vested.

At December 31, 2013, we had granted 1,366,666 common units of the 1,650,000 common units available under our Omnibus Plan. Of these grants, 1,030,115 have vested.

For the three months ended December 31, 2013, 139,810 common units were tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, were returned to their respective plan and are available for future grants.

14. SUBSEQUENT EVENTS

We evaluated subsequent events through the time of filing this Quarterly Report on Form 10-Q. No significant events occurred subsequent to the balance sheet or prior to the filing of this report that would have a material impact on our condensed 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 "SOG" and "SEP I" are to Sanchez Oil & Gas Corporation and its subsidiary, Sanchez Energy Partners I, LP, respectively. References in this Quarterly Report on Form 10-Q to "PostRock" and "CEPM" are to PostRock Energy Corporation and its subsidiary, Constellation Energy Partners Management, LLC, respectively. References in this Quarterly Report on Form 10-Q to "Exelon" and "CEPH" are to Exelon Corporation and its subsidiary, Constellation Energy Partners Holdings, LLC, respectively.

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;

•asset impairments;

•accretion expense;

•(gain) loss on sale of assets;

•unit-based compensation programs;

•gain on mark-to-market activities;

•loss on mark-to-market activities; and

•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 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 June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$ (5,011)	$ 1,112	$ (7,950)	$ (12,220)
Adjusted by:				
Interest expense, net	533	864	1,058	2,216
Depreciation, depletion and amortization	4,320	4,767	8,370	9,565
Asset impairments	45	—	194	—
Accretion expense	150	123	300	246
Gain on sale of assets	(16)	(17)	(23)	(23)
Unit-based compensation programs	1,029	208	1,130	609
Gain on mark-to-market activities	(111)	(2,346)	(251)	(1,238)
Loss on mark-to-market activities	6,026	—	11,163	8,177
Loss on discontinued operations	—	—	—	2,686
Adjusted EBITDA	$ 6,965	$ 4,711	$ 13,991	$ 10,018

Our Adjusted EBITDA from our continuing operations was $7.0 million for the three months ended June 30, 2014, which is higher than our Adjusted EBITDA of $4.7 million in the same period in 2013. The increase is the result of increased oil and natural gas production due to the Texas and Louisiana acquired properties and higher natural gas prices during 2014.

Our Adjusted EBITDA was $14.0 million for the six months ended June 30, 2014, higher than our Adjusted EBITDA of $10.0 million in the same period in 2013. The increase is the result of increased oil and natural gas production due to the Texas and Louisiana acquired properties and higher natural gas prices during 2014.

During 2014, 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 for 2014 of $20 million to $22 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 prices for the six months ended June 30, 2014, were $5.56 per Mcfe for natural gas and $84.75 per barrel for oil, including hedge settlements and $4.80 per Mcf for natural gas and $87.42 per barrel for oil, excluding hedge settlements. After deducting the cost of sales associated with our third party gathering, our average realized prices were $5.33 per Mcf for natural gas and $80.48 per barrel for oil, including hedge settlements and $4.57 per Mcf for natural gas and $83.15 per barrel for oil, excluding hedge settlements.

- Production. Our production for the six months ended June 30, 2014, was 4.5 Bcfe, or an average of 25,028 Mcfe per day, compared with approximately 3.9 Bcfe, or an average of 21,322 Mcfe per day, for the six months ended June 30, 2013. Our oil production increased 105.4% for the six months ended June 30, 2014 when compared to the same period in 2013.

Our 2014 production was higher than the production for the same period in 2013 because of the increase in oil and natural gas production due to the Texas and Louisiana acquired properties and higher market prices for natural gas.

- Capital Expenditures and Drilling Results. During the first six months of 2014, we spent approximately $5.2 million in cash capital expenditures, consisting of $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $2.3 million in development expenditures focused on oil completions in the Cherokee Basin and $1.5 million in development expenditures focused on properties in Texas and Louisiana. We completed four net wells and four net recompletions during the six months ended June 30, 2014 and had one net well and net recompletion in progress at June 30, 2014. During the first six months of 2014, our daily average net oil and liquids production increased to 1,041 barrels from our average daily net production of 500 barrels for the same period during 2013.

- Hedging Activities. All of our commodity derivatives are accounted for as mark-to-market activities. For the six months ended June 30, 2014, the non-cash mark-to-market loss for our commodity derivatives was approximately $10.9 million, compared to a non-cash mark-to-market loss of $6.9 million for the same period in 2013.

- Debt Reduction. We reduced our outstanding debt from a high of $220.0 million in 2009 to $52.0 million as of June 30, 2014. At June 30, 2014, we had $52.0 million in outstanding debt and $18.0 million in unused borrowing capacity under our reserve-based credit facility.

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 Six Months Ended			
	June 30, 2014	2013	Variance $	%	June 30, 2014	2013	Variance $	%
Revenues:								
Natural gas sales at market price	$ 6,346	$ 5,228	$ 1,118	21.4%	$ 14,769	$ 9,619	$ 5,150	53.5%
Natural gas hedge settlements	1,596	2,730	(1,134)	(41.5%)	2,603	7,274	(4,671)	(64.2%)
Natural gas mark-to-market activities	(2,232)	1,352	(3,584)	(265.1%)	(6,406)	(7,129)	723	10.1%
Natural gas total	5,710	9,310	(3,600)	(38.7%)	10,966	9,764	1,202	12.3%
Oil and liquids sales	9,609	4,023	5,586	138.9%	16,233	8,374	7,859	93.9%
Oil hedge settlements	(412)	346	(758)	(219.1%)	(496)	507	(1,003)	(197.8%)
Oil mark-to-market activities	(3,683)	994	(4,677)	(470.5%)	(4,506)	190	(4,696)	(2,471.6%)

Oil and liquids total	5,514	5,363	151	2.8%	11,231	9,071	2,160	23.8%
Miscellaneous income	865	715	150	21.0%	1,633	1,653	(20)	(1.2%)
Total revenues	12,089	15,388	(3,299)	(21.4%)	23,830	20,488	3,342	16.3%
Operating expenses:								
Lease operating expenses	5,182	3,905	1,277	32.7%	10,302	8,141	2,161	26.5%
Cost of sales	434	379	55	14.5%	794	799	(5)	(0.6%)
Production taxes	995	622	373	60.0%	1,767	1,109	658	59.3%
General and administrative	5,591	3,737	1,854	49.6%	9,162	8,141	1,021	12.5%
Gain on sale of assets	(16)	(17)	1	5.9%	(23)	(23)	-	0.0%
Depreciation, depletion and amortization	4,320	4,767	(447)	(9.4%)	8,370	9,565	(1,195)	(12.5%)
Asset impairments	45	-	45	100.0%	194	-	194	100.0%
Accretion expenses	150	123	27	22.0%	300	246	54	22.0%
Total operating expenses	16,701	13,516	3,185	23.6%	30,866	27,978	2,888	10.3%
Other expenses (income):								
Interest expense	533	1,848	(1,315)	(71.2%)	1,058	5,864	(4,806)	(82.0%)
Interest income-Gain from mark-to-market activities	-	(984)	984	100.0%	-	(3,648)	3,648	100.0%
Other income	(134)	(104)	(30)	(28.8%)	(144)	(172)	28	16.3%
Total other expenses	399	760	(361)	(47.5%)	914	2,044	(1,130)	(55.3%)
Total expenses	17,100	14,276	2,824	19.8%	31,780	30,022	1,758	5.9%
Loss on discontinued operations	-	-	-	0.0%	-	(2,686)	2,686	100.0%
Net income (loss)	$ (5,011)	$ 1,112	$ (6,123)	(550.6%)	$ (7,950)	$ (12,220)	$ 4,270	34.9%

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	For the Three Months Ended June 30, 2014	2013	Variance $	%	For the Six Months Ended June 30, 2014	2013	Variance $	%
Net production:								
Natural gas production (MMcf)	1,675	1,593	82	5.1%	3,416	3,316	100	3.0%
Oil and liquids production (MBbl)	104	43	61	143.7%	186	90	96	106.5%
Total production (MMcfe)	2,300	1,849	451	24.4%	4,530	3,859	671	17.4%
Average daily production (Mcfe/d)	25,271	20,315	4,955	24.4%	25,028	21,322	3,706	17.4%
Total production (MBOE)	383	308	75	24.4%	755	643	112	17.4%
Average daily production (BOE/d)	4,212	3,386	826	24.4%	4,171	3,553	618	17.4%
Average sales prices:								
Natural gas price per Mcf with hedge settlements	$ 5.26	$ 5.45	$ (0.19)	(3.5%)	$ 5.56	$ 5.59	$ (0.03)	(0.5%)
Natural gas price per Mcf without hedge settlements	$ 4.30	$ 3.73	$ 0.57	15.3%	$ 4.80	$ 3.40	$ 1.40	41.2%
Oil and liquids price per Bbl with hedge settlements	$ 88.40	$ 102.32	$ (13.92)	(13.6%)	$ 84.75	$ 98.24	$ (13.49)	(13.7%)
Oil and liquids price per Bbl without hedge settlements	$ 92.36	$ 94.22	$ (1.86)	(2.0%)	$ 87.42	$ 92.63	$ (5.21)	(5.6%)
Total price per Mcfe with hedge settlements	$ 7.83	$ 7.05	$ 0.78	11.1%	$ 7.67	$ 7.11	$ 0.56	7.9%
Total price per Mcfe without hedge settlements	$ 7.31	$ 5.39	$ 1.92	35.7%	$ 7.20	$ 5.09	$ 2.11	41.5%
Total price per BOE with hedge settlements	$ 46.97	$ 42.33	$ 4.64	11.0%	$ 46.01	$ 42.65	$ 3.36	7.9%
Total price per BOE without hedge settlements	$ 43.89	$ 32.34	$ 11.55	35.7%	$ 43.22	$ 30.55	$ 12.67	41.5%
Average unit costs per Mcfe:								
Field operating expenses(a)	$ 2.69	$ 2.45	$ 0.24	9.7%	$ 2.66	$ 2.40	$ 0.26	10.7%
Lease operating expenses	$ 2.25	$ 2.11	$ 0.14	6.7%	$ 2.27	$ 2.11	$ 0.16	7.8%
Production taxes	$ 0.43	$ 0.34	$ 0.09	25.6%	$ 0.39	$ 0.29	$ 0.10	35.7%
General and administrative	$ 2.43	$ 2.01	$ 0.42	20.9%	$ 2.02	$ 2.11	$ (0.09)	(4.1%)
General and administrative w/o unit-based compensation	$ 1.98	$ 1.91	$ 0.07	3.9%	$ 1.77	$ 1.95	$ (0.18)	(9.2%)
Depreciation, depletion and amortization	$ 1.88	$ 2.58	$ (0.70)	(27.1%)	$ 1.85	$ 2.48	$ (0.63)	(25.5%)
Average unit costs per BOE:								
Field operating expenses(a)	$ 16.12	$ 14.69	$ 1.43	9.8%	$ 15.98	$ 14.38	$ 1.60	11.1%
Lease operating expenses	$ 13.52	$ 12.67	$ 0.85	6.7%	$ 13.64	$ 12.66	$ 0.98	7.8%
Production taxes	$ 2.60	$ 2.02	$ 0.58	28.6%	$ 2.34	$ 1.72	$ 0.62	35.7%

General and administrative	$ 14.59	$ 12.13	$ 2.46	20.3%	$ 12.13	$ 12.66	$ (0.53)	(4.2%)
General and administrative w/o unit-based compensation	$ 11.90	$ 11.45	$ 0.45	3.9%	$ 10.64	$ 11.72	$ (1.08)	(9.2%)
Depreciation, depletion and amortization	$ 11.27	$ 15.47	$ (4.20)	(27.1%)	$ 11.09	$ 14.87	$ (3.78)	(25.4%)

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

Three months ended June 30, 2014 compared to three months ended June 30, 2013

Oil and natural gas sales. Unhedged oil and liquid sales increased $5.6 million, or 138.9%, to $9.6 million for the three months ended June 30, 2014, compared to $4.0 million for the same period in 2013. Unhedged natural gas sales increased $1.1 million, or 21.4%, to $6.3 million for the three months ended June 30, 2014, compared to $5.2 million for the same period in 2013. With hedges and mark-to-market activities, our total revenue decreased $3.3 million, compared to the same period in 2013. Of this decrease, $1.9 million was attributable to lower cash hedge settlements from our hedge program and $8.3 million in lower mark-to-market activities, partially offset by $4.4 million attributable to higher market prices for our natural gas and oil production and $2.4 million in higher volume variance. Production for the three months ended June 30, 2014 was 2.3 Bcfe, which was 0.5 Bcfe higher than the same period in 2013. We hedged all of our production volumes sold through June 30, 2014, and the same through June 30, 2013. Oil production increased approximately 143.7% during the three months ended June 30, 2014, compared to the three months ended June 30, 2013, as a result of our acquisition and development of properties located in Texas and Louisiana.

Cash hedge settlements received for our commodity derivatives were approximately $1.2 million for the three months ended June 30, 2014. Cash hedge settlements received for our commodity derivatives were approximately $3.1 million for the three months ended June 30, 2013. This difference was due to changes in hedge prices, hedged volumes and market prices for natural gas and oil during 2013 and 2014.

As discussed below, our non-cash mark-to-market activities decreased by $8.3 million for the three months ended June 30, 2014, compared to the same period in 2013. Our realized prices before our hedging program increased from 2013 to 2014 primarily for natural gas production and decreased for oil production. These realized prices were impacted by our hedging program and the mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. All of our derivatives are accounted for as mark-to-market activities. For the three months ended June 30, 2014, the non-cash mark-to-market loss was approximately $5.9 million, compared to a non-cash mark-to-market gain of $2.3 million for the same period in 2013. The 2014 non-cash loss was the result of the impact of lower future expected oil and natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities, while non-performance risk was not a factor. The 2013 non-cash gain represented approximately $2.4 million from the impact of lower future expected oil and natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities, offset by a $0.1 million loss 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 June 30, 2014, lease operating expenses increased $1.3 million, or 32.7%, to $5.2 million, compared to expenses of $3.9 million for the same period in 2013. This increase in lease operating expenses was primarily related to $0.4 million in higher expenses due to the SEP I acquisition, along with an increase of $0.6 million in non-operated lease operating expenses, $0.3 million in higher parts and supplies and oil and gas treating costs, $0.2 million in higher insurance costs and $0.2 million in higher labor and benefits expenses.

For the three months ended June 30, 2014, per unit lease operating expenses were $2.25 per Mcfe compared to $2.11 per Mcfe for the same period in 2013.

For the three months ended June 30, 2014, production taxes increased $0.4 million, or 60.0%, to $1.0 million, compared to expenses of $0.6 million for the same period in 2013. This increase was primarily the result of higher market prices for natural gas and oil in 2014.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees and other costs not directly associated with field operations. General and administrative expenses increased $1.9 million, or 49.6%, to $5.6 million for the three months ended June 30, 2014, compared to $3.7 million for the same period in 2013. Our general and administrative expenses were higher in 2014 due to a management fee paid to SOG in conjunction with the Services Agreement of $1.0 million, $0.8 million in higher unit-based compensation and $0.1 million in higher legal and professional services costs.

Our per unit costs were $2.43 per Mcfe for the three months ended June 30, 2014, compared to $2.01 per Mcfe for the same period in 2013.

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 changes in the same direction.

Our depreciation, depletion and amortization expense for the three months ended June 30, 2014 was $4.3 million, or $1.88 per Mcfe, compared to $4.8 million, or $2.58 per Mcfe, for the same period in 2013. This decrease in depreciation, depletion and amortization reflects the increase in our reserve base at June 30, 2014. Our other assets are depreciated using the straight-line basis. Consistent with our prior practice, we are using our 2013 reserve report to calculate our depletion rate during the first three quarters of 2014 and will use our 2014 reserve report to record our depletion in the fourth quarter of 2014.

Interest expense. Interest expense for the three months ended June 30, 2014 decreased $0.3 million, or 38.3%, to $0.5 million, compared to $0.9 million for the same period in 2013. This decrease was due to a lower average debt outstanding balance, along with a lower average interest rate. The average interest rate on our outstanding debt was approximately 3.153% at June 30, 2014, compared to 3.192% during the same period in 2013.

Six months ended June 30, 2014 compared to six months ended June 30, 2013

Oil and natural gas sales. Unhedged oil and liquid sales increased $7.8 million, or 93.9%, to $16.2 million for the six months ended June 30, 2014, compared to $8.4 million for the same period in 2013. Unhedged natural gas sales increased $5.2 million, or 53.5%, to $14.8 million for the six months ended June 30, 2014, compared to $9.6 million for the same period in 2013. With hedges and mark-to-market activities, our total revenue increased $3.3 million when compared to the same period in 2013. Of this increase, $9.6 million was attributable to higher market prices for our natural gas and oil production and $3.4 million in higher volume variance, partially offset by $5.7 million attributable to lower cash hedge settlements from our hedge program and $4.0 million in lower mark-to-market activities. Production for the six months ended June 30, 2014 was 4.5 Bcfe, which was 0.7 Bcfe higher than the same period in 2013. We hedged all of our production volumes sold through June 30, 2014, and the same through June 30, 2013. Oil production increased approximately 106.5% during the six months ended June 30, 2014, compared to the six months ended June 30, 2013, as a result of our acquisition and development of properties located in Texas and Louisiana.

Cash hedge settlements received for our commodity derivatives were approximately $2.1 million for the six months ended June 30, 2014. Cash hedge settlements received for our commodity derivatives were approximately $7.8 million for the six months ended June 30, 2013. This difference was due to changes in hedge prices, hedged volumes and market prices for natural gas and oil during 2013 and 2014.

As discussed below, our non-cash mark-to-market activities decreased by $4.0 million for the six months ended June 30, 2014, compared to the same period in 2013. Our realized prices before our hedging program increased from 2013 to 2014 for our natural gas production; however, prices for our oil production decreased. This was offset by our hedging program and the mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. All of our derivatives are accounted for as mark-to-market activities. For the six months ended June 30, 2014, the non-cash mark-to-market loss was approximately $10.9 million, compared to a non-cash mark-to-market loss of $6.9 million for the same period in 2013. The 2014 non-cash loss was the result of the impact of lower future expected oil and natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities, while non-performance risk was not a factor. The 2013 non-cash loss represented approximately $6.8 million from the impact of higher future expected oil and natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities and a $0.1 million loss 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 six months ended June 30, 2014, lease operating expenses increased $2.1 million, or 26.5%, to $10.3 million, compared to expenses of $8.2 million for the same period in 2013. This increase in lease operating expenses was primarily related to $1.1 million in higher expenses due to the SEP I acquisition, along with an increase of $1.1 million in non-operated lease operating expenses, $0.4 million in higher parts and supplies and oil and gas treating costs, $0.3 million in higher insurance costs and $0.3 million in higher labor and benefits expenses.

For the six months ended June 30, 2014, per unit lease operating expenses were $2.27 per Mcfe compared to $2.11 per Mcfe for the same period in 2013.

For the six months ended June 30, 2014, production taxes increased $0.7 million, or 59.3%, to $1.8 million, compared to expenses of $1.1 million for the same period in 2013. This increase was primarily the result of increased oil production and higher market prices for natural gas in 2014.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees and other costs not directly associated with field operations. General and administrative expenses increased $1.0 million, or 12.5%, to $9.1 million for the six months ended June 30, 2014, compared to $8.1 million for the same period in 2013. Our general and administrative expenses were higher in 2014 due to a management fee paid to SOG in conjunction with the Services Agreement of $1.0 million, $0.5 million in higher legal and professional services costs and $0.5 million in higher unit-based compensation, partially offset by $0.8 million in lower severance costs and $0.2 million in lower labor and incentive compensation costs.

Our per unit costs were $2.02 per Mcfe for the six months ended June 30, 2014, compared to $2.11 per Mcfe for the same period in 2013.

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 changes in the same direction.

Our depreciation, depletion and amortization expense for the six months ended June 30, 2014 was $8.4 million, or $1.85 per Mcfe, compared to $9.6 million, or $2.48 per Mcfe, for the same period in 2013. This decrease in depreciation, depletion and amortization reflected the increase in our reserve base at June 30, 2014. Our other assets are depreciated using the straight-line basis. Consistent with our prior practice, we are using our 2013 reserve report to calculate our depletion rate during the first three quarters of 2014 and will use our 2014 reserve report to record our depletion in the fourth quarter of 2014.

For the six months ended June 30, 2014, our non-cash impairment charges were approximately $0.2 million to impair the value of our oil and natural gas fields in Texas and Louisiana. For the six months ended June 30, 2013, we did not have an impairment to record.

Interest expense. Interest expense for the six months ended June 30, 2014 decreased $1.1 million, or 52.3%, to $1.1 million, compared to $2.2 million for the same period in 2013. This decrease was due to a lower average debt outstanding balance during the first six months of 2014 compared to the first six months of 2013, along with a lower average interest rate. The average interest rate on our outstanding debt was approximately 3.153% at June 30, 2014 compared to 3.192% during the same period in 2013.

Liquidity and Capital Resources

During the first six months of 2014, 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 development of existing oil opportunities within our existing asset base in the Mid-Continent and Gulf Coast regions.

Based upon our current business plan for 2014, we anticipate that we will continue to generate sufficient operating cash flow to meet our working capital needs and fund a planned capital expenditure program between $20.0 million and $22.0 million. We will be monitoring the capital resources available to us to meet our future financial obligations and our planned 2014 capital expenditures. Our current expectation is that we will continue managing our business to operate within the cash flows that are generated. Our quarterly distributions to our unitholders remained suspended through the second quarter of 2014. 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.

Our future success in growing reserves and production will be highly dependent on the capital resources available to us and our success in drilling for or acquiring additional reserves and managing the costs associated with our operations. We routinely monitor and adjust our capital expenditures and operating expenses in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility and internally generated cash flow. Based upon current oil and natural gas price expectations, our existing hedge position and expected production levels in 2014, 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 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

As of June 30, 2014, the borrowing base under our reserve-based credit facility was $70.0 million and we had $52.0 million of debt outstanding under the facility, leaving us with $18.0 million in unused borrowing capacity. Our reserve-based credit facility matures on May 30, 2017.

Cash Flow from Operations

Our net cash flow provided by operating activities for the six months ended June 30, 2014 was $6.0 million, compared to $6.0 million for the same period in 2013.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of market prices for oil and natural gas, our hedging program and our level of production of oil and natural gas. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program, acquisitions and successful execution of 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. 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. All of our derivatives are with Societe Generale, a lender in our reserve-based credit facility, 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. 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.

Investing Activities—Acquisitions and Capital Expenditures

Cash used by investing activities was $5.0 million for the six months ended June 30, 2014, compared to cash provided by investing activities of $52.6 million for the same period in 2013. Our cash capital expenditures were $5.2 million, consisting of $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $2.3 million in development expenditures focused on oil completions in the Cherokee Basin and $1.5 million in development expenditures focused on properties in Texas and Louisiana. We completed four net wells and four net recompletions during the six months ended June 30, 2014 and had one net well and net recompletion in progress at June 30, 2014.

Our cash capital expenditures were $6.4 million for the six months ended June 30, 2013, which consisted of $6.3 million in development expenditures in the Cherokee Basin and $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin. We completed 26 net wells and 13 net recompletions during the first six months of 2013 and had five net wells and net recompletions in progress at June 30, 2013. We also sold our Robinson's Bend Field assets in the Black Warrior Basin of Alabama for net proceeds, after customary costs and working capital adjustments, of approximately $58.9 million.

Financing Activities

Net cash used in financing activities was $1.5 million for the six months ended June 30, 2014, compared to $51.0 million used by financing activities for the same period in 2013. During the six months ended June 30, 2014, we had borrowings under our reserve-based credit facility of $5.8 million for working capital purposes and repayments of $4.5 million. We used $1.65 million to purchase the Class C and Class D interests from CEPH, as part of the Exelon Litigation settlement. We used $0.8 million for the payment of the PostRock Litigation settlement of $6.5 million, which had been accrued at December 30, 2013, but was not paid until the second quarter of 2014. We used $0.2 million during the six months ended June 30, 2014 to fund the cost of units tendered by employees for tax withholdings for unit-based compensation.

Our net cash used by financing activities was $51.0 million for the six months ended June 30, 2013. We borrowed $0.2 million in short-term borrowings under our reserve-based credit facility for working capital purposes. During the first six months of 2013, we used $50.2 million to reduce our outstanding debt. This debt reduction was funded by 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.

Off-Balance Sheet Arrangements

As of June 30, 2014, we had no off-balance sheet arrangements with third parties, and we maintained no debt obligations that contained 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 June 30, 2014, we have not suffered any significant losses with our counterparties as a result of non-performance.

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 guarantees from Macquarie Bank Limited for up to $2.0 million in purchases through December 31, 2015, and up to $2.0 million in purchases through January 31, 2016. As of June 30, 2014, we had no past due receivables from Macquarie.

Scissortail Energy, LLC

Scissortail Energy, LLC (Scissortail), a subsidiary of Kinder Morgan Energy Partners, L.P., purchases a portion of our natural gas production in Oklahoma and Kansas. As of June 30, 2014, 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 June 30, 2014. As of June 30, 2014, we have no past due receivables from ONEOK.

Derivative Counterparties

As of June 30, 2014, all of our derivatives are with Societe Generale, a lender in our reserve-based credit facility, 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 June 30, 2014, each of these financial institutions had an investment grade credit rating.

Reserve-Based Credit Facility

As of June 30, 2014, 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 June 30, 2014, each of these financial institutions has an investment grade credit rating.

Outlook

During 2014, 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, 2013, 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 2014 Expected Results

Our 2014 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 that could lead to enhanced unitholder value. 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 2014, we currently anticipate:

•Our production to be in a range of 8.1 Bcfe to 9.3 Bcfe, approximately 93% of which is currently hedged.

•Our operating expenses to be actively managed, resulting in a range of $33.3 million to $37.3 million.

•Our Adjusted EBITDA to be in a range of $26.7 million to $29.9 million.

•Our total capital expenditures to be between $20.0 million to $22.0 million. Our entire capital budget for 2014 will be focused on capital efficient oil drilling and recompletion opportunities in our existing properties.

•At the present time, we are actively pursuing merger and acquisition opportunities that could lead to enhanced unitholder value.

Critical Accounting Policies and Estimates

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

As of June 30, 2014, 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, 2013, which was filed with the SEC on March 27, 2014. 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

This section is not applicable to smaller reporting companies.

Item 4. Controls and Procedures

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

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

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and the Chief Financial Officer of CEP have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of June 30, 2014 (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 natural gas computer software Schlumberger used. Additional experienced staffing has been hired, primarily in the revenue accounting and accounts payable functions.

During the six months ended June 30, 2014, 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 (the PostRock Litigation) in connection with the Company's closing on August 9, 2013 of the purchase of oil and natural gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contended, 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 bad faith conduct of the other defendants and interfered with CEPM's contractual rights under the Company's operating agreement. The plaintiffs alleged 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 alleged aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs sought, 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 had sole voting power with respect to the outstanding Class A units, declaratory relief that the Company's officers and managers breached fiduciary and contractual duties and were not entitled to indemnification from the Company as a result thereof, and monetary damages. On March 31, 2014, the parties to the lawsuit reached a settlement agreement and the lawsuit was subsequently dismissed. As a result of the settlement, the Class A units acquired by SEP I in the August 2013 transaction were returned to CEP and cancelled in exchange for $0.8 million; CEPM transferred 100% of its Class A units and 414,938 of CEP's Class B units to SEP I in exchange for an aggregate payment of $1.0 million from SEP I, and CEP paid $6.5 million to CEPM. In addition, pursuant to the terms of the settlement, CEPM agreed to sell its remaining Class B units over the next nine months, with SEP I providing up to a $5.0 million backstop payment to CEPM to the extent proceeds received by CEPM from such sale do not meet or exceed a specified amount. As a result of the settlement, the settling parties filed a stipulation in the Court of Chancery of the State of Delaware seeking to lift the preliminary injunction issued on December 3, 2013, and the litigation was dismissed with prejudice. The settlement also included mutual releases between the plaintiffs and defendants. In connection with the settlement, we received $1.25 million on April 10, 2014, under our directors and officers insurance policy.

On February 28, 2014, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPH against the Company (the Exelon Litigation) seeking repayment of suspended distributions in relation to the Class D Interests held by CEPH. In 2006, Constellation Holding, Inc (CHI), which merged with and into CEPH in December 2012, purchased the Company's Class D Interests for $8.0 million. The $8.0 million was to be repaid to CEPH in quarterly distributions of $333,333.33 over a period of six years; however, these distributions could be temporarily suspended if a dispute arose over pricing formulas related to the sale of natural gas from the Robinson's Bend properties. A dispute arose, so the distributions were suspended pursuant to the Company's operating agreement and never reinstated. CEPH contended, among other things, that the Company breached its contract to pay the quarterly distributions, acted in bad faith and received unjust enrichment by suspending the quarterly distributions. On June 26, 2014, the parties to the lawsuit reached a settlement agreement and the lawsuit was subsequently dismissed. In conjunction with the settlement, we paid CEPH $1.65 million in exchange for all of the Class C management incentive interests and the Class D interests held by CEPH, which accounted for all of such interests issued by CEP. Effective with the acquisition from CEPH, we cancelled the Class C management incentive interests and Class D interests.

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, 2013 that was filed with the SEC on March 27, 2014. 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 2013 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.

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. These statements may include discussions about our:

- business strategy;
- acquisition strategy;
- financial strategy;
- ability to resume, maintain and grow distributions;
- drilling locations;
- oil, natural gas and natural gas liquids reserves;
- realized oil, natural gas and natural gas liquids prices;
- production volumes;
- lease operating expenses, general and administrative expenses and developmental costs;
- future operating results and
- plans, objectives, expectations, forecasts, outlook and intentions.

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," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

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

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

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

1.Financial Statements:

Condensed Consolidated Balance Sheets – Constellation Energy Partners LLC at June 30, 2014 and December 31, 2013

Condensed Consolidated Statements of Operations and Comprehensive Income/(Loss) – Constellation Energy Partners LLC for the six months ended June 30, 2014 and June 30, 2013

Condensed Consolidated Statements of Cash Flows – Constellation Energy Partners LLC for the six months ended June 30, 2014 and June 30, 2013

Condensed Consolidated Statements of Changes in Members' Equity – Constellation Energy Partners LLC for the six months ended June 30, 2014

Notes to Condensed Consolidated Financial Statements

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: August 14, 2014	By	/s/ Charles C. Ward Charles C. Ward Chief Financial Officer and Treasurer