Constellation Energy Partners LLC
Form 10-Q
August 10, 2009
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2009

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 organization)	**(I.R.S. Employer Identification No.)**

100 Constellation Way

Baltimore, Maryland	**21202**
(Address of Principal Executive Offices)	**(Zip Code)**

Telephone Number: (410) 468-3500

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files.). Yes ¨ 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	x
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 x

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

Common Units outstanding on August 10, 2009: 22,105,826 units.

Table of Contents

TABLE OF CONTENTS

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income (Loss)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In 000 s except unit data)			
Revenues				
Oil and gas sales	$ 30,698	$ 38,994	$ 63,560	$ 70,419
Gain / (Loss) from mark-to-market activities (see Note 5)	(12,134)	(15,033)	7,197	(17,989)
Total revenues	18,564	23,961	70,757	52,430
Expenses:				
Operating expenses:				
Lease operating expenses	8,289	9,209	17,074	18,273
Cost of sales	612	2,239	1,444	3,387
Production taxes	560	2,885	1,530	4,550
General and administrative	4,311	3,787	9,647	7,122
(Gain) / Loss on sale of asset	(3)		14	(211)
Depreciation, depletion, and amortization	18,195	11,489	32,629	21,022
Accretion expense	56	101	157	202
Total operating expenses	32,020	29,710	62,495	54,345
Other expenses (income)				
Interest expense	3,278	3,102	6,121	5,662
Interest (income)		(43)	(2)	(284)
Other expense (income)	10	(18)	(47)	(4)
Total other expenses	3,288	3,041	6,072	5,374
Total expenses	35,308	32,751	68,567	59,719
Net income (Loss)	$ (16,744)	$ (8,790)	$ 2,190	$ (7,289)
Other comprehensive (Loss)	(11,354)	(94,813)	(3,641)	(143,062)
Comprehensive (Loss)	$ (28,098)	$ (103,603)	$ (1,451)	$ (150,351)
Earnings per unit (see Note 1)				
Earnings per unit Basic	$ (0.74)	$ (0.39)	$ 0.10	$ (0.33)
Units outstanding Basic	22,500,701	22,362,357	22,443,699	22,358,729
Earnings per unit Diluted	$ (0.74)	$ (0.39)	$ 0.10	$ (0.33)
Units outstanding Diluted	22,500,701	22,362,357	22,443,699	22,358,729
Distributions declared and paid per unit	$ 0. 13	$ 0.5625	$ 0.26	$ 1.1250

See accompanying notes to consolidated financial statements.

Table of Contents

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

(Unaudited)

	June 30, 2009	December 31, 2008
	(In 000 s)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 16,844	$ 6,255
Accounts receivable	6,031	9,363
Prepaid expenses	1,210	1,026
Risk management assets (see Note 5)	38,808	35,587
Total current assets	62,893	52,231
Oil and natural gas properties (See Note 7)		
Natural gas properties, equipment and facilities	790,099	769,103
Material and supplies	5,225	4,587
Less accumulated depreciation, depletion and amortization	(143,249)	(111,171)
Net oil and natural gas properties	652,075	662,519
Other assets		
Debt issue costs (net of accumulated amortization of $2,038 at June 30, 2009 and $1,495 at December 31, 2008)	1,513	1,963
Risk management assets (see Note 5)	28,625	29,746
Other non-current assets	11,732	12,390
Total assets	$ 756,838	$ 758,849
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 1,732	$ 2,809
Payable to affiliate	431	1,043
Accrued liabilities	10,921	10,088
Environmental liabilities	310	441
Royalty payable	3,479	5,125
Total current liabilities	16,873	19,506
Other liabilities		
Asset retirement obligation	6,999	6,754
Debt	220,000	212,500
Total other liabilities	226,999	219,254
Total liabilities	243,872	238,760
Commitments and contingencies (See Note 9)		
Class D Interests	6,667	6,667
Members equity		

Class A units, 451,142 and 447,721 shares authorized, issued and outstanding, respectively	9,196	9,266
Class B units, 22,648,763 and 22,348,763 shares authorized, respectively, and 22,105,826 and 21,938,342 issued and outstanding, respectively	450,617	454,029
Accumulated other comprehensive income	46,486	50,127
Total members equity	506,299	513,422
Total liabilities and members equity	$ 756,838	$ 758,849

See accompanying notes to consolidated financial statements.

4

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Six months ended June 30, 2009	Six months ended June 30, 2008
	(In 000 s)	
Cash flows from operating activities:		
Net income (Loss)	$ 2,190	$ (7,289)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	32,629	21,022
Amortization of debt issuance costs	543	511
Accretion of plugging and abandonment liability	157	202
Equity earnings (losses) in affiliate	(47)	(4)
(Gain) Loss from disposition of property and equipment	14	(211)
Hedge ineffectiveness	267	804
(Gain) Loss from mark-to-market activities on commodity and interest rate derivatives	(6,298)	17,989
Unit-based compensation programs	152	155
Changes in Assets and Liabilities:		
Change in net risk management assets and liabilities	290	(683)
(Increase) decrease in accounts receivable	3,332	(6,455)
(Increase) decrease in prepaid expenses	(184)	579
(Increase) decrease in other assets	2	401
Increase (decrease) in accounts payable	(1,077)	1,082
Increase (decrease) in payable to affiliate	(612)	(1,854)
Increase (decrease) in accrued liabilities	(105)	2,322
Increase (decrease) in royalty payable	(1,646)	3,686
Net cash provided by operating activities	29,607	32,257
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash required	29	(50,379)
Development of natural gas properties	(20,806)	(19,396)
Proceeds from sale of equipment	17	472
Distributions from equity affiliate	160	223
Net cash used in investing activities	(20,600)	(69,080)
Cash flows from financing activities:		
Members distributions	(5,820)	(25,485)
Proceeds from issuance of debt	34,500	220,000
Repayment of debt	(27,000)	(157,000)
Costs for shelf registration statement	(4)	(340)
Debt issue costs	(94)	(1,427)
Net cash provided by financing activities	1,582	35,748
Net (decrease) increase in cash	10,589	(1,075)
Cash and cash equivalents, beginning of period	6,255	18,689

Cash and cash equivalents, end of period	$ 16,844	$ 17,614
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 825	$ 311
Cash received during the period for interest	$ 2	$ 322
Cash paid during the period for interest	$ (3,915)	$ (5,049)

See accompanying notes to consolidated financial statements.

Table of Contents

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members Equity

(Unaudited)

	Class A		Class B		Accumulated Other Comprehensive Income (Loss)	Total Members Equity
	Units	Amount	Units	Amount		
	(In 000 s, except unit amounts)					
Balance, December 31, 2008	447,721	$ 9,266	21,938,342	$ 454,029	$ 50,127	$ 513,422
Distributions		(116)		(5,704)		(5,820)
Equity Issuance Cost				(4)		(4)
Change in fair value of commodity hedges					20,290	20,290
Cash settlement of commodity hedges					(25,771)	(25,771)
Cash settlement of interest rate hedges					1,840	1,840
Unit-based compensation programs	3,421	3	167,484	149		152
Net income		43		2,147		2,190
Balance, June 30, 2009	451,142	$ 9,196	22,105,826	$ 450,617	$ 46,486	$ 506,299

See accompanying notes to consolidated financial statements.

6

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

The consolidated financial statements as of, and for the period ended June 30, 2009, are unaudited, but in the opinion of management include all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (GAAP) have been condensed or omitted under Securities and Exchange Commission (SEC) rules and regulations. The results reported in these unaudited consolidated financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

The financial information included herein should be read in conjunction with the financial statements and notes in the Company s Annual Report on Form 10-K for the year ended December 31, 2008. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2009 financial statement presentation.

CBM Equity IV Holdings, LLC was organized as a limited liability company on February 7, 2005, under the laws of the State of Delaware and had no principal operations prior to the acquisition of our properties in the Black Warrior Basin on June 13, 2005. On May 10, 2006, CBM Equity IV Holdings, LLC changed its name to Constellation Energy Resources LLC. On July 18, 2006, Constellation Energy Resources LLC changed its name to Constellation Energy Partners LLC (CEP or the Company). CEP completed its initial public offering on November 20, 2006, and is traded on the NYSE Arca under the symbol CEP . CEP is partially-owned by Constellation Energy Commodities Group, Inc. (CCG), which is owned by Constellation Energy Group, Inc. (NYSE: CEG) (Constellation or CEG). As of June 30, 2009, affiliates of Constellation own all of the Company s Class A units, all of the management incentive interests, approximately 27% of the Company s common units and all of the Company s Class D interests.

The Company is currently focused on the development and acquisition of natural gas properties in the Black Warrior Basin in Alabama, the Cherokee Basin in Kansas and Oklahoma, and the Woodford Shale in Oklahoma (collectively the Oil and Gas Properties). CEP acquired its interests in the Black Warrior Basin in 2005, its interests in the Cherokee Basin in 2007 and its interests in the Woodford Shale in 2008.

Accounting policies used by CEP conform to accounting principles generally accepted in the United States of America. The accompanying financial statements include the accounts of CEP and its wholly-owned subsidiaries (collectively, the Entities). All significant intercompany accounts and transactions have been eliminated in consolidation. CEP operates its oil and natural gas properties as one business segment, the exploration, development and production of natural gas. Management of CEP evaluates performance based on one business segment as there are not different economic environments within the operation of the oil and natural gas properties. Certain reclassifications have been made to prior years reported amounts in order to conform with the current year presentation. These reclassifications did not impact net income, members equity or cash flows.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Company s significant accounting policies are consistent with those discussed in its Annual Report on Form 10-K for the year ended December 31, 2008.

Earnings per Unit

Basic earnings per unit (EPS) are computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. At June 30, 2009, we had 451,142 Class A units and 22,105,826 Class B units outstanding. Of the Class B units, 190,716 units are unvested restricted common units granted and outstanding.

Table of Contents

The following table presents earnings per common unit amounts computed using SFAS 128:

	Income	Units	Per Unit Amount
	(In 000	s except unit data)	
For the three months ended June 30, 2009			
Basic EPS:			
Income allocable to unitholders	$ (16,744)	22,500,701	$ (0.74)
Effect of dilutive securities:			
Notional common units that earn distributions			
Diluted EPS:			
Income allocable to common unitholders	$ (16,744)	22,500,701	$ (0.74)

	Income	Units	Per Unit Amount
	(In 000	s except unit data)	
For the six months ended June 30, 2009			
Basic EPS:			
Income allocable to unitholders	$ 2,190	22,443,699	$ 0.10
Effect of dilutive securities:			
Notional common units that earn distributions(a)			
Diluted EPS:			
Income allocable to common unitholders	$ 2,190	22,443,699	$ 0.10

(a) We have also issued 1,003,573 notional units that earn distributions under certain circumstances. These notional units will convert into restricted common units upon approval by our unitholders. Had these units be included in our diluted EPS calculations for the six months ended June 30, 2009, our total diluted units would be 23,447,272 and our EPS would have been $0.09 per unit.

	Income	Units	Per Unit Amount
	(In 000	s except unit data)	
For the three months ended June 30, 2008			
Basic EPS:			
Income allocable to unitholders	$ (8,790)	22,362,357	$ (0.39)
Effect of dilutive securities:			
Restricted common units Treasury stock method			
Diluted EPS:			
Income allocable to common unitholders	$ (8,790)	22,362,357	$ (0.39)

	Income	Units	Per Unit Amount
	(In 000	s except unit data)	
For the six months ended June 30, 2008			
Basic EPS:			
Income allocable to unitholders	$ (7,289)	22,358,729	$ (0.33)
Effect of dilutive securities:			
Restricted common units Treasury stock method			
Diluted EPS:			
Income allocable to common unitholders	$ (7,289)	22,358,729	$ (0.33)

3. NEW ACCOUNTING PRONOUNCEMENTS

In May 2009, the Financial Accounting Standards Board issued SFAS 165, *Subsequent Event* (SFAS 165). SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist in the auditing standards. The standard, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. CEP performs an evaluation of subsequent events until the issuance date of its document with the SEC so the adoption of SFAS 165 had no impact on our financial statements. See Note 16 for additional information.

In June 2008, the Financial Accounting Standards Board issued a FASB Staff Position (FSP) on EITF Issue No. 03-06-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. This FSP addresses whether instruments granted in unit-based payment transactions are participating securities prior to vesting and,

Table of Contents

therefore, need to be included in the earnings allocation in computing earnings per unit under the two-class method described in SFAS 128, *Earnings Per Share*. It affects entities that accrue or pay nonforfeitable cash distributions on unit-based payment awards during the awards service period. FSP EITF 03-06-1 is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years and will require a retrospective adjustment to all prior period earnings per unit calculations. CEP adopted FSP EITF 03-06-1 on January 1, 2009, and began including all unvested LTIP restricted common units that earn distributions in earnings per unit calculations for all periods presented.

In March 2008, the Emerging Issues Task Force reached a consensus on Issue 07-4, or EITF 07-4, Application of the Two-Class Method under FASB Statement 128, *Earnings Per Share*, to Master Limited Partnerships. EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. This Issue is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted, and the guidance in this Issue is to be applied retrospectively for all financial statements presented. The adoption of this Issue did not have a material impact on our financial statements.

In March 2008, the FASB issued SFAS 161, *Disclosures About Derivative Instruments and Hedging Activities*. SFAS 161 is effective beginning January 1, 2009 and requires entities to provide expanded disclosures about derivative instruments and hedging activities including (1) the ways in which an entity uses derivatives, (2) the accounting for derivatives and hedging activities, and (3) the impact that derivatives have (or could have) on an entity s financial position, financial performance, and cash flows. SFAS 161 requires expanded disclosures and does not change the accounting for derivatives. The adoption of this standard did not have a material impact on our financial statements. See Note 5 for additional information.

New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2009, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us.

In June 2009, the Financial Accounting Standards Board released the final version of its new Accounting Standards Codification (the Codification) as the single authoritative source for U.S. GAAP. The Codification replaces all previous U.S. GAAP accounting standards as described in SFAS 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* (SFAS 168). While not intended to change U.S. GAAP, the Codification significantly changes the way in which the accounting literature is organized. It is structured by accounting topic to help accountants and auditors more quickly identify the guidance that applies to a specific accounting issue. However, because the Codification completely replaces existing standards, it will affect the way U.S. GAAP is referenced by companies in their financial statements and accounting policies. The Codification is effective for financial statements that cover interim and annual periods ending after September 15, 2009. We are currently evaluating the potential impact of adopting the Codification.

In December 2008, the Securities and Exchange Commission (SEC) issued the final rule, Modernization of Oil and Gas Reporting (Final Rule). The Final Rule adopts revisions to the SEC s oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and technological advances. Revised requirements in the Final Rule include, but are not limited to:

- Oil and gas reserves must be reported using a 12-month average of the closing prices on the first day of each of such months, rather than a single day year-end price;
- Companies will be allowed to report, on a voluntary basis, probable and possible reserves, previously prohibited by SEC rules; and
- Easing the standard for the inclusion of proved undeveloped reserves (PUDs) and requiring disclosure of information indicating any progress toward the development of PUDs.

We are currently evaluating the potential impact of adopting the Final Rule. The SEC is discussing the Final Rule with the FASB and IASB staffs to align accounting standards with the Final Rule. These discussions may delay the required compliance date. Absent any change in such date, we will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ended December 31, 2009. Voluntary early compliance is not permitted.

Table of Contents

4. ACQUISITIONS

CoLa Acquisition

On March 31, 2008, the Company acquired 83 non-operated producing natural gas wells in the Woodford Shale in the Arkoma Basin in Oklahoma from CoLa Resources LLC (CoLa) for $50.2 million, including purchase price adjustments (CoLa Acquisition). CoLa is an affiliate of CEG, the Company s sponsor. The transaction was reviewed and approved by the Company s conflicts committee. In its review, the Company s conflicts committee considered various economic factors (including historical and estimated future production, estimated proved reserves, future pricing estimates and operating cost estimates) regarding the transaction, and determined that the acquisition was fair and in the best interests of the Company. The 83 wells, located in Coal and Hughes Counties, Oklahoma, have an average gross working interest per well of 11.4% and an average net revenue interest per well of 9.2%. The acquired natural gas reserves associated with the wells are 100% proved developed producing. Our results of operations include the results of the CoLa wells after the date of acquisition.

To fund the purchase of CoLa, the Company borrowed $53.0 million under its reserve-based credit facilities (see Note 6).

Upon the announcement of the acquisition, the Company entered into derivative transactions to hedge a portion of the future expected production associated with these wells (see Note 5).

The total consideration paid was $50.2 million, which consisted of $50.3 million in cash and transaction costs and assumed liabilities of approximately $0.1 million, primarily associated with asset retirement obligations on the properties. The following table summarizes the allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition.

Acquired March 31, 2008	**(in millions)**
Oil and Natural Gas Properties	$ 50.3
Total assets acquired	50.3
Asset retirement obligations	(0.1)
Net assets acquired	$ 50.2

The purchase price allocation is based on evaluations of estimated proved oil and natural gas reserves, discounted cash flows, quoted market prices, and other estimates by management.

The purchase price allocation related to the CoLa Acquisition remains subject to post-closing or title adjustments. Under the purchase agreement, the Company will have the right to assert, and CoLa will have the right to attempt to cure, any title defects to the acquired wells until July 31, 2009. CoLa s post-closing payment obligations with respect to title defects and indemnities under the purchase agreement is secured, in part, by a guaranty from CCG delivered at closing. The maximum amount of the CCG guaranty is limited to (i) 20% of the purchase price, with respect to indemnity obligations, and (ii) with respect to title defect obligations, the amount of such title defects, such amount to be calculated as provided in the purchase agreement. The amount of CCG s guaranty with respect to title defect obligations will decrease as title curative is received or CoLa receives proceeds of production from the wells as to which payments of production proceeds had not commenced as of the closing date and which are attributable to periods prior to the effective time of the purchase agreement. Under certain circumstances, identified title defects may result in a purchase price adjustment. See Note 16 for additional information.

Pro Forma Results

The unaudited pro forma results presented below have been prepared to give effect to the CoLa Acquisition described above on our results of operations as if it had been consummated at the beginning of the period presented. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or to project our results of operations for any future date or period.

Table of Contents

	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008
	(Unaudited) (In 000 s, except per share data)	
Pro forma financial results:		
Revenue	$ 23,961	$ 55,763
Income (loss) from operations	(5,749)	(1,152)
Net income (loss)	(8,790)	(7,289)
Basic earnings (loss) per share	$ (0.39)	$ (0.33)
Diluted earnings (loss) per share	$ (0.39)	$ (0.33)

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

Mark-to-Market Activities

The Company has hedged a portion of its expected natural gas sales from currently producing wells through December 2013. All of the Company s swaps, basis swaps and options are accounted for as mark-to-market activities as of June 30, 2009.

At June 30, 2009, and December 31 2008, the Company had debt outstanding of $220.0 million and $212.5 million, respectively, under its reserve-based credit facilities. The Company has entered into hedging arrangements in the form of interest rate swaps to reduce the impact of volatility stemming from changes in the London interbank offered rate (LIBOR) on $168.0 million of the outstanding debt through October 2010. All of the Company s interest rate swaps are accounted for as mark-to-market activities as of June 30, 2009.

For the six months ended June 30, 2009 and 2008, the Company recognized mark-to-market gains of approximately $7.2 million and losses of approximately $18.0 million, respectively, in connection with its commodity derivatives. For the six months ended June 30, 2009 and 2008, the Company recognized mark-to-market losses of approximately $0.9 million and no gains or losses, respectively, in connection with its interest rate derivatives. At June 30, 2009 and December 31, 2008, the fair value of the derivatives accounted for as mark-to-market activities amounted to a net asset of approximately $67.4 million and a net asset of approximately $20.9 million, respectively.

Accumulated Other Comprehensive Income

Prior to the first quarter of 2009, the Company accounted for certain of its commodity and interest rate derivatives as hedging activities under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. The value of the cash flow hedges included in Accumulated other comprehensive income (loss) on the Consolidated Balance Sheets was an unrecognized gain of approximately $46.5 million and an unrecognized gain of $50.1 million at June 30, 2009 and December 31, 2008, respectively. The Company expects that the unrecognized gain will be reclassified from Accumulated other comprehensive income (loss) to the income statement in the following periods:

For the Quarter Ended	Commodity Derivatives	Interest Rate Derivatives	Non-performance Risk	Total AOCI
		(In 000 s)		
September 30, 2009	11,038	(1,272)	(67)	9,699
December 31, 2009	9,921	(1,222)	(93)	8,606
March 31, 2010	5,728	(1,149)	(52)	4,527
June 30, 2010	4,319	(964)	(51)	3,304
September 30, 2010	3,726	(892)	(54)	2,780
December 31, 2010	3,568	(326)	(62)	3,180
March 31, 2011	1,154		(33)	1,121
June 30, 2011	2,791		(93)	2,698
September 30, 2011	2,494		(93)	2,401
December 31, 2011	1,874		(77)	1,797
March 31, 2012	845		(26)	819
June 30, 2012	2,257		(77)	2,180

11

Table of Contents

For the Quarter Ended	Commodity Derivatives	Interest Rate Derivatives (In 000 s)	Non-performance Risk	Total AOCI
September 30, 2012	2,016		(74)	1,942
December 31, 2012	1,491		(59)	1,432
Total	$ 53,222	$ (5,825)	$ (911)	$ 46,486

Fair Value Measurements

We use SFAS 157, *Fair Value Measurements,* to measure fair value of our financial assets and liabilities on a recurring basis. Beginning January 1, 2009, we also applied SFAS 157 to non-financial assets and liabilities. SFAS 157 defines fair value, establishes a framework for measuring fair value and requires certain disclosures about fair value measurements for assets and liabilities measured on a recurring basis. All of CEP s derivative instruments are recorded at fair value in our financial statements. Fair value is the exit price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

SFAS 157 also establishes a hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

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

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

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

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Certain of our derivatives are classified as Level 3 because observable market data is not available for all of the time periods for which we have derivative instruments. As observable market data becomes available for all of the time periods, these derivative positions will be reclassified as Level 2. 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 or Level 3. We prioritize the use of the highest level inputs available in determining fair value.

The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Because of the long-term nature of certain assets and liabilities measured at fair value as well as differences in the availability of market prices and market liquidity over their terms, inputs for some assets and liabilities may fall into any one of the three levels in the fair value hierarchy. While SFAS 157 requires us to classify these assets and liabilities in the lowest level in the hierarchy for which inputs are significant to the fair value measurement, a portion of that measurement may be determined using inputs from a higher level in the hierarchy.

The following tables sets forth by level within the fair value hierarchy the Company s assets and liabilities that were measured at fair value on a recurring basis as of June 30, 2009, and December 31, 2008.

At June 30, 2009	Level 1	Level 2	Level 3 (In 000 s)	Netting and Cash Collateral*	Total Net Fair Value
Risk management assets	$	$ 67,699	$ (266)	$	$ 67,433
Risk management liabilities	$	$	$	$	$

Total	$	$ 67,699	$ (266)	$	$ 67,433

* *All of our derivative instruments are secured by our reserve-based credit facilities.*

Table of Contents

At December 31, 2008	Level 1	Level 2	Level 3	Netting and Cash Collateral*	Total Net Fair Value
			(In 000 s)		
Risk management assets	$	$ 58,581	$ 6,752	$	$ 65,333
Risk management liabilities	$	$	$	$	$
Total	$	$ 58,581	$ 6,752	$	$ 65,333

* *All of our derivative instruments are secured by our reserve-based credit facilities.*

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

The valuation of our derivatives is currently performed by Constellation under a management services agreement (see Note 8). In order to determine the fair value amounts presented above, Constellation utilizes various factors, including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and parental guarantees), but also the impact of our nonperformance risk on our liabilities. We currently use our reserve-based credit facilities to provide credit support for our derivative transactions. Historically, in connection with certain of our acquisitions, we have used guarantees from Constellation to provide credit support for our derivative transactions associated with the acquisition volumes. As a result, we do not post cash collateral with our counterparties, nor make any adjustments for non-performance credit risk on our liabilities with counterparties. We utilize observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating our assets from counterparties. At June 30, 2009, the impact of non-performance credit risk on the valuation of our assets from counterparties was $0.8 million, of which $0.1 million was reflected as an increase to our non-cash market-to-market gain and $0.9 million was reflected as a reduction to our accumulated other comprehensive income.

In certain instances, Constellation may utilize internal models to measure the fair value of our derivative instruments. Generally, Constellation uses similar models to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the assets or liabilities, and market-corroborated inputs, which are inputs derived principally from or corroborated by observable market data by correlation or other means.

The following table sets forth a reconciliation of changes in the fair value of risk management assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended June 30, 2009 (In 000 s)	*Six Months Ended June 30, 2009 (In 000 s)*
Balance at beginning of period	$ 4,973	$ 6,752
Realized and unrealized gains:		
Included in earnings	(6,889)	(6,936)
Included in other comprehensive income	0	(1,311)
Purchases, sales, issuances, and settlements	1,650	1,229
Transfers into and out of Level 3(a)	0	0
Balance as of June 30, 2009	$ (266)	$ (266)
Change in unrealized gains relating to derivatives still held as of June 30, 2009	$ (5,691)	$ (7,255)

(a) Reflects transfers of derivatives from Level 3 to Level 2 because observable market data is available for all time periods for which we have derivative instruments.

Table of Contents

	Three Months Ended June 30, 2008 (In 000 s)	Six Months Ended June 30, 2008 (In 000 s)
Balance at beginning of period	$ (9,246)	$ (3,591)
Realized and unrealized gains:		
Included in earnings	(9,403)	(8,935)
Included in other comprehensive income	(18,600)	(25,047)
Purchases, sales, issuances, and settlements	(1,177)	(853)
Transfers into and out of Level 3(a)	0	0
Balance as of June 30, 2008	$ (38,426)	$ (38,426)
Change in unrealized gains (losses) relating to derivatives still held as of June 30, 2008	$ (29,477)	$ (35,278)

(a) Reflects transfers of derivatives from Level 3 to Level 2 because observable market data is available for all time periods for which we have derivative instruments.

Credit Support Fee Agreements

In connection with certain of our acquisitions, Constellation entered into credit support agreements with us to provide guarantees to three banks that required credit support for certain financial derivatives. These guarantees were obtained because we did not own the assets at the time the derivatives were entered into and we could not use our existing reserve-based credit facility to provide collateral for the derivative transactions.

In February 2008, in connection with the CoLa Acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $8.5 million for certain financial derivatives that we entered into with BNP Paribas (BNP) and Societe Generale (SocGen). These guarantees have been released.

Through June 30, 2008, Constellation charged us $0.1 million for this credit support.

Fair Value of Financial Instruments

At June 30, 2009, the carrying values of cash and cash equivalents, accounts receivable, other current assets and current liabilities on the Consolidated Balance Sheets approximate fair value because of their short term nature. The Company believes the carrying value of long-term debt approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms, which represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties.

The following fair value disclosures are applicable under SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities*, as of June 30, 2009:

		Fair Value of Asset / (Liability) on Balance Sheet	
Derivative Type	Location of Asset / (Liability) on Balance Sheet	Six Months Ended June 30, 2009	Year Ended December 31, 2008
Commodity-MTM	Risk management assets	$ 86,699	$ 26,934
Commodity-MTM	Risk management assets	(12,540)	(5,987)
Interest Rate-MTM	Risk management assets	(6,726)	

	Total MTM Derivatives	$ 67,433	$ 20,947
Commodity-Cash Flow	Risk management assets	$	$ 52,232
Commodity-Cash Flow	Risk management assets		(182)
Interest Rate-Cash Flow	Risk management assets		(7,665)
	Total Cash Flow Derivatives	$	$ 44,385
	Total Derivatives	$ 67,433	$ 65,332

		Amount of Gain / (Loss) in Income	
Derivative Type	**Location of Gain / (Loss) in Income**	**Quarter Ended June 30, 2009**	**Quarter Ended June 30, 2008**
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ (12,134)	$ (15,032)
Commodity-MTM	Oil and gas sales	$ 4,795	$ 413
Interest Rate-MTM	Interest expense	(1,782)	(470)
	Total MTM Derivatives	$ (9,121)	$ (15,089)

Table of Contents

Derivative Type	Location of Gain / (Loss) in Income	Amount of Gain / (Loss) in Income Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ 7,197	$ (17,988)
Commodity-MTM	Oil and gas sales	$ 6,798	$ (657)
Interest Rate-MTM	Interest expense	(2,728)	(423)
	Total MTM Derivatives	$ 11,267	$ (19,068)

Derivative Type	Location of Gain / (Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain /(Loss) Reclassified from AOCI into Income - Effective: Quarter Ended June 30, 2009	Quarter Ended June 30, 2008	Amount of Gain /(Loss) in Income - Ineffective: Quarter Ended June 30, 2009	Quarter Ended June 30, 2008
Commodity-Cash Flow	Oil and gas sales	$ 12,623	$ (7,773)	$	$ (410)
Interest Rate-Cash Flow	Interest expense	(1,239)	(470)		
	Total Cash Flow	$ 11,384	$ (8,243)	$	$ (410)

Derivative Type	Location of Gain / (Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain /(Loss) Reclassified from AOCI into Income - Effective: Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Amount of Gain /(Loss) in Income - Ineffective: Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Commodity-Cash Flow	Oil and gas sales	$ 25,771	$ (5,879)	$ 267	$ 804
Interest Rate-Cash Flow	Interest expense	(1,840)	(423)		
	Total Cash Flow	$ 23,931	$ (6,302)	$ 267	$ 804

As of June 30, 2009, the Company has interest rate swaps on $168.0 million of its outstanding debt through October 2010, various commodity swaps for 39,215,000 MMbtu of natural gas production through December 2013, various basis swaps for 19,571,500 MMbtu of natural gas production in the Cherokee Basin through December 2012, and a put option for 160,000 MMbtu of natural gas production through December 2009. See Note 16 for additional information.

6. DEBT

Reserve-Based Credit Facility

On March 28, 2008, the Company entered into a new credit agreement and an amended and restated credit agreement, each as discussed below. The two agreements contain similar commercial terms with the same lenders participating in the same applicable percentages. A cross-default feature provides that an event of default under one agreement constitutes an event of default under the other. Each credit agreement is secured by distinct mortgages of properties as well as guarantees by the Company s subsidiaries.

The current lenders and their percentage commitments in each of the two credit facilities are: The Royal Bank of Scotland (23.32%), BNP Paribas (22.55%), Wachovia Bank, N.A. (14.55%), Bank of Nova Scotia (17.00%), Calyon (15.05%), and Societe Generale (7.53%).

New Credit Agreement

On March 28, 2008, the Company entered into a new $500.0 million secured credit agreement (Credit Facility) with The Royal Bank of Scotland plc as administrative agent (the Administrative Agent) and a syndicate of lenders. The amount available for borrowing at any one time is limited to the borrowing base for the Company s properties other than in the State of Alabama. As of June 30, 2009, the borrowing base under the $500.0 million Credit Facility was $115.0 million. The borrowing base is re-determined semi-annually by the lenders in their sole discretion based on reserve reports as prepared by reserve engineers, together with, among other things, the oil and natural gas prices at such time. Any increase in each borrowing base must be approved by all of the lenders. The Credit Facility matures on October 31, 2010.

Borrowings under the Credit Facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties located in states other than Alabama, payment of expenses incurred in connection with the credit facilities, working capital and general limited liability company purposes. The Credit Facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit.

At the Company s election, interest for borrowings under the Credit Facility is determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 1.25% and 2.00% per annum based on utilization or (ii) a domestic bank rate plus an applicable margin between 0.25% and 1.00% per annum based on utilization. Interest on borrowings under the Credit Facility is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The Credit Facility contains various covenants that limit, among other things, the Company s, and certain of the Company s subsidiaries , ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of the Company s assets, make certain loans, acquisitions, capital expenditures and investments, and make distributions other than from available cash.

In addition, the Company is required to maintain (i) a ratio of debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus 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 or sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.50 to 1.00; (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, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143, *Accounting for Asset Retirement Obligations* (including the current liabilities in respect of the termination of natural gas and interest rate swaps). All financial covenants are calculated using CEP s consolidated financial information.

The 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 Credit Facility and a change of control. If an event of default occurs under the Credit Facility, the lenders will be able to accelerate the maturity of the Credit Facility and exercise other rights and remedies.

The 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 the Company and its subsidiaries who are guarantors taken as a whole. If a MAE were to occur, CEP would be prohibited from borrowing under the reserve-based credit facilities and would be in default under the facilities, which could cause all of its existing indebtedness to become immediately due and payable.

Borrowings under the Credit Facility are secured by various mortgages of properties that the Company owns in states other than Alabama as well as a security and pledge agreement among the Company and certain of its subsidiaries and the Administrative Agent.

We have the ability to borrow under the Credit Facility to pay distributions to unitholders as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding under the credit facilities exceed 90% of the borrowing base. As of June 30, 2009, the Company is restricted from paying distributions to unitholders as the borrowings outstanding under its two credit facilities exceed 90% of the borrowing base.

Through June 30, 2009, the Company has borrowed $112.0 million under the Credit Facility.

Amended and Restated Credit Agreement

On March 28, 2008, the Company amended and restated its existing $200.0 million credit facility by entering into an amended and restated credit agreement with the Administrative Agent and a syndicate of lenders (the Amended and Restated Credit Facility). As of June 30, 2009, the borrowing base under the $200.0 million Amended and Restated Credit

16

Facility was $110.0 million. The amount available for borrowing at any one time is limited to the borrowing base for the Company s properties in the State of Alabama. The borrowing base is re-determined semi-annually by the lenders in their sole discretion based on reserve reports as prepared by reserve engineers, together with, among other things, the oil and natural gas prices at such time. Any increase in each borrowing base must be approved by all of the lenders. The Amended and Restated Credit Facility matures on October 31, 2010.

Borrowings under the Amended and Restated Credit Facility are available for acquisition, exploration and the operation and maintenance of oil and natural gas properties located in the State of Alabama, payment of expenses incurred in connection with the credit facilities, working capital and general limited liability company purposes. The Amended and Restated Credit Facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit.

At the Company s election, interest for borrowings under the Amended and Restated Credit Facility is determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 1.25% and 2.00% per annum based on utilization or (ii) a domestic bank rate plus an applicable margin between 0.25% and 1.00% per annum based on utilization. Interest on borrowings under the Amended and Restated Credit Facility is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The Amended and Restated Credit Facility contains various covenants that limit, among other things, the Company s, and certain of the Company s subsidiaries , ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of the Company s assets, make certain loans, acquisitions, capital expenditures and investments, and make distributions other than from available cash.

In addition, the Company is required to maintain (i) a ratio of debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus 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 or sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.50 to 1.00; (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 obligations under the credit facilities, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143, *Accounting for Asset Retirement Obligations* (including the current liabilities in respect of the termination of natural gas and interest rate swaps). All financial covenants are calculated using CEP s consolidated financial information.

The Amended and Restated 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 Amended and Restated Credit Facility and a change of control. If an event of default occurs under the Amended and Restated Credit Facility, the lenders will be able to accelerate the maturity of the Amended and Restated Credit Facility and exercise other rights and remedies.

The Amended and Restated 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 the Company and its subsidiaries who are guarantors taken as a whole. If a MAE were to occur, CEP would be prohibited from borrowing under the reserve-based credit facilities and would be in default under the facilities, which could cause all of its existing indebtedness to become immediately due and payable.

Borrowings under the Amended and Restated Credit Facility are secured by various mortgages of properties the Company owns in Alabama as well as a security and pledge agreement among the Company and certain of its subsidiaries and the Administrative Agent.

We have the ability to borrow under the Amended and Restated Credit Facility to pay distributions to unitholders as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding under the credit facilities exceed 90% of the borrowing base. As of June 30, 2009, the Company is restricted from paying distributions to unitholders as the borrowings outstanding under its two credit facilities exceed 90% of the borrowing base.

Through June 30, 2009, the Company has borrowed $108.0 million under the Amended and Restated Credit Facility.

Table of Contents

Debt Issue Costs

Total debt issue costs incurred through June 30, 2009, were approximately $3.5 million. These costs are being amortized over the life of the credit facilities.

Funds Available for Borrowing

As of June 30, 2009, the Company had $220.0 million in outstanding debt under its reserve-based credit facilities and $5.0 million in remaining borrowing capacity. As of June 30, 2008, the Company had $216.0 million in outstanding debt under its reserve-based credit facilities.

Compliance with Debt Covenants

Our reserve-based credit facilities mature in October 2010 and, as a result, amounts due under the facilities are scheduled to become a current liability in October 2009. To date, we have not entered into an agreement to refinance or extend the due date on the reserve-based credit facilities. We may not be able to renew or replace the facilities at similar borrowing costs, terms, covenants, restrictions, or borrowing base, or with similar debt issue costs. In addition, we do not believe that our forecasted cash flow will be sufficient to meet the principal payment that would be required on our outstanding debt balance as it comes due on October 31, 2010 unless we are able to successfully refinance our outstanding debt, extend the due date on our current credit facilities or sell assets. Our inability to refinance our outstanding debt would have a material adverse effect on the Company.

The reserve-based credit facilities limit the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. 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 prepared by reserve engineers, together with, among other things, the oil and natural gas prices existing at the time. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the reserve-based credit facilities. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the reserve-based credit facilities. Our current combined borrowing base under the reserve-based credit facilities is $225.0 million and we expect that the next borrowing base redetermination will occur within the next six months.

At June 30, 2009, CEP believes that it was in compliance with the debt covenants contained in its credit facilities. As of June 30, 2009, the actual debt to Adjusted EBITDA ratio was 3.1 to 1.0 as compared with a required ratio of not greater than 3.5 to 1.0, the actual ratio of current assets to current liabilities was 1.7 to 1.0 as compared with a required ratio of not less than 1.0 to 1.0, and the actual Adjusted EBITDA to cash interest expense ratio was 12.5 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If CEP is unable to remain in compliance with the debt covenants associated with its reserve-based credit facilities or maintain the required ratios discussed above, CEP could request waivers from the lenders in its bank group. Although the lenders may not provide a waiver, CEP may take additional steps in the event of not meeting the required ratios or in the event of a reduction in the combined borrowing base below its current level of $225.0 million at the future redetermination by the lenders. If it becomes necessary to pay debt down beyond operating cash flows, CEP could further reduce capital expenditures, continue to suspend quarterly distributions to unitholders, sell oil and natural gas properties or inventories, liquidate in-the-money derivative positions, reduce operating and administrative costs, or take additional steps to increase liquidity.

7. OIL AND NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	June 30, 2009	December 31, 2008
	(In 000 s)	
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 751,031	$ 729,898
Unproved property	38,156	38,293

Total property costs	789,187	768,191
Materials and supplies	5,225	4,587
Land	912	912
Total	795,324	773,690
Less: Accumulated depreciation, depletion and amortization	(143,249)	(111,171)
Natural gas properties and equipment, net	$ 652,075	$ 662,519

18

Table of Contents

Impairment of Oil and Natural Gas Properties

In the six months ended June 30, 2009, CEP recorded a charge of approximately $4.0 million to impair the value of certain of its wells located in the Woodford Shale in Oklahoma. This charge is included in depreciation, depletion and amortization in the Statement of Operations. This impairment was recorded because the carrying value of certain of the wells exceeded the fair value of the wells as measured by estimated cash flows reported in a third party reserve report that was based upon future expected oil and natural gas prices. The impairment is primarily caused by the impact of lower future expected natural gas prices. Cash flow estimates for the impairment testing exclude derivative instruments. As of June 30, 2009, CEP reviewed its other properties for impairment and the estimated undiscounted future cash flows exceeded the net capitalized costs, thus no impairment was required to be recognized. If oil and natural gas prices continue to significantly decline during 2009, the estimated undiscounted future cash flows for CEP s proved oil and natural gas properties may not exceed the net capitalized costs for the properties and an impairment may be required to be recognized.

Involuntary Conversion

In the first quarter 2008, a fire damaged the Company s field office located in Dewey, Oklahoma. The net book value of the building was $0.2 million. An insurance receivable of $0.4 million and a gain of $0.2 million were recorded for the involuntary conversion. The insurance proceeds of $0.4 million were collected in April 2008.

Useful Lives

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

8. RELATED PARTY TRANSACTIONS

Management Services Agreement

In November 2006, CEP entered into a management services agreement with Constellation Energy Partners Management, LLC (CEPM), a subsidiary of Constellation, to provide certain management, technical and administrative services. These services include legal, accounting and finance, engineering and technical, risk management, information technology and tax services, as well as acquisition services related to opportunities to acquire oil and natural gas reserves and related midstream assets. CEPM and its affiliates do not have any obligation to provide acquisition services or other services under the management services agreement, provided that CEPM may receive added compensation for providing CEP with services as a result of the management incentive interests it holds in CEP. Each quarter, CEPM charges CEP an amount for services provided to CEP. This amount is agreed to annually and includes a portion of the compensation paid by CEPM and its affiliates to personnel who spend time on CEP s business and affairs. The allocation of compensation expense for the chief executive officer, chief financial officer and chief accounting officer was fixed by agreement between the parties in 2008. As of January 1, 2009, these three officers, and CEP s general counsel, became direct employees of the Company. The allocation of compensation expense for other personnel of CEPM and its affiliates is determined based on the percentage of time spent by such personnel on CEP s business and affairs. The conflicts committee of the Company s board of managers reviews at least annually the services to be provided by CEPM and the costs to be charged to CEP under the management services agreement and reviews the cost allocation quarterly. The conflicts committee also determines if the amounts to be paid by the Company for the services to be performed are fair to and in the best interests of the Company. During the year, the cost allocation may be adjusted upwards to reflect additional services provided by CEPM and its affiliates or downwards to reflect the transition of services to CEP employees. These costs totaled approximately $0.6 million and $1.1 million for the six months ended June 30, 2009 and 2008, respectively. The costs charged to CEP under the management services agreement may be greater or less than the actual costs CEP would incur if the services were performed by an unaffiliated third party.

In June 2009, CEPM notified the CEP that it will terminate the management services agreement effective December 15, 2009. As a result, CEP submitted a plan to its lenders for managing its business after the termination of the agreement as required under the terms of its reserve-based credit facilities. The plan has received the requisite approval that was required under the Company s reserve-based credit facilities.

CEP had payables to Constellation of $0.4 million and $1.0 million as of June 30, 2009 and December 31, 2008, respectively. This payable balance is included in current liabilities in the accompanying balance sheets.

Credit Support Fee Agreements

As described further in Note 5, CEG and CEP entered into credit support fee agreement under which CEG guaranteed credit support for certain financial derivatives with three financial institutions. This credit support fee agreement has expired. For the six months ended June 30, 2008, CEG charged CEP $0.1 million for the credit support.

Natural Gas Purchases

Through March 31, 2009, CCG purchased natural gas from CEP in the Cherokee Basin. The arrangement was reviewed by the conflicts committee of CEP s board of managers. The committee found that the arrangement was fair to and in the best interests of CEP. For the six months ended June 30, 2009, and June 30, 2008, CCG paid CEP $5.7 million and $8.7 million for natural gas purchases, respectively.

In April 2009, Macquarie Cook Energy LLC (Macquarie Cook), a subsidiary of Sydney, Australia-based Macquarie Group, Ltd. (MQG) purchased the downstream natural gas trading operations of CEG. This included the CCG entity that purchased natural gas from CEP in the Cherokee Basin. Macquarie Cook will purchase natural gas from CEP in the Cherokee Basin for May 2009 through October 2009. CEP has received a guarantee from Macquarie Bank Limited for up to $8 million in purchases through December 31, 2011. Macquarie Cook is not a related party to CEP.

Management Incentive Interests

CEPM holds the management incentive interests in the Company. These management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in the Company s limited liability company agreement) has been achieved and certain other tests have been met. For the six months ended June 30, 2009, none of these applicable tests have been met, and, as a result, CEPM was not entitled to receive any management incentive interest distributions.

For the third quarter 2007, the Company increased its quarterly distribution rate to $0.5625 per unit. This increase in the distribution rate commenced a management incentive interest vesting period under the Company s limited liability company agreement. Through December 31, 2008, a cash reserve of $0.7 million had been established to fund future distributions on the management incentive interests. In February 2009, the Company reduced its quarterly distribution rate to $0.13 per unit. This decrease in the distribution rate terminated the initial management incentive interest vesting period. After the February 13, 2009 distribution was paid, this reserve of $0.7 million was reduced to zero.

CoLa Acquisition

As further described in Note 4, on March 31, 2008, the Company acquired 83 non-operated producing oil and natural gas wells in the Woodford Shale in the Arkoma Basin in Oklahoma from CoLa for approximately $50.2 million, including purchase price adjustments through June 30, 2009. CoLa is an affiliate of CEG, the Company s sponsor. The transaction was reviewed and approved by the Company s conflicts committee. In its review, the Company s conflicts committee considered various economic factors (including historical and estimated future production, estimated proved reserves, future pricing estimates and operating cost estimates) regarding the transaction, and determined that the transaction was fair to and in the best interests of the Company.

9. COMMITMENTS AND CONTINGENCIES

In the course of its normal business affairs, the Company is subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations and third-party litigation. As of June 30, 2009 and December 31, 2008, other than the matters discussed below, there were no matters which, in the opinion of management, would have a material adverse effect on the financial position, results of operations or cash flows of CEP, and its subsidiaries, taken as a whole.

Certain of the Company s wells in the Robinson s Bend Field are subject to a net profits interest (NPI) held by Torch Energy Royalty Trust (the Trust) (See Note 11). The royalty payment to the Trust is calculated using a sharing arrangement with a pricing formula that has had the effect of keeping our payments to the Trust lower than if such payments had been calculated based on prevailing market prices. CEP is uncertain of the financial impact of the NPI over the life of the Robinson s Bend Field as it has volumetric and price risk variables. However, in order to address a portion of the risk of the potential adverse impact on CEP s operating results from a termination of the sharing arrangement, Constellation Holdings, Inc. (CHI) contributed $8.0 million to CEP in exchange for all of CEP s Class D interests at the closing of its initial public offering to be used to protect the distributions to the common unit holders in the event the sharing arrangement is terminated. This contribution will be returned to CHI in 24 special quarterly distributions as long as the sharing agreement remains in effect for the distribution period. As a result of the initiation of the legal proceedings discussed in Note 11 and Note 16, the Class D interest special quarterly distributions have been suspended for all quarters commencing on or after January 1, 2008. This suspension includes $1,666,666.65 which represents the distributions that were suspended for the quarterly periods ended March, 31, 2009, and December 31, September 30, June 30, and March 31, 2008. The remaining undistributed amount of the Class D interests is $6.7 million. See Note 16 for additional information.

Table of Contents

10. ASSET RETIREMENT OBLIGATION

CEP follows SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 requires that the fair value of a liability for an asset retirement obligation (ARO) be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost (ARC) is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the ARC is allocated to expense using a systematic and rational method over the asset s useful life. The ARO s recorded by CEP relate to the plugging and abandonment of natural gas wells, and decommissioning of the gas gathering and processing 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 gas property balance.

The following table is a reconciliation of the ARO:

	June 30, 2009	December 31, 2008
	(In 000 s)	
Asset retirement obligation, beginning balance	$ 6,754	$ 6,163
Liabilities incurred from acquisition of the properties (Note 4)		56
Liabilities incurred	88	124
Accretion expense	157	411
Asset retirement obligation, ending balance	$ 6,999	$ 6,754

Additional 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 obligation. There have been no material expenditures for abandonments.

At June 30, 2009, and December 31, 2008, there were no assets legally restricted for purposes of settling existing asset retirement obligations.

11. NET PROFITS INTEREST

Certain of the Company s wells in the Robinson s Bend Field are subject to a non-operating NPI. The holder of the NPI, the Trust, does not have the right to receive production from the applicable wells in the Robinson s Bend Field. Instead, the Trust only has the right to receive a specified portion of the future natural gas sales revenues from specified wells as defined by the Net Overriding Royalty Conveyance Agreement. The Company records the NPI as an overriding royalty interest net in revenue in the Consolidated Statements of Operations.

Amounts due to the Trust with respect to NPI are comprised of the sum of the Net Proceeds and the Infill Net Proceeds, which are described below.

The Net Proceeds equal the lesser of (i) 95% of the net proceeds from 393 producing wells in the Robinson s Bend Field and (ii) the net proceeds from the sale of 912.5 MMcf of natural gas for the quarter. Net proceeds equal gross proceeds, currently calculated by reference to the gas purchase contract (for a description of the gas purchase contract, please read Item 1. Business Natural Gas Data Torch Royalty NPI The Gas Purchase Contract in the Company s Annual Report on Form 10-K for the year ended December 31, 2008), less specified costs attributable to the Robinson s Bend Assets. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (i) of the first sentence of this paragraph (the NPI Net Proceeds Calculation) include: (a) delay rentals, shut-in royalties and similar payments, (b) property, production, severance and similar taxes and related audit charges, (c) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies, (d) certain liabilities for environmental damage, personal injury and property damage, (e) certain litigation costs, (f) costs of environmental compliance, (g) specified operating costs incurred to produce hydrocarbons, (h) specified development costs (including costs to increase recoverable reserves or the timing of recovery of such reserves), (i) costs of specified lease renewals and extensions and unitization costs and (j) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (ii) of the first sentence of this paragraph include: (a) property, production, severance and similar taxes, (b) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies and (c) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. Net proceeds are calculated quarterly and any negative balance (expenses in excess of revenues) within the net proceeds calculation accumulates and is charged interest as described above.

The cumulative Net NPI Proceeds balance must be greater than $0 before any payments are made to the Trust. The cumulative Net Proceeds was a deficit for the six months ended June 30, 2009 and 2008. As a result, no payments were made to the Trust with respect to the NPI for the six months ended June 30, 2009 and 2008.

The calculation of the Infill Net Proceeds uses the same methodology as the NPI Net Proceeds Calculation described above except that the proceeds and costs are attributable not to the NPI Net Proceeds Wells, but to the remaining wells in the Robinson s Bend Field that are subject to the NPI and that have been drilled since the Trust was formed and wells that will be drilled (other than wells drilled to replace damaged or destroyed wells), in each case on leases subject to the NPI. The NPI in the Infill Wells entitles the Trust to receive 20% of the Infill Net Proceeds. There has never been a payout on the Infill Net Proceeds.

Termination of the Trust and Gas Purchase Contract

On January 29, 2008, the unitholders of the Trust voted to terminate the Trust and the trust agreement and authorized the Trustee to wind up, liquidate and distribute the assets held by the Trust under the terms of the trust agreement. The gas purchase contract, by its terms, was also terminated on January 29, 2008 as a result of the termination of the Trust.

With the gas purchase contract terminated, we are no longer obligated to sell gas produced from our interest in the Black Warrior Basin pursuant to the gas purchase contract. Notwithstanding the termination of the gas purchase contract, the NPI will continue to burden the Trust Wells, and it should continue to be calculated as if the gas purchase contract were still in effect, regardless of what proceeds may actually be received by us as the seller of the gas. Originally, the Trust indicated that it believed that the net profits interest would continue to be calculated as if the gas purchase contract was still in effect. The Trust, however, subsequently indicated that the documents creating the NPI were not clear as to this point. As a result, on January 25, 2008, Torch Royalty Company (Torch Royalty), Torch E&P Company (Torch E&P) and CEP (collectively, the Claimants) sent notice of a demand for arbitration before Judicial Arbitration and Mediation Services (JAMS) to Wilmington Trust Company, as Trustee (Trustee) for the Trust, and to Capital One, NA, as successor to Hibernia National Bank, as trustee for Torch Energy Louisiana Royalty Trust, pursuant to the operative dispute resolution provisions of the agreement governing the Trust, the NPI and the Conveyances (as defined below). The Claimants were working interest owners in certain oil and gas fields located in Texas, Louisiana and Alabama. The working interests owned by the other Claimants are similarly subject to net profit interests (the Other NPIs) that are also based on the gas purchase contract. In the arbitration demand, we and the other Claimants sought a declaratory judgment that the NPI payments as well as the payments owed in respect of the Other NPIs will continue to be calculated using the sharing arrangement under the gas purchase contract even though the Trust and the gas purchase contract have been terminated. In its response to the Claimant s arbitration demand, the Trustee took the position that the sharing arrangement under the gas purchase contract terminated upon the termination of that contract. On July 18, 2008, the arbitration panel issued its final award (the Final Award) which, among other things, found and concluded that the sharing arrangement and other pricing terms of the gas purchase contract will continue to control the amount owed to the holder of the NPI.

The Trust and Trust Venture filed a petition to vacate the Final Award (the Petition to Vacate) with the District Court of Harris County, Texas, 152nd Judicial District (the District Court) on October 16, 2008. The Claimants filed a motion to confirm the Final Award (the Motion to Confirm) with the District Court on November 5, 2008. On December 10, 2008, the District Court dismissed the Petition to Vacate and granted the Motion to Confirm, thus confirming the Final Award. The Company believes that any timely further appeal or request for other relief by the Trust and Trust Venture should have been filed by January 9, 2009. The Company is not aware of any filing having been made as of June 30, 2009. See Note 16 for additional information.

Water Gathering, Separation, and Disposal Costs

As a result of the termination of the Trust, certain water gathering, separation and disposal costs, which are a component of the NPI calculation, increased from $0.53 per barrel to $1.00 per barrel pursuant to the Water Gathering and Disposal Agreement dated August 9, 1990, as amended. The amounts of the water gathering, separation and disposal costs are set forth in the Water Gathering and Disposal Agreement, as amended. On January 8, 2009, the Company was served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in Alabama state court demanding an audited statement of revenues and expenses associated with the NPI, alleging a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserting that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit seeks unspecified damages and an accounting of the NPI. On February 9, 2009, the Company filed a motion to dismiss the lawsuit

22

and filed an arbitration proceeding against the Trust relating to the claims alleged in the lawsuit with Judicial Arbitration and Mediation Services (JAMS). On February 12, 2009, Trust Venture requested a stay of the arbitration proceeding. On February 25, 2009, the Circuit Court of Tuscaloosa County, Alabama denied the Company s motion to dismiss the lawsuit and also denied Trust Venture s motion to stay the arbitration proceeding. On April 10, 2009, the arbitration panel granted Trust Venture s motion to stay the arbitration proceeding until the conclusion of the related litigation that is currently pending in Alabama. As a result, the Alabama litigation is proceeding. The proceeding is in the discovery phase, with Trust Venture and the Trust asserting that discovery from the Trust be produced by the Trust voluntarily as it deems responsive without being subject to the jurisdiction of the Alabama Court. On June 12, 2009, the Company filed a Motion to Compel the Trust or Trust Venture to respond fully to its discovery requests to the Trust. The Company intends to defend itself vigorously with respect to the alleged claims. There can be no assurance as to the outcome or result of the lawsuit or the arbitration proceeding. The Company intends its forward-looking statements relating to the action to speak only as of the time of such statements and does not plan to update or revise them except to the extent that material information becomes available. See Note 16 for additional information.

12. ENVIRONMENTAL LIABILITY

CEP is subject to costs resulting from federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. As of June 30, 2009 and December 31, 2008, accrued environmental obligations were $0.3 million and $0.4 million, respectively. These obligations were classified as current liabilities on CEP s Consolidated Balance Sheet.

13. UNIT-BASED COMPENSATION

The Company recognized approximately $0.2 million and $0.1 million of non-cash expense related to grants made under its long-term incentive plan s unit-based compensation and executive inducement bonus program in the six months ended June 30, 2009, and June 30, 2008, respectively.

The Company recognized approximately $0.1 million of cash expense related to grants made under its omnibus incentive compensation program in the six months ended June 30, 2009. If the 2009 Omnibus Incentive Compensation Program is approved by unitholders, this $0.1 million in expense will be recorded as a non-cash expense as the liability for grants made under the program will be settled in restricted common units as opposed to cash.

Adoption of the Executive Inducement Bonus Program

An Executive Inducement Bonus Program was adopted and approved by the Company s Board of Managers on April 28, 2009. The plan was created without unitholder approval in reliance on the exemption provided in NYSE Arca rule 5.3(d)(5)(A). On May 7, 2009, CEP filed a registration statement with the SEC on Form S-8 for 300,000 common units associated with grants under this program made to the executives of CEP described below. After initial grants have been made, the only additional common units that can be issued under this program are for distribution rights in connection with distribution credits as described below.

Adoption of the 2009 Omnibus Incentive Compensation Plan

A 2009 Omnibus Incentive Compensation Plan containing 1,650,000 common units was adopted and approved by the Company s Board of Managers on April 28, 2009, subject to approval by the Company s common unitholders. If the common unitholders do not approve the plan, any grants made under the plan, including those discussed below, will be settled in cash based on the fair market value on the vesting date. Upon approval of the plan by the common unitholders, any outstanding grants will automatically convert into the same number of restricted common units which are settled in common units and not cash.

The adoption of the Executive Inducement Bonus Program and the 2009 Omnibus Incentive Compensation Plan, if approved by unitholders, will increase the number of authorized common units of the Company and will be considered when calculating diluted earnings per unit. The 2009 Omnibus Incentive Compensation Plan does not replace or affect the Company s LTIP that was adopted in November 2006 and it does not replace or affect the Executive Inducement Bonus Program discussed above. The 2009 Omnibus Incentive Compensation Plan contains 1,650,000 common units, of which approximately 646,427 units remain available for grants under the plan. The LTIP contains 450,000 common units, of which approximately 410,421 remain available for grants under the LTIP. The Executive Inducement Bonus Program is not expected to exceed 300,000 common units, of which approximately 132,517 units remain available for distribution rights in connection with distribution credits to the executives of CEP under the program.

23

Table of Contents

2009 Grants

Grants under the 2009 Omnibus Incentive Compensation Plan

On April 28, 2009, the Company s Board of Managers approved a grant of 26,979 notional units to each of the independent managers currently serving on the Board of Managers, each with an approximate grant-date value of $83,365 based on the closing price per unit on May 1, 2009. The grants were made under the 2009 Omnibus Incentive Compensation Plan pursuant to grant agreements, dated May 1, 2009, by and between the Company and each of Richard H. Bachmann, Richard S. Langdon and John N. Seitz. If the common unitholders do not approve the 2009 Omnibus Incentive Compensation Plan, the notional units will be settled in cash based on the fair market value on the vesting date. Upon approval of the 2009 Omnibus Incentive Compensation Plan by the common unitholders, the notional units so granted to the independent managers will automatically convert into restricted units. These grants vest on March 1, 2010.

On May 1, 2009, the Company made grants of an aggregate of 748,670 notional units under the 2009 Omnibus Incentive Compensation Plan to the four officers of CEP, with an approximate aggregate grant-date value of $2,313,390 based on the closing price per unit on May 1, 2009. The units will vest ratably over five years. If the common unitholders do not approve the 2009 Omnibus Incentive Compensation Plan, the notional units will be settled in cash based on the fair market value on the vesting date. Upon approval of the 2009 Omnibus Incentive Compensation Plan by the common unitholders, the notional units so granted to the four officers of CEP will automatically convert into restricted common units based on the vesting schedule for the notional units. As of June 30, 2009, a total of 33,625 notional units have been issued as distribution credits by the Company.

On May 1, 2009, the Company made grants of an aggregate of 140,341 notional units under the 2009 Omnibus Incentive Compensation Plan to seven new employees of the Company s wholly owned subsidiary, CEP Services Company, Inc (CEP Services), with an approximate aggregate grant-date value of $433,654 based on the closing price per unit on May 1, 2009. The units will vest ratably over five years. Each of these employees was formerly employed by CCG, an indirectly wholly owned subsidiary of CEG. These employees were involved in the performance of services to the Company under our management services agreement with CEPM and were hired by CEP Services to directly provide services to the Company and its subsidiaries. If the common unitholders do not approve the 2009 Omnibus Incentive Compensation Plan, the notional units will be settled in cash based on the fair market value on the vesting date. Upon approval of the 2009 Omnibus Incentive Compensation Plan by the common unitholders, the notional units so granted to the seven employees will automatically convert into restricted common units based on the vesting schedule for the notional units.

Prior to vesting, each notional unit and restricted common unit granted as described above under the 2009 Omnibus Incentive Compensation Plan carries the right to receive distribution credits when any distributions are made by the Company on its common units. Any distribution credits will accrue under the grants and be settled in cash or common units in the discretion of the Compensation Committee of the Board of Managers on the vesting date for the underlying notional unit or restricted common unit, as applicable. Upon approval of the 2009 Omnibus Incentive Compensation Plan by the common unitholders, any accrued distribution credits on the notional units will increase the number of restricted common units that are issued upon conversion of the notional units as described above.

Until any notional units granted under 2009 Omnibus Incentive Compensation Plan are converted into restricted common units upon unitholder approval, the notional units will be accounted for using the variable plan accounting method. Under the variable method, compensation costs will be measured using the quoted market price of the Company s common units on each measurement date and multiplying the compensation cost by the percentage of the vesting period served through the measurement date. Increases or decreases in the quoted market price of the common units between the date of the grant and each measurement date will result in a change in the compensation expense recognized for the notional units.

Grants under the Executive Inducement Bonus Program

On May 1, 2009, the Company made grants of an aggregate of 161,871 restricted common units under the Executive Inducement Bonus Program to induce four executives to become employed by the Company, with an approximate aggregate grant-date value of $500,181 based on the closing price per unit on May 1, 2009. The units will vest 50% on January 1, 2010, and 50% on January 1, 2011.

Prior to vesting, these restricted common units do not have the right to receive cash distributions paid by the Company on its common units. Instead, each such unvested restricted common unit carries the right to receive distribution credits when any distributions are made by the Company on its common units. Any distribution credits will accrue and be settled in cash or common units, in the discretion of the Compensation Committee of the Company s Board of Managers, upon the vesting of the underlying restricted common unit. As of June 30, 2009, a total of 5,612 restricted common units have been issued as distribution credits by the Company.

2008 Grants

Grants under the Long-Term Incentive Program

The Company granted 23,232 restricted common unit awards under the LTIP on August 1, 2008, to certain field employees of the Company in Alabama and Oklahoma. These units had a total fair market value of approximately $425,000 based on the average of the high and low trading price of the Company s units on NYSE Arca on the grant date. These service-based restricted units will vest on a three year ratable schedule beginning on August 1, 2009.

The Company granted 11,004 restricted common unit awards under the LTIP on March 1, 2008, to the independent, non-employee members of the Board of Managers. These units had a total fair market value of approximately $225,000 at the grant date. These service-based restricted units vested in full on March 1, 2009.

2007 Grants

Grants under the Long-Term Incentive Program

The Company granted 5,343 restricted common unit awards under the LTIP on September 14, 2007, to the independent, non-employee members of the Board of Managers. These units had a total fair market value of approximately $225,000 at the grant date. This amount was recognized over the vesting period. These restricted common units vested in full on March 1, 2008.

14. DISTRIBUTIONS TO UNITHOLDERS

Distributions through June 30, 2009

On May 15, 2009, the Company paid a distribution for the first quarter of 2009 to the unitholders of record at May 8, 2009. The distribution was paid to holders of common units and Class A units at a rate of $0.13 per unit.

On February 13, 2009, the Company paid a distribution for the fourth quarter of 2008 to the unitholders of record at February 6, 2009. The distribution was paid to holders of common units and Class A units at a rate of $0.13 per unit.

Distributions through June 30, 2008

On May 15, 2008, the Company paid a distribution for the first quarter of 2008 to the unitholders of record at May 8, 2008. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit.

On February 14, 2008, the Company paid a distribution for the fourth quarter of 2007 to the unitholders of record at February 7, 2008. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit. A distribution of $0.3 million was paid to the holder of the Company s Class D interests on February 14, 2008.

15. MEMBERS EQUITY

2009 Equity

At June 30, 2009, we had 451,142 Class A units and 22,105,826 Class B units outstanding, which included 23,232 unvested restricted common units issued under our Long-Term Incentive Plan and 167,484 unvested restricted common units issued under our Executive Inducement Bonus Program.

At June 30, 2009, we had granted 39,579 common units of the 450,000 common units available under our long-term incentive plan. Of these grants, 16,347 have vested.

At June 30, 2009, we had granted 167,484 common units of the 300,000 common units available under our Executive Inducement Bonus Program. Of these grants, none have vested.

2008 Equity

At June 30, 2008, we had 447,247 Class A units and 21,915,110 Class B units outstanding, which included 11,004 restricted unvested common units.

At June 30, 2008, we had granted 16,347 units of the 450,000 units available under our long-term incentive plan. Of these grants, 5,343 have vested.

Table of Contents

16. SUBSEQUENT EVENTS

The following subsequent events have occurred between July 1, 2009, and August 10, 2009:

Distribution to Unitholders

The Company has suspended its quarterly distributions to unitholders for the quarter ended June 30, 2009, to remain in compliance with the covenants associated with its reserve-based credit facilities. The distribution must remain suspended until the outstanding debt balance under its reserve-based credit facilities is less than 90% of the Company s combined borrowing base as determined by its lenders.

Torch NPI

On January 8, 2009, the Company was served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in Alabama state court demanding an audited statement of revenues and expenses associated with the NPI, alleging a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserting that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit seeks unspecified damages and an accounting of the NPI. On February 9, 2009, the Company filed a motion to dismiss the lawsuit and filed an arbitration proceeding against the Trust relating to the claims alleged in the lawsuit with Judicial Arbitration and Mediation Services (JAMS). On February 12, 2009 Trust Venture requested a stay of the arbitration proceeding. On February 25, 2009, the Circuit Court of Tuscaloosa County, Alabama denied the Company s motion to dismiss the lawsuit and also denied Trust Venture s motion to stay the arbitration proceeding. On April 1, 2009, the Circuit Court of Tuscaloosa County, Alabama again denied the Company s motion to stay the litigation in Alabama and again denied Trust Venture s motion to stay the arbitration proceeding. On April 10, 2009, the arbitration panel granted Trust Venture s motion to stay the arbitration proceeding until the conclusion of the related litigation that was pending in Alabama. On July 24, 2009, the arbitration proceeding was dismissed. As a result, the Alabama litigation is proceeding. The proceeding is in the discovery phase, with Trust Venture and the Trust asserting that discovery from the Trust be produced by the Trust voluntarily as it deems responsive without being subject to the jurisdiction of the Alabama Court. On June 12, 2009, the Company filed a Motion to Compel the Trust or Trust Venture to respond fully to its discovery requests to the Trust. On July 6, 2009, the Alabama Court granted the Company s motion, which Trust Venture and the Trust are further contesting. The Company intends to defend itself vigorously with respect to the alleged claims. There can be no assurance as to the outcome or result of the lawsuit or the arbitration proceeding. The Company intends its forward-looking statements relating to the action to speak only as of the time of such statements and does not plan to update or revise them except to the extent that material information becomes available.

Class D Interests

In connection with litigation related to the Torch NPI, the Company has suspended all quarterly cash contributions with respect to the Company s Class D interests. This suspension includes the $333,333.33 quarterly cash distribution for the three months ended June 30, 2009 and $1,666,666.65 which represents the distributions that were suspended for the quarterly periods ended March, 31, 2009, and December 31, September 30, June 30, and March 31, 2008. The remaining undistributed amount of the Class D interests is $6.7 million.

Unit-Based Compensation

The Company granted approximately 163,341 restricted common unit awards under the Long-Term Incentive Plan on August 1, 2009, to certain field employees of the Company in Alabama, Kansas, and Oklahoma. These units had a total fair market value of approximately $529,226 based on the average of the high and low trading price of the Company s units on NYSE Arca on the grant date. These service-based restricted units will vest on a three year ratable schedule beginning on August 1, 2010.

The Company granted approximately 49,215 notional unit awards under the 2009 Omnibus Incentive Compensation Program on August 1, 2009, to certain employees of the Company in Texas. These units had a total fair market value of approximately $163,887 based on the average of the closing price of the Company s units on NYSE Arca on the grant date. These service-based restricted units will vest on a five year ratable schedule beginning on August 1, 2010.

CoLa Acquisition

In July 2009, the Company received approximately $0.2 million from Cola for post-closing and title adjustments related to the CoLa acquisition. Under the purchase agreement, the Company had the right to assert, and CoLa had the right to attempt to cure, any title defects to the acquired wells until July 31, 2009. CoLa s post-closing payment obligations with respect to title defects and indemnities under the purchase agreement was secured, in part, by a guaranty from CCG delivered at closing. The maximum amount of the CCG guaranty was limited to (i) 20% of the purchase price, with respect to indemnity obligations, and (ii) with respect to title defect obligations, the amount of such title defects, such amount to be calculated as provided in the purchase agreement. The amount of CCG s guaranty with respect to title defect obligations has decreased as title curative were received and as CoLa received proceeds of production from the wells as to which payments of production proceeds had not commenced as of the closing date and which were attributable to periods prior to the effective time of the purchase agreement. No further title adjustments are expected and a guarantee no longer exists with respect to title defect obligations.

Derivative and Financial Instruments

In July 2009, the Company entered into various commodity swaps for 12,775,000 MMbtu of natural gas production in 2013 and 2014. The derivatives were entered into with RBS, Calyon and Bank of Nova Scotia. All of these derivatives will be accounted for as mark-to-market activities.

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 the Company s most recent Annual Report on Form 10-K.

Overview

We are a limited liability company formed by Constellation Energy Group, Inc. (Constellation) on February 7, 2005 to acquire oil and natural gas properties (E&P properties) as well as related midstream assets. Our oil and natural gas reserves are located in the Black Warrior Basin of Alabama, in the Cherokee Basin of Kansas and Oklahoma, and in the Woodford Shale in Oklahoma. Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders and over time to increase unitholder value. Our strategies for achieving this objective are to:

- make accretive acquisitions of E&P properties characterized by a high percentage of proved developed reserves with long-lived, stable production and low-risk drilling opportunities, which may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities;
- 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;
- realize value by opportunistically forming partnerships, participating in farm-out arrangements, joint operating agreements or other capital-efficient ventures to take advantage of our significant undeveloped acreage positions in the Cherokee Basin; and
- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through efficient hedging programs.

Our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing our current reserves and economically finding, developing and acquiring additional recoverable reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our business, financial condition and results of operations and our ability to pay quarterly cash distributions to our unitholders.

We also face the challenge of natural gas production declines. As a given well s initial reservoir pressures are depleted, natural gas production decreases. We attempt to overcome this natural decline both by drilling on our properties and acquiring additional reserves. We will continue to focus on reducing our costs to add reserves through drilling, well recompletions and acquisitions, as well as the corresponding costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. In accordance with our business plan, we intend to invest the capital necessary to maintain our production and our asset base over the long term. We will seek to maintain or grow our production and our asset base by pursuing both organic growth opportunities and acquisitions of producing reserves that are suitable for us.

We completed our initial public offering on November 20, 2006, and our common units, representing Class B limited liability company interests, are listed on the NYSE Arca, Inc. under the symbol CEP.

We have expanded our operations by completing the following acquisitions that we have included in our results of operations and cash flows beginning with the period of acquisition:

In March 2008, we completed an acquisition of 83 non-operated producing wells located in the Woodford Shale in Oklahoma (the CoLa Assets or CoLa Acquisition);

Table of Contents

- In September 2007, we completed the acquisition of additional coalbed methane properties in the Cherokee Basin of Oklahoma (the Newfield Assets or Newfield Acquisition);

- In July 2007, we completed an acquisition of additional oil and natural gas properties located in the Cherokee Basin in Oklahoma (the Amvest Acquisition); and

- In April 2007, we completed an acquisition of oil and natural gas properties located in the Cherokee Basin in Kansas and Oklahoma (the EnergyQuest Assets or EnergyQuest Acquisition).

These acquisitions have provided us with the option to pursue organic growth by drilling on proved undeveloped and unproved locations primarily in Osage County, Oklahoma.

Unless the context requires otherwise, any reference in this Quarterly Report on Form 10-Q to Constellation Energy Partners, we, our, us, CEI the successor company or the Company means Constellation Energy Partners LLC and its subsidiaries. References in this Quarterly Report on Form 10-Q to Constellation, CCG and CEPM are to Constellation Energy Group, Inc., Constellation Energy Commodities Group, Inc. and Constellation Energy Partners Management, 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;
- depreciation, depletion and amortization;
- write-off of deferred financing fees;
- impairment of long-lived assets;
- (gain) loss on sale of assets;
- (gain) loss from equity investment;
- unit-based compensation programs;
- accretion of asset retirement obligation;
- unrealized (gain) loss on natural gas derivatives; and

realized loss (gain) on cancelled natural gas derivatives.

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 cash distributions we 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 an 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 and others to assess:

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

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

Table of Contents

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

	For the Three Months Ended June 30, 2009	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
	(In 000 s)			
Reconciliation of Net Income to Adjusted EBITDA:				
Net income	$ (16,744)	$ (8,790)	$ 2,190	$ (7,289)
Adjusted by:				
Interest expense/(income), net	3,278	3,059	6,119	5,378
Depreciation, depletion and amortization	18,195	11,489	32,629	21,022
Accretion of asset retirement obligation	56	101	157	202
(Gain)/loss on sale of assets	(3)		14	(211)
(Gain)/loss on mark-to-market activities	12,134	15,033	(7,197)	17,989
Unit-based compensation programs	84	57	152	155
Unrealized loss/(gain) on natural gas derivatives		(410)	267	804
Adjusted EBITDA	$ 17,000	$ 20,539	$ 34,331	$ 38,050

Significant Operational Factors

Realized Prices. Our average realized price for the six months ended June 30, 2009, including hedges, was $8.22 per Mcfe. This realized price includes the impact of $7.2 million of unrealized gains on mark-to-market derivatives. Excluding the impact of the unrealized mark-to-market gains, the average realized price for the six months ended June 30, 2009 was $7.39 per Mcfe. Further deducting the cost of sales associated with third party gathering, average realized prices were $7.22 per Mcfe including hedges and $3.50 per Mcfe excluding hedges.

Production. Our production during the first six months of 2009 was approximately 8.6 Bcfe, or an average of 47,547 Mcfe per day.

Capital Expenditures and Drilling Results. During 2009, we spent approximately $20.6 million in cash capital expenditures for development activities in the Cherokee Basin. Our development activities were focused on completing the wells associated with our planned 2009 maintenance capital budget of approximately $30.5 million. This maintenance capital spending is intended to maintain our production rates, reserves, and asset base. Through the first six months of 2009, our drilling program has successfully replaced production at a rate sufficient to offset the natural decline rate from our existing properties. We now expect our total capital expenditures for 2009 to be between $23.0 million and $25.0 million, which is below our planned maintenance capital budget of $30.5 million.

In the Black Warrior Basin, we have stopped drilling activities due to low natural gas prices and the current costs to drill and complete wells in the Basin. We have completed 10 drilling locations at a total cost of approximately $1.2 million. These locations will be available to drill when it becomes economically favorable to do so.

In the Cherokee Basin, we drilled and completed 60 net wells and performed 17 net recompletions. We drilled 1 horizontal development dry hole. As of June 30, 2009, we have also started drilling 1 additional net well. Upon completion of this 1 net well, we do not currently expect to drill any additional wells during 2009.

Hedging Activities. Our hedging program uses derivatives to reduce the impact of commodity price volatility on our expected cash flows. Our current intention is to hedge, subject to the terms of our reserve-based credit facilities, up to 80% of our forecasted production for up to a five year period. Our management, however, may modify the hedging percentages and strategies as it deems appropriate for market conditions, the cost associated with the derivatives and other business strategies. In the first quarter of 2009, we designated all of our commodity and interest rate derivative positions that had been previously accounted for as hedges and will now account for all of our derivatives as mark-to-market activities.

We experience earnings volatility as a result of using the mark-to-market accounting method for all of our commodity derivatives used to hedge our exposure to changes in natural gas prices or basis differentials. This accounting treatment can cause earnings volatility as the positions for future natural gas production are marked-to-market. These non-cash unrealized gains or losses are included in our current Statement of Operations until the derivatives are cash settled as the commodities are produced and sold. We do not enter into speculative trading positions and we only use derivatives to lock in the future sales price for a portion of our expected natural gas production. Increases in the market price of natural gas relative to the fixed future sales price for our hedges result in unrealized, non-cash mark-to-market losses on those derivatives and lower reported net income. Decreases in the market price of natural gas relative to the fixed future sales price for our hedges result in unrealized, non-cash mark-to-market gains on those derivatives and higher reported net income. Although these gains and losses are required to be reported immediately in earnings as market prices change, the fair value of the related future physical natural gas sale is not marked-to-market and therefore is not reflected as Oil and Gas Sales or as an Accounts Receivable in our financial statements. This mismatch impacts our reported Result of Operations and our reported working capital position until the commodity derivatives are cash settled and the natural gas is produced and sold. Upon cash settlement of the derivatives, the sale of the physical commodity at then-current market prices offsets the previously reported mark-to-market gains or losses such that the cumulative net cash realized results in a net sale of the physical natural gas production at the fixed future sales price for our hedge. When our derivative positions are cash settled as the related commodities are produced and sold, the realized gains and losses of those derivative positions are included in our Statement of Operations as Oil and Gas Sales. Further detail of our commodity derivative positions and their accounting treatment is outlined starting on page 40.

Significant Market Factors

Events Impacting our Sponsor. Constellation owns all of our outstanding Class A units, approximately 5.9 million Class B Common Units, all of our Class D interests, and all of the Management Incentive Interests.

In June 2009, Constellation notified the CEP that it will terminate the management services agreement effective December 15, 2009. As a result, CEP submitted a plan to its lenders for managing its business after the termination of the agreement as required under the terms of its reserve-based credit facilities. The plan has received the requisite approval that was required under the Company s reserve-based credit facilities.

In March 2009, Constellation announced that it had impaired the fair value of its investment in CEP in part due to various factors including Constellation s financial condition and the possible sale of its investment in CEP.

In September 2008, Constellation announced that it had entered into a definitive merger agreement with MidAmerican Energy Holdings Company (MidAmerican) in which MidAmerican would purchase all of the outstanding shares of Constellation. At that time, Constellation publicly announced that it planned to proceed with its previously announced sale of its upstream gas assets. Constellation also acknowledged that it had not yet made any statements regarding its plans for its interests in us. At that time, Constellation reaffirmed the commitment to providing us services under the management services agreement. In December 2008, the merger agreement with MidAmerican was terminated and an alternative investment transaction with EDF Group was announced which is subject to receipt of required regulatory approvals and other standard closing conditions.

Strategic Advisor. In September 2008, we retained a financial advisor to assist in a review of strategic alternatives to enhance unitholder value. Tudor, Pickering, Holt & Co. Securities, Inc. has been engaged to provide independent advice to our management team and Board of Managers. We do not intend to disclose developments with respect to this review unless and until the Board of Managers has approved a course of action.

Transition of the Executive Management Team to CEP

In January 2009, our chief executive officer, chief operating officer, and president, chief financial officer and treasurer, and chief accounting officer and controller, were transitioned from being provided by CEPM under the management services agreement to direct employees of a subsidiary of CEP. In addition, a general counsel was appointed and transitioned from being an employee of CCG. This transition was done to better align our management team with the interests of our unitholders and to increase their focus on our business operations. Employment letter agreements were executed with these employees and were effective January 1, 2009. The details of the letter agreements for our chief executive officer, chief operating officer, and president and our chief financial officer and treasurer were filed as exhibits to a Current Report on Form 8-K on January 7, 2009. The details of the letter agreement for our general counsel were filed as an exhibit to our Annual Report on Form 10-K on February 27, 2009. In May 2009, formal employment agreements were executed and one-time inducement and long-term incentive grants were made. The details of the employment agreements and the inducement and long-term incentive grants were filed as exhibits to a Current Report on Form 8-K on May 4, 2009, and a Form 8-K/A filed on May 5, 2009.

As part of this transition, the compensation committee of the Board of Managers retained Hewitt Associates LLC to develop and review proposed compensation structures for the management team. Hewitt benchmarked compensation and benefits from among the following list:

a peer group of exploration and production companies, consisting of the following: Callon Petroleum Company, Carrizo Oil & Gas Inc., Delta Petroleum Corp., Edge Petroleum Corp., Goodrich Petroleum Corp., Legacy Reserves LP, McMoRan Exploration Company, Petroquest Energy, Inc., Rosetta Resources, Inc., Venoco, Inc., and Vanguard Natural Resources, LLC.

Hewitt proposed a compensation mix that would target total direct compensation for the team at competitive market median levels and provide for one-time, inducement sign-on bonuses. The total direct compensation includes a base salary

Table of Contents

and bonus award payouts based on future performance on selected performance measures. The performance targets are intended to be correlated to the creation of value for CEP unitholders and should balance growth, profitability, and efficient utilization of capital resources. The measures are expected to correspond to the Company s 2009 business plan and may include measures that are commonly used at other comparable E&P companies. The payout against the performance targets are intended to include a threshold level of minimum acceptable performance, a target level of performance, and a maximum level of performance that reflects the achievement of stretch goals. The proposed compensation mix is expected to be heavily weighted to time-based compensation, including restricted units of CEP. To the extent possible, units of CEP will be utilized to further align the interests of the management with unitholders. The overall structure and plan design to be used in 2009 should ensure alignment with our business strategy.

Through June 30, 2009, seven employees and certain services have been transitioned from being provided by CEPM under the management services agreement to CEP. By December 15, 2009, we expect that the remaining employees and services currently being provided by CEPM under the management services agreement will be transitioned to CEP.

Results of Operations

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

	For the Three Months Ended				For the Six Months Ended			
	(Dollars in 000 s)							
	June 30, 2009	June 30, 2008	Variance $	Variance %	June 30, 2009	June 30, 2008	Variance $	Variance %
Revenues:								
Oil and gas sales	$ 30,698	$ 38,994	$ (8,296)	(21.3)%	$ 63,560	$ 70,419	$ (6,859)	(9.7)%
Gain (Loss) from mark-to-market activities	(12,134)	(15,033)	2,899	(19.3)%	7,197	(17,989)	25,186	(140.0)%
Total revenues	18,564	23,961	(5,397)	(22.5)%	70,757	52,430	18,327	35.0%
Operating expenses:								
Lease operating expenses	8,289	9,209	(920)	(10.0)%	17,074	18,273	(1,199)	(6.6)%
Cost of sales	612	2,239	(1,627)	(72.7)%	1,444	3,387	(1,943)	(57.4)%
Production taxes	560	2,885	(2,325)	(80.6)%	1,530	4,550	(3,020)	(66.4)%
General and administrative expenses	4,311	3,787	524	13.8%	9,647	7,122	2,525	35.5%
(Gain) loss on sale of asset	(3)		(3)		14	(211)	225	(106.6)%
Depreciation, depletion and amortization	18,195	11,489	6,706	58.4%	32,629	21,022	11,607	55.2%
Accretion expenses	56	101	(45)	(44.6)%	157	202	(45)	(22.3)%
Total operating expenses	32,020	29,710	2,310	7.8%	62,495	54,345	8,150	15.0%
Other expenses (income):								
Interest expense	3,278	3,102	176	5.7%	6,121	5,662	459	8.1%
Interest income		(43)	43	(100.0)%	(2)	(284)	282	(99.3)%
Other (income) expense	10	(18)	28	(155.6)%	(47)	(4)	(43)	1,075.0%
Total other expenses (income)	3,288	3,041	247	8.1%	6,072	5,374	698	13.0%
Total expenses	35,308	32,751	2,557	7.8%	68,567	59,719	8,848	14.8%
Net income (loss)	$ (16,744)	$ (8,790)	$ (7,954)	90.5%	$ 2,190	$ (7,289)	$ 9,479	(130.0)%
Net production:								
Total production (MMcfe)	4,242	4,422	(180)	(4.1)%	8,606	8,465	141	1.7%
Average daily production (Mcfe/d)	46,615	48,593	(1,978)	(4.1)%	47,547	46,511	1,036	2.2%

Average sales prices:																
Price per Mcfe including hedges[a]	$	4.38[a]	$	5.42 [a]	$	(1.04)	(19.2)%	$	8.22[a]	$	6.19[a]	$	2.03	32.7%
Price per Mcfe excluding hedges	$	3.16	$	10.42	$	(7.26)	(69.6)%	$	3.67	$	9.22	$	(5.55)	(60.2)%
Average unit costs per Mcfe:														
Field operating expenses[b]	$	2.09	$	2.73	$	(0.64)	(23.4)%	$	2.16	$	2.70	$	(0.54)	(20.0)%
Lease operating expenses	$	1.95	$	2.08	$	(0.13)	(6.2)%	$	1.98	$	2.16	$	(0.18)	(8.3)%
Production taxes	$	0.13	$	0.65	$	(0.52)	(79.8)%	$	0.18	$	0.54	$	(0.36)	(66.9)%
General and administrative expenses	$	1.02	$	0.86	$	0.16	18.7%	$	1.12	$	0.84	$	0.28	33.2%
Depreciation, depletion and amortization[c]	$	4.29	$	2.60	$	1.69	65.1%	$	3.79	$	2.48	$	1.31	52.7%

[a] Price per Mcfe including hedges includes realized and unrealized mark-to-market gains on derivative transactions that did not qualify for hedge accounting treatment.

[b] Field operating expenses include lease operating expenses and production taxes.

[c] Depreciation, depletion and amortization includes non-cash impairments of oil and natural gas assets. Excluding impairments, the three months ended June 30, 2009 cost per Mcfe was $3.45 and $3.33 per Mcfe for the six months ended June 30, 2009.

Three months ended June 30, 2009 compared to three months June 30, 2008

Oil and natural gas sales. Oil and natural gas sales decreased $8.3 million, or 21.3%, to $30.7 million for the three months ended June 30, 2009 as compared to $39.0 million for the same period in 2008. Of this decrease, $1.9 million was attributable to decreased production volumes and $30.8 million was attributable to lower market prices for oil and natural gas, offset by $24.4 million in gains from our hedging program. Production for the three months ended June 30, 2009 was 4.3 Bcfe, which was 0.2 Bcfe lower than the same period in 2008. Of the decrease, 0.2 Bcfe was a result of the decline in production associated with our 83 wellbores in the Woodford Shale. Our production in the Black Warrior Basin was less than 0.1 Bcfe lower in 2009 than in 2008, which was offset by result of increased production of less than 0.1 Bcfe due to our drilling programs in the Cherokee Basin. Our 2008 and 2009 maintenance drilling program has substantially offset the natural decline rate of production associated with our existing wells. We hedged approximately 81% of our actual production during the second quarter of 2009 and approximately 88% of our actual production during the same period in 2008.

As discussed below, the gain from our unrealized non-cash mark-to-market activities increased $2.9 million for the three months ended June 30, 2009, as compared to the same period in 2008. Our realized prices before our hedging program decreased from 2009 to 2008 primarily due to significantly lower market prices for oil and natural gas. This was offset by our hedging program and the mark-to-market gains discussed below.

Hedging and mark-to-market activities. As of June 30, 2009, all of our swaps, put option, and basis swaps are accounted for as mark-to-market derivatives. For the three months ended June 30, 2009, the unrealized non-cash mark-to-market loss was approximately $12.1 million as compared to an unrealized non-cash $15.0 million loss for the same period in 2008. This 2009 non-cash loss represents approximately $13.1 million from the impact of higher expected future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities offset by a $1.0 million increase for non-performance risk related to our counterparties.

Prior to the first quarter 2009, we entered into cash flow hedges in an effort to reduce our exposure to fluctuations in natural gas prices. For the three months ended June 30, 2008, we recognized a gain of approximately $0.4 million related to hedge ineffectiveness.

Cash settlements of hedges were received for our commodity derivatives for approximately $17.4 million for the three months ended June 30, 2009. Cash settlements of hedges were received for our commodity derivatives for approximately $7.4 million for the three months ended June 30, 2008. This difference is primarily due to significantly lower market prices for natural gas during 2009.

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

For the three months ended June 30, 2009, lease operating expenses decreased $0.9 million, or 10.0%, to $8.3 million, compared to expenses of $9.2 million for the same period in 2008. This decrease in lease operating expenses is primarily related to $0.8 million in lower total spending in the Cherokee Basin and $0.1 million in lower total spending in the Woodford Shale. Our lease operating expenses in the Black Warrior Basin were essentially level between 2009 and the same period in 2008. By category, our lease operating expenses were lower in 2009 as compared to 2008 by $0.9 million because of a $0.7 million decrease in well servicing costs, a $0.5 million decrease in road and lease maintenance, a $0.1 million decrease in costs for our non-operated Woodford Shale properties, and a $0.1 million decrease in expenses associated with the Dewey office fire, offset by a $0.4 million increase in treating and compression costs and a $0.1 million increase in power and fuel costs.

For the three months ended June 30, 2009, per unit lease operating expenses were $1.95 per Mcfe compared to $2.08 per Mcfe for the same period in 2008. This decrease is attributable to a decrease in total spending of approximately 10% in 2009 as compared the same period in 2008 offset by 4.1% lower production in 2009 as compared to the same period in 2008. Our per unit operating costs decreased approximately 8% in the Cherokee Basin from $2.34 per Mcfe in 2008 to $2.16 per Mcfe in 2009 as a result of $0.8 million in lower total spending and essentially level production volumes.

Table of Contents

For the three months ended June 30, 2009, production taxes decreased $2.3 million, or 80.6%, to $0.6 million, compared to expenses of $2.9 million for the same period in 2008. This decrease was primarily the result of significantly lower market prices for oil and natural gas in 2009 and by the impact of production taxes on 0.2 Bcfe in lower production.

Cost of sales. For the three months ended June 30, 2009, cost of sales decreased by $1.6 million, or 72.7%, to $0.6 million, compared to $2.2 million for the same period in 2008. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower natural gas prices as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, costs billed by CEPM under our management services agreement and other costs not directly associated with field operations.

General and administrative expenses increased $0.5 million, or 13.8%, to $4.3 million for the three months ended June 30, 2009, as compared to $3.8 million for the same period in 2008. Our general and administrative expenses were higher in 2009 as compared to 2008 because of $1.3 million in labor costs and $0.1 million in administrative costs in Tulsa, offset by $0.5 million in legal fees primarily associated with the Torch litigation that occurred in 2008 and $0.4 million in lower CEPM charges for labor. For the three months ended June 30, 2009 and 2008, CEPM allocated $0.3 million and $0.7 million, respectively, in expenses to us for labor and other charges through the management services agreement.

Our per unit costs were $1.02 per Mcfe for the three months ended June 30, 2009 compared to $0.86 per Mcfe for the same period in 2008. This increase is attributable to an increase in total spending of approximately $0.5 million combined with the effect of 0.2 Bcfe in lower production. This increased level of spending is expected to continue in 2009 as services continue to be transitioned from being provided by CEPM under the management services agreement to CEP.

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. Assuming everything else remains unchanged, as natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the three months ended June 30, 2009 was $18.2 million, or $4.29 per Mcfe, compared to $11.5 million, or $2.60 per Mcfe, for the same period in 2008. This increase in 2009 depreciation, depletion, and amortization reflects the increased basis in our assets resulting from the cost of our asset acquisitions in the Woodford Shale, additional capital expenditures for our development drilling programs, a lower year-end 2008 reserve base primarily due to price-related reserve revisions, an impairment of $3.6 million for certain of our wells in the Woodford Shale, and a 0.2 Bcfe decrease in production volumes in the Woodford Shale during 2009 as compared to 2008. The impairment was primarily caused by the impact of lower natural gas prices on estimated future cash flows for the Woodford Shale wells. We calculate depletion using units-of-production under the successful efforts method of accounting except for our other assets which are depreciated using the straight line basis.

Interest expense. Interest expense for the three months ended June 30, 2009 increased $0.2 million to $3.3 million as compared to approximately $3.1 million in interest expense for same period in 2008. This increase was primarily due to $0.6 million in non-cash mark-to-market losses on our interest rate swaps that are accounted for as market-to-market activities. This increase was offset by lower market interest rates of $1.2 million and higher swap settlements of $0.8 million during 2009 as compared to the same period in 2008. Our borrowings under our reserve-based credit facilities increased in 2009 as compared to the same period in 2008 to finance capital expenditures and working capital needs. At June 30, 2009, we had an outstanding balance under our credit facilities of $220.0 million as compared to $216.0 million at June 30, 2008.

Interest income. Interest income for the three months ended June 30, 2009 decreased less than $0.1 million to zero as compared to less than $0.1 million in interest income for same period in 2008. During 2008, we earned interest income by utilizing overnight investments on our excess cash balances. In 2009, we discontinued our overnight investments to participate in a program sponsored by the FDIC s Transaction Account Guarantee Program to provide unlimited insurance coverage for transaction account balances that do not earn interest. This program is currently available until December 31, 2009.

Accumulated other comprehensive income. Accumulated other comprehensive income, shown on our consolidated balance sheets, reflects the changes in the fair market value of our open hedge positions. At June 30, 2009, the balance was an unrealized gain of $46.5 million compared to an unrealized gain of $50.1 million at December 31, 2008. This decrease reflects the settlements during the second quarter of 2009 related to amounts previously included in locked accumulated other comprehensive income associated with our hedging positions previously accounted for as cash flow hedges under SFAS 133. All of our derivative positions are now accounted for as mark-to-market activities and the remaining balance in accumulated other comprehensive income will be amortized to earnings as the positions settle in the future.

Table of Contents

The change in Accumulated other comprehensive income (loss) is shown in our consolidated statements of operations and comprehensive income (loss) as an unrealized loss of $11.4 million for the three months ended June 30, 2009, and as an unrealized loss of $94.8 million for the same period in 2008. This change is primarily due to the impact of the amortization of locked accumulated other comprehensive income as we realize an offsetting gain upon the physical sale of natural gas production for which second quarter 2009 hedges have fixed the future sales price.

Six months ended June 30, 2009 compared to the six months ended June 30, 2008

Oil and gas sales. Oil and natural gas sales decreased $6.9 million, or 9.7%, to $63.5 million for the six months ended June 30, 2009 as compared to $70.4 million for the same period in 2008. Of this decrease, $1.3 million was attributable to increased production volumes and $39.6 million was attributable to gains from our hedging program, offset by $47.8 million in significantly lower market prices for oil and natural gas. Production for the six months ended June 30, 2009 was 8.6 Bcfe, which was 0.1 Bcfe higher than the same period in 2008. This increase is due to our drilling and workover programs in the Cherokee Basin. Our 2008 and 2009 maintenance drilling program has substantially offset the natural decline rate of production associated with our existing wells. Our production in the Black Warrior Basin was essentially flat and our production in the Woodford Shale was slightly higher as this acquisition closed March 31, 2008. We hedged approximately 81% of our actual production during the first six months of 2009 and approximately 92% of our actual production during the same period in 2008.

As discussed below, the gain from our unrealized non-cash mark-to-market activities increased $25.2 million for the six months ended June 30, 2009, as compared to the same period in 2008. Our realized prices before our hedging program decreased from 2009 to 2008 primarily due to significantly lower market prices for oil and natural gas. This was offset by our hedging program and the mark-to-market gains discussed below.

Hedging and mark-to-market activities. As of June 30, 2009, all of our swaps, put option, and basis swaps are accounted for as mark-to-market derivatives. For the six months ended June 30, 2009, the unrealized non-cash mark-to-market gain was approximately $7.2 million as compared to an unrealized non-cash $18.0 million loss for the same period in 2008. This 2009 non-cash gain represents approximately $7.1 million from the impact of lower expected future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities and a $0.1 million increase for non-performance risk related to our counterparties.

Prior to the first quarter 2009, we entered into cash flow hedges in an effort to reduce our exposure to fluctuations in natural gas prices. For the six months ended June 30, 2009, we recognized a loss of approximately $0.3 million related to hedge ineffectiveness. For the six months ended June 30, 2008, we recognized a gain of approximately $0.4 million related to hedge ineffectiveness.

Cash settlements of hedges were received for our commodity derivatives for approximately $32.3 million for the six months ended June 30, 2009. Cash settlements of hedges were paid for our commodity derivatives for approximately $6.8 million for the six months ended June 30, 2008. This difference is primarily due to significantly lower market prices for natural gas during 2009.

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

For the six months ended June 30, 2009, lease operating expenses decreased $1.2 million, or 6.6%, to $17.1 million, compared to expenses of $18.3 million for the six months ended June 30, 2008. By category, our lease operating expenses were lower in the six months ended June 30, 2009, as compared to the six months ended June 30, 2008, because of a $0.7 million decrease in field reorganization expenses in Tulsa, $0.5 million decrease in road and lease maintenance, $0.4 million decrease in contract labor, and a $0.1 million decrease in expenses associated with the Dewey office fire, offset by an increase of $0.5 million in transportation and gathering charges.

For the six months ended June 30, 2009, per unit lease operating expenses were $1.98 per Mcfe compared to $2.16 per Mcfe for the six months ended June 30, 2008. Our per unit costs decreased in 2009 as compared to the same period in 2008 because of 0.1 Bcfe of increased production in 2009 and fewer weather-related and specific field office events that occurred in the Cherokee Basin in 2008. During the six months ended June 30, 2008, the weather-related and specific field office events impacting our lease operating expenses in the Cherokee Basin were $0.5 million in repair costs to restore production after a significant winter ice storm in Oklahoma, $0.7 million of field reorganization expenses in Tulsa, $0.3 million in costs associated with the final Newfield settlement under the transition services agreement, and $0.1 million in incremental expenses associated with the Dewey office fire, surface damages, shut-in payments, and environmental costs.

For the six months ended June 30, 2009, production taxes decreased $3.0 million, or 66.4%, to $1.5 million, compared to expenses of $4.6 million for the six months ended June 30, 2008. This decrease was primarily the result of significantly lower market prices for oil and natural gas in 2009 and by the impact of production taxes on 0.1 Bcfe in higher production in Oklahoma.

Cost of Sales. For the six months ended June 30, 2009, cost of sales decreased by $2.0 million, or 57.4%, to $1.4 million, compared to $3.4 million for the same period in 2008. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower natural gas prices as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, costs billed by CEPM under our management services agreement and other costs not directly associated with field operations. General and administrative expenses increased $2.5 million, or 35.5%, to $9.6 million for the six months ended June 30, 2009, as compared to $7.1 million for the six months ended June 30, 2008. This increase was primarily due to costs associated with transitioning services from CEPM to CEP. Our general and administrative expenses were higher in the six months ended June 30, 2009, as compared to the six months ended June 30, 2008, because of $3.0 million in higher labor, bonus, benefits, and unit-based compensation, $0.2 million in professional services including reservoir engineering, $0.1 million in insurance, offset by $0.4 million in legal fees, $0.3 million in lower allocations from CEPM, and $0.1 million in audit and tax fees. For the six months ended June 30, 2009 and 2008, CEPM allocated $0.9 million and $1.2 million, respectively, in expenses to us for labor and other charges.

Our per unit costs were $1.12 per Mcfe for the six months ended June 30, 2009 compared to $0.84 per Mcfe for the six months ended June 30, 2008. This increase is attributable to an increase in total spending of approximately $2.6 million offset by 0.1 Bcfe in higher production. This level of spending is expected to continue in 2009 as services continue to be transitioned from being provided by CEPM under the management services agreement to CEP.

Gain/loss on sale of asset. Our gain/loss on the sale of assets decreased $0.2 million, or 106.6%, to less than a $0.1 million loss for the three months ended June 30, 2009, as compared to a gain of $0.2 million for the same period in 2008. In 2009, we sold surplus equipment at loss of less than $0.1 million. In 2008, a fire damaged our field office located in Dewey, Oklahoma. A gain of $0.2 million was recorded for the involuntary conversion as the insurance proceeds of $0.4 million exceeded the $0.2 million book value of the building.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs.

Our depreciation, depletion and amortization expense for the six months ended June 30, 2009 was $32.6 million, or $3.79 per Mcfe, compared to $21.0 million, or $2.48 per Mcfe, for the same period in 2008. This increase in 2009 depreciation, depletion, and amortization reflects the increased basis in our assets resulting from the cost of our asset acquisitions in the Woodford Shale, additional capital expenditures for our development drilling programs, a lower year-end 2008 reserve base primarily due to price-related reserve revisions, and an impairment of $4.0 million for certain of our wells in the Woodford Shale offset by a 0.1 Bcfe increase in production volumes in the Cherokee Basin and Woodford Shale during 2009 as compared to 2008. The impairment was primarily caused by the impact of lower natural gas prices on estimated future cash flows for the Woodford Shale wells. We calculate depletion using units-of-production under the successful efforts method of accounting except for our other assets which are depreciated using the straight line basis.

Interest expense. Interest expense for the six months ended June 30, 2009 increased $0.5 million to $6.1 million as compared to approximately $5.6 million in interest expense for the six months ended June 30, 2008. This increase was primarily due to $0.9 million in non-cash mark-to-market losses on our interest rate swaps that are accounted for as market-to-market activities. This increase was offset by lower market interest rates of $1.9 million, higher swap settlements of $1.4 million, and lower capitalized interest of $0.1 million during 2009 as compared to the same period in 2008. Our borrowings under our reserve-based credit facilities increased in 2009 as compared to the same period in 2008 to finance capital expenditures and working capital needs. At June 30, 2009, we had an outstanding balance under our credit facilities of $220.0 million as compared to $216.0 million at June 30, 2008. The average interest rate on our outstanding debt was approximately 4.9% in 2009.

Interest income. Interest income for the six months ended June 30, 2009 decreased $0.3 million to less than $0.1 million as compared to approximately $0.3 million in interest income for same period in 2008. During the six months ended June 30, 2008, we earned interest income by utilizing overnight investments on our excess cash balances. In 2009, we discontinued our overnight investments to participate in a program sponsored by the FDIC s Transaction Account Guarantee Program to provide unlimited insurance coverage for transaction account balances that do not earn interest. This program is currently available until December 31, 2009. In March 2008, we received $0.1 million in interest on payment balances from receivables related to the sales of natural gas included in the Torch NPI escrow account. Effective with the termination of the Trust, the escrow account arrangement also terminated and all payments for natural gas sales were directly received by us.

Accumulated other comprehensive income. The change in Accumulated other comprehensive income (loss) is shown in our consolidated statements of operations and comprehensive income (loss) as an unrealized loss of $3.6 million for the six months ended June 30, 2009, and as an unrealized loss of $143.0 million for the six months ended June 30, 2008. This change is primarily due to the impact of the decrease in expected future market prices for natural gas on our outstanding commodity derivatives accounted for as cash flow hedges and the impact of the amortization of locked accumulated other comprehensive income as we realize an offsetting gain upon the physical sale of natural gas production for which second quarter 2009 hedges have fixed the future sales price.

Liquidity and Capital Resources

During 2009, we utilized proceeds from borrowings under our credit facilities and cash flow from operations as our primary sources of capital. Our primary use of capital during 2009 has been for the development of existing oil and natural gas properties in the Cherokee Basin. As we pursue our business plans, we will be monitoring the capital resources available to us to meet our future financial obligations and planned capital expenditures. 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. Our results will not be fully impacted by significant increases or decreases in natural gas prices because of our hedging program, which is further discussed on page 39. Based upon our current business plan, we expect to generate operating cash flows in excess of our remaining 2009 maintenance capital expenditures and working capital needs. This excess cash flow may be used to reduce our debt levels.

Our reserve-based credit facilities currently provide only limited availability to finance future maintenance capital expenditures and other working capital needs. As of June 30, 2009, our total borrowing base under our reserve-based credit facilities was $225.0 million. At June 30, 2009, we had $220.0 million of debt outstanding under the reserve-based credit facilities and $5.0 million in unused borrowing capacity. Since our outstanding debt balance under our credit facilities exceeds 90% of our borrowing base, we are currently restricted from making cash distributions to our unitholders. Our credit facilities mature in October 2010. In the first quarter of 2008, we filed a shelf registration statement with the SEC to register up to $1.0 billion of debt or equity securities to fund future expansion capital expenditures. This registration statement is now effective. There is no guarantee that securities can or will be issued under the registration statement. Based on current financial market conditions and market prices for oil and natural gas, we expect capital markets to remain constrained which will make issuing additional debt or equity securities difficult or not possible at all. Our current credit facilities are also subject to future borrowing base redeterminations and must be renewed or replaced before October 2010.

For 2009, we expect to fund our working capital needs and our remaining maintenance capital expenditures with cash flow from operations. Our expectation is that we will manage our business to operate within the cash flows that are generated and we currently intend to retain any available surplus cash as we execute our operating plan during the remainder of 2009. This surplus cash may be used to reduce our debt levels. In response to low natural gas prices, we have stopped all drilling activities in the Black Warrior Basin and have completed substantially all of our 2009 drilling activities in the Cherokee Basin. We expect that our recently announced suspension of our quarterly distribution and the reduction in our total planned capital expenditures will provide additional liquidity to fund our operations and to pay down debt. Our future quarterly distribution to unitholders cannot resume until our outstanding debt balance is less than 90% of our borrowing base as determined by our lenders. We are subject to additional future borrowing base redeterminations and cannot forecast at what level our lenders will set our future borrowing base. However, after our outstanding debt balance is less than 90% of our borrowing base, we will evaluate the resumption of our quarterly distribution to unitholders. We anticipate that our distribution will remain suspended until our debt levels are reduced and we resume capital spending at maintenance levels. Any future quarterly distributions must be approved by our Board of Managers.

Reserve-Based Credit Facilities

On March 28, 2008, we entered into a new $500.0 million secured credit facility with The Royal Bank of Scotland as administrative agent and a syndicate of lenders. The amount available for borrowing at any one time under the Credit Facility is limited to the borrowing base for our properties other than in the State of Alabama. As of June 30, 2009, the borrowing base for this Credit Facility is $115.0 million. On March 28, 2008, we also amended and restated our existing $200.0 million credit facility by entering into an amended and restated credit agreement with The Royal Bank of Scotland as administrative

agent and a syndicate of lenders. The amount available for borrowing at any one time under the Amended and Restated Credit Facility is limited to the borrowing base for our properties in the State of Alabama. As of June 30, 2009, the borrowing base on the Amended and Restated Credit Facility is $110.0 million. Both of our credit facilities will mature on October 31, 2010 and the $220.0 million due under these facilities become a current liability on October 31, 2009. We will need to renew or replace these credit facilities prior to their maturity date. There is no guarantee that we will be able to renew these facilities. Even if we do renew or replace these facilities, it may not be possible to do so with similar borrowing costs, terms, or covenants or at the same borrowing base.

As of August 10, 2009, we had $220.0 million in debt outstanding under these two credit facilities. The amount available for borrowing at any one time is limited to the borrowing base under each facility. 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 prepared by reserve engineers, together with, among other things, the oil and natural gas prices at such time. Any increase in the borrowing base will have to be approved by all of the lenders in the syndicate and any decrease in the borrowing base will have to be approved by lenders holding at least 66 $^{2}/3$% of the commitments. Our aggregate borrowing base of $225.0 million may be redetermined again prior to the maturity of the two credit facilities in October 2010. It is possible that our borrowing base could decrease because of lower oil and natural gas prices or other factors.

Our reserve-based credit facilities contain similar commercial terms with the same lenders participating in the same applicable percentages. The current lenders and their percentage commitments in the two facilities are: The Royal Bank of Scotland (23.32%), BNP Paribas (22.55%), Wachovia Bank, N.A. (14.55%), Bank of Nova Scotia (17.00%), Calyon (15.05%), and Societe Generale (7.53%). A cross-default feature provides that an event of default under one agreement constitutes an event of default under the other. Our obligations under our credit facilities are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. We are required to maintain the mortgages on properties representing at least 85% of our proved producing and proved non-producing reserves. Additionally, the obligations under the credit facilities are guaranteed by all of our operating subsidiaries and any future material subsidiaries.

Borrowings under our credit facilities are available to us for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the credit facility, working capital and general limited liability company purposes. A sub-limit of $20.0 million of the facility applies for letters of credit.

At our election, interest will be determined by reference to:

- LIBOR plus an applicable margin between 1.25% and 2.00% per annum based on utilization; or

- a domestic bank rate plus an applicable margin between 0.25% and 1.00% per annum based on utilization.

Interest will generally be payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

Our credit facilities contain various covenants that limit our ability to:

- incur indebtedness;

- grant certain liens;

- make certain loans, acquisitions, capital expenditures and investments;

- make distributions other than from available cash;

- merge or consolidate; or

engage in certain asset dispositions, including a sale of all or substantially all of our assets.

Our credit facilities also contain covenants that, among other things, require us to maintain specified ratios or conditions as follows:

debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus 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, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not greater than 3.5 to 1.0; and

Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and

Table of Contents

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 obligations under the credit facilities, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under Statement of Financial Accounting Standards (SFAS) 133 and SFAS 143 (including the current liabilities in respect of the termination of natural gas and interest rate swaps).

A failure to maintain the foregoing ratios could result in an acceleration of any indebtedness in excess of $1.0 million and would constitute an event of default that would prohibit us from making distributions.

We have the ability to borrow under our credit facilities to pay distributions to unitholders as long as there has not been a default or event of default and if the amount of borrowings outstanding under our credit facilities is less than 90% of the borrowing base. As of June 30, 2009, our amount of borrowings outstanding under our credit facilities is greater than 90% of the borrowing base so that no cash distributions can be made to our unitholders.

If an event of default exists under our credit facilities, the lenders will be able to accelerate the maturity of the credit facility and exercise other customary rights and remedies. Each of the following is an event of default:

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;

- a representation or warranty made under the loan documents or in any report or other instrument furnished there under is incorrect when made; and

- failure to perform or otherwise comply with the covenants in the credit facility or other loan documents, subject, in certain instances, to certain grace periods, which include but are not limited to covenants that:

  - Constellation and its affiliates maintain the right to elect our Class A Managers; and

  - we obtain the approval of the administrative agent (such approval not to be unreasonably withheld or delayed) of any management services plan upon the termination of the management services agreement with CEPM;

- any event occurs that permits or causes the acceleration of the indebtedness;

- bankruptcy or insolvency events involving us or our subsidiaries;

- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;

- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1.0 million in any year; and

- a change of control, generally defined as the first date on which both of the following two conditions occur: (i) a decrease by CEPH and CEPM of their combined ownership of our outstanding membership interests to less than 20%, and (ii) the ownership by any person (other than a wholly-owned subsidiary of Constellation) of more than 35% of our outstanding membership interests.

The reserve-based credit facilities contain 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 the Company and its subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the facilities and we would be in default under the facilities, which could cause all of our existing indebtedness to become immediately due and payable.

Our reserve-based credit facilities mature in October 2010 and, as a result, amounts due under the facilities are scheduled to become a current liability in October 2009. To date, we have not entered into an agreement to refinance or extend the due date on the reserve-based credit facilities. We may not be able to renew or replace the facilities at similar borrowing costs, terms, covenants, restrictions, or borrowing base, or with similar debt issue costs. In addition, we do not believe that our forecasted cash flow will be sufficient to meet the principal payment that would be required on our outstanding debt balance as it comes due on October 31, 2010 unless we are able to successfully refinance our outstanding debt, extend the due date on our current credit facilities or sell assets. Our inability to refinance our outstanding debt would have a material adverse effect on the Company.

At June 30, 2009, we believe that we were in compliance with the debt covenants contained in our credit facilities. As of June 30, 2009, our actual debt to Adjusted EBITDA ratio was 3.1 to 1.0 as compared with a required ratio of not greater than 3.5 to 1.0, our actual ratio of current assets to current liabilities was 1.7 to 1.0 as compared with a required ratio of not less than 1.0 to 1.0, and our actual Adjusted EBITDA to cash interest expense ratio was 12.5 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If CEP is unable to remain in compliance with the debt covenants associated with its reserve-based credit facilities or maintain the required ratios discussed above, CEP could request waivers from the lenders in its bank group. Although the lenders may not provide a waiver, CEP may take additional steps in the event of not meeting the required ratios or in the event of a reduction in the combined borrowing base below its current level of $225.0 million at the future redetermination by the lenders. If it becomes necessary to pay debt down beyond operating cash flows, CEP could further reduce capital expenditures, continue to suspend quarterly distributions to unitholders, sell oil and natural gas properties or inventories, liquidate in-the-money derivative positions, reduce operating and administrative costs, or take additional steps to increase liquidity. To the extent that CEP does not enter into an agreement to refinance or extend the due date on the reserve-based credit facilities, the outstanding debt balance at October 31, 2009, will become a current liability.

We enter into hedging arrangements to reduce the impact of changes in the LIBOR interest rate on our interest payments for our reserve-based credit facilities. These positions are outlined on page 46.

Management Incentive Interests

CEPM holds management incentive interests in us that represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our limited liability company agreement) has been achieved and certain other tests have been met. Based on our distribution level, beginning in the fourth quarter 2007, we commenced a management incentive interest vesting period. A cash reserve of $0.7 million was established to fund future distributions on the management incentive interests. In February 2009, the Company reduced its quarterly distribution rate to $0.13 per unit for the fourth quarter of 2008. This decrease in the distribution rate terminated the initial management incentive interest vesting period. After the February 13, 2009 distribution was paid, the reserve of $0.7 million was reduced to zero.

Cash Flow from Operations

Our net cash flow provided by operating activities for the six months ended June 30, 2009 was $29.6 million, compared to net cash flow provided by operating activities of $32.3 million for the same period in 2008. This level of operating cash flow was primarily attributable to higher sales of oil and natural gas as a result of our acquisition in the Woodford Shale and increased production volumes as a result of our drilling programs in the Cherokee Basin. The increase in cash flow due to higher production volumes was offset by the impact of significantly lower market prices for natural gas on our unhedged production volumes. For 2009, our operating cash flows were increased by $30.8 million related to cash hedge settlements for our natural gas commodity and interest rate derivatives. Our change in working capital from December 2008 to June 2009 was impacted by lower accounts receivable of $3.3 million, lower royalties payable of $1.6 million, lower accounts payable of $1.1 million and lower affiliate payables and accrued liabilities of $0.6 million. Our receivables balance decreased due to increased collections and lower current period prices for our current estimated natural gas sales prices in all three of our areas. The royalties payable, which represents the amount of monies owed to the royalty owners in our properties for the monthly oil and natural gas sales, decreased due to lower market prices for oil and natural gas. The increase in prepaid expenses of $0.2 million primarily resulted from the timing of the payment for insurance expenses.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through our development programs or completing acquisitions, as well as the market prices of oil and natural gas and our hedging program. For additional information on our business plan, refer to Outlook on page 43.

We enter into hedging arrangements to reduce the impact of natural gas price volatility on our operations. By removing the price volatility from a significant portion of our natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to recoup higher severance taxes, which are usually based on market prices for 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 recoup these higher costs. Increases in the market prices for natural gas may also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender in our reserve-based credit facilities. We do not post collateral under any of these agreements as they are secured under our reserve-based credit facilities.

The following tables summarize, for the periods indicated, our derivatives currently in place through December 31, 2013. All of these derivatives are accounted for as mark-to-market activities.

39

Table of Contents

MTM Fixed Price Swaps NYMEX

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2009					3,090,000	$ 8.46	2,960,000	$ 8.37	6,050,000	$ 8.42
2010	2,950,000	$ 8.31	2,875,000	$ 8.23	2,670,000	$ 8.13	2,700,000	$ 8.15	11,195,000	$ 8.21
2011	2,400,000	$ 8.56	2,425,000	$ 8.56	2,220,000	$ 8.46	2,220,000	$ 8.46	9,265,000	$ 8.51
2012	2,227,500	$ 8.34	2,227,500	$ 8.34	2,250,000	$ 8.34	2,250,000	$ 8.34	8,955,000	$ 8.34
2013	450,000	$ 9.16	455,000	$ 9.16	460,000	$ 9.16	460,000	$ 9.16	1,825,000	$ 9.16
									37,290,000	

MTM Fixed Price Swaps CenterPoint Energy Gas Transmission (East)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2009					230,000	$ 8.11	230,000	$ 8.11	460,000	$ 8.11
2010	180,000	$ 7.91	180,000	$ 7.91	180,000	$ 7.91	180,000	$ 7.91	720,000	$ 7.91
2011	180,000	$ 7.93	180,000	$ 7.93	180,000	$ 7.93	180,000	$ 7.93	720,000	$ 7.93
									1,900,000	

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

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2009					2,137,750	$ 1.01	2,041,000	$ 1.01	4,178,750	$ 1.01
2010	1,572,000	$ 0.96	1,579,500	$ 0.96	1,389,000	$ 0.96	1,290,000	$ 0.96	5,830,500	$ 0.96
2011	1,335,000	$ 0.77	1,347,500	$ 0.77	1,130,000	$ 0.77	1,130,000	$ 0.77	4,942,500	$ 0.77
2012	1,150,000	$ 0.65	1,150,000	$ 0.65	1,160,000	$ 0.65	1,160,000	$ 0.65	4,620,000	$ 0.65
									19,571,750	

Put Options NYMEX

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2009					120,000	$ 7.50	40,000	$ 7.50	160,000	$ 7.50

160,000

In July 2009, we entered to these additional derivative positions. All of these derivatives will be accounted for as mark-to-market activities.

Table of Contents

MTM Fixed Price Swaps NYMEX

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2013	1,575,000	$ 6.81	1,592,500	$ 6.81	1,610,000	$ 6.81	1,610,000	$ 6.81	6,387,500	$ 6.81
2014	1,575,000	$ 7.03	1,592,500	$ 7.03	1,610,000	$ 7.03	1,610,000	$ 7.03	6,387,500	$ 7.03
									12,775,000	

Investing Activities Acquisitions and Capital Expenditures

Cash used in investing activities was $20.6 million for the six months ended June 30, 2009, compared to $69.1 million for the same period in 2008. Our cash capital expenditures were $20.8 million in 2009, which primarily related to drilling and development of oil and natural gas properties in the Cherokee Basin. Through the second quarter of 2009, we drilled and completed 60 net wells and 17 net recompletions in the Cherokee Basin. We have also prepared 10 drilling locations in the Black Warrior Basin.

Our capital expenditures were $69.8 million for the six months ended June 30, 2008, which primarily related to $19.4 million for drilling and development of oil and natural gas properties and $52.4 million for the CoLa Acquisition offset by $2.0 million in post-closing adjustments related to our 2007 acquisitions in the Cherokee Basin. These post-closing adjustments were primarily related to the receipt of revenues between the effective date of the transaction and the closing date and the receipt of $0.8 million in funds related to the Amvest Acquisition. We received another $0.3 million in funds related to the Amvest Acquisition in July 2008. Through the second quarter of 2008, we drilled and completed 15 net wells in the Black Warrior Basin and 35 net wells and 18 net recompletions in the Cherokee Basin.

In our 2009 business plan, we expected that our total capital budget would be between $28.0 million and $33.0 million for the twelve months ending December 31, 2009. This capital budget primarily consists of capital for drilling and also includes amounts for infrastructure projects, equipment, and inventory. The 2009 budget was set at a maintenance capital level and has been reduced from our 2008 spending level of approximately $47.9 million. For 2009, we now expect to only spend between $23.0 million and $25.0 million of our total 2009 budget. Substantially all of this spending will occur in the Cherokee Basin. We will continue to monitor the level of oil and natural gas prices, our liquidity position, our debt level, the results of future borrowing base redeterminations under our credit facilities, and drilling costs when determining the amount of capital expenditures to make to support our business. To the extent that commodity prices do not significantly increase or drilling costs decrease further, we would expect to continue to limit our level of capital expenditures. As of June 30, 2009, we have approximately $3.8 million in accrued capital expenditures and 1 remaining net well in the process of being drilled and completed in the Cherokee Basin.

We do not currently expect to drill any further wells or make any acquisitions in 2009. However, the amount and timing of our capital expenditures is largely discretionary and within our control. We routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry and economic conditions, our debt levels, availability of funds under our reserve-based credit facilities, and internally generated cash flow. Our future cash flows are subject to a number of variables, including the level of natural gas production and prices that we receive for our production. There can be no assurance that our operations and other available capital resources will provide cash in sufficient amounts to provide for future levels of capital expenditures to maintain our current production rates.

Financing Activities

Our net cash provided by financing activities was $1.5 million for the six months ended June 30, 2009, compared to $35.8 million provided by financing activities for the same period in 2008. In 2009, we borrowed a net of $7.5 million to finance capital expenditures and for working capital needs. We also paid distributions of $5.8 million to our common and Class A unitholders in 2009. We have suspended $2.0 million in quarterly distributions on the Class D interests associated with the periods ended June 30, 2009, March 31, 2009, December 31, 2008, September 30, 2008, June 30, 2008, and March 31, 2008. We expect that these quarterly distributions on the Class D interests, and all future quarterly distributions on the Class D interests, will remain suspended until the litigation surrounding the Torch NPI is finally resolved and such distributions are permitted under our credit and limited liability company agreements. For the six months ended June 30, 2009, our distributions to unitholders have been less than our distributable cash flow such that our distribution coverage ratio is greater than 1.0. This coverage ratio compares our distribution rate to our distributable cash flow. Our distributable cash flow reflects Adjusted EBITDA reduced by estimated maintenance capital expenditures and cash interest expense. Our maintenance capital is the amount of capital spending required to maintain our production rates, reserves, and asset base. We have suspended our quarterly distributions to unitholders for the quarter ended June 30, 2009, to remain in compliance with the

Table of Contents

covenants associated with our credit facilities. Assuming that the quarterly distribution rate would have remained at $0.13 per unit for the second, third, and fourth quarters of 2009, this suspension of the quarterly distribution would provide approximately $8.7 million in cash flow that could be used to reduce our outstanding debt balances under our reserve-based credit facilities.

Our net cash provided by financing activities was $35.8 million for the six months ended June 30, 2008. In 2008, we borrowed a total of $63.0 million to fund the CoLa Acquisition, to fund debt issue costs, to finance capital expenditures, and for working capital needs. We also paid distributions of $25.5 million to our common and Class A unitholders and on the Class D interests in 2008, incurred $1.4 million in debt issuance costs and incurred $0.3 million in costs associated with our shelf registration statement.

Contractual Obligations

At June 30, 2009, we had the following contractual obligations or commercial commitments:

	Payments Due By Year[1][2]						
	2009	2010	2011	2012	2013	Thereafter	Total
				(In 000s)			
Management Services Agreement [3]	$ 488	$	$	$	$	$	$ 488
Reserve-Based Credit Facilities		220,000					220,000
Support Services Agreement	642						642
Purchase Obligation							
Total	$ 1,130	$ 220,000	$	$	$	$	$ 221,130

(1) This table does not include any liability associated with derivatives.
(2) This table does not include interest as interest rates are variable. The average interest rate on our outstanding debt was approximately 4.9% at June 30, 2009.
(3) The maximum annual amount for charges under the management services agreement approved by the conflicts committee of our board of managers in February 2009 is $1.7 million.

At June 30, 2009, our asset retirement obligation was approximately $7.0 million.

Off-Balance Sheet Arrangements

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

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor the recent adverse developments in the global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through August 10, 2009, we have not suffered any losses with our counterparties as a result of nonperformance in the current economic and credit crisis.

Certain key counterparty relationships are described below:

CCG

Until March 31, 2009, Constellation Energy Commodities Group, Inc. (CCG) purchased a portion of our natural gas production in Oklahoma and Kansas. As of August 10, 2009, we have no receivables from CCG.

Macquarie Cook Energy LLC

Macquarie Cook Energy LLC (Macquarie Cook), a subsidiary of Sydney, Australia-based Macquarie Group, Ltd. (MQG) purchases the majority of our natural gas production in the Cherokee Basin for May 2009 through October 2009. We have received a guarantee from Macquarie Bank Limited for up to $8 million in purchases through December 31, 2011. As of August 10, 2009, we have no past due receivables from Macquarie Cook.

42

J.P. Morgan Ventures Energy Corporation

J.P. Morgan Ventures Energy Corporation purchases the majority of our natural gas production in Alabama. The payment for the purchases is guaranteed by JP Morgan Chase & Company though October 2009. As of August 10, 2009, we have no past due receivables from J.P. Morgan Ventures Energy Corporation.

Derivative Counterparties

As of August 10, 2009, all of our derivatives are with BNP Paribas, The Royal Bank of Scotland, Societe Generale, Calyon and Bank of Nova Scotia. These banks are lenders who participate in our reserve-based credit facilities. All of our derivatives are collateralized by the assets securing our reserve-based credit facilities. As of August 10, 2009, each of these financial institutions has an investment grade credit rating.

Reserve-Based Credit Facilities

As of August 10, 2009, the banks and their percentage commitments in our two credit facilities are: The Royal Bank of Scotland (23.32%), BNP Paribas (22.55%), Wachovia Bank, N.A. (14.55%), Bank of Nova Scotia (17.00%), Calyon (15.05%), and Societe Generale (7.53%). As of August 10, 2009, each of these financial institutions has an investment grade credit rating.

Outlook

During the remainder of 2009, we expect that our business will continue to be affected by the factors described in Part I, Item 1A. Risk Factors of our Annual Report on Form 10-K for December 31, 2008 that was filed on February 27, 2009, as well as the following key industry and economic trends. Our expectations are 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 2009 Expected Results

Our 2009 business plan and forecast has been focused on maintaining net production levels and promoting financial flexibility by enhancing our liquidity position. This plan was prepared in conjunction with the ongoing strategic review undertaken with Tudor, Pickering, Holt & Co. Securities, Inc., our strategic advisor, and has been approved by our Board of Managers. Our goal is to sustain the company through the current business cycle and position our operations for success over the long-term. We expect our full year 2009 results to be impacted by significantly lower natural gas prices in our operating areas, the limited ability to access our reserve-based credit facilities, the economic recession and uncertainty related to our relationship with Constellation.

We currently anticipate:

- Our production to be between 17.0 Bcfe and 18.5 Bcfe depending on the level and timing of our capital spending in 2009. Based on the mix of wells drilled through June 2009 and our capital spending plan for the remainder of 2009, we now anticipate that our full year production will be at the low end of this range.

- Our operating expenses are expected to be in the range between $57.5 million to $63.5 million.

- Our total capital expenditures under our approved 2009 business plan were expected to be between $28.0 million and $33.0 million, which assumed a decline rate of 13 to 15 percent and a dollar per flowing Mcfe range of $4,400 to $4,600. We now expect our total capital expenditures for 2009 to be between $23.0 million and $25.0 million. For the remainder of 2009, we expect to drill and complete only 1 additional net well in the Cherokee Basin.

Based upon our current business plan, we expect to generate operating cash flows in excess of our remaining 2009 maintenance capital expenditures and working capital needs. We currently intend to retain any available surplus cash as we execute our operating plan during the remainder of 2009. This excess cash flow may be used to reduce our debt levels. We expect to renew or replace our existing credit facilities prior to their maturity on October 31, 2010.

Our quarterly distribution rate will remain suspended until after our outstanding debt balance is less than 90% of our borrowing base as determined by our lenders. We are subject to additional future borrowing base redeterminations and cannot forecast at what level our lenders will set our future borrowing base. However, after our outstanding debt balance is less than 90% of our borrowing base, we will evaluate the resumption of our quarterly distribution to unitholders. We anticipate that our distribution will remain suspended until our debt levels are reduced and we resume capital spending at maintenance levels. Any future quarterly distributions must be approved by our Board of Managers.

Update on Strategic Alternatives

We continue to work with our strategic advisor to analyze various alternatives to enhance unitholder value. At this time, our Board of Managers has determined to continue to focus on internal opportunities and to run our business by transitioning the remaining services provided under the management services agreement with CEPM to CEP prior to December 15, 2009. We do not intend to disclose developments with respect to this review unless and until the Board of Managers has approved a course of action.

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 that are believed to be reasonable under the circumstances, the results of which 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, 2009, 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, 2008. The policies disclosed included the accounting for natural gas properties, natural gas reserve quantities, net profits interest, 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

In May 2009, the Financial Accounting Standards Board issued SFAS 165, *Subsequent Event* (SFAS 165). SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist in the auditing standards. The standard, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. CEP performs an evaluation of subsequent events until the filing date of its document with the SEC so the adoption of SFAS 165 had no impact on our financial statements.

In June 2008, the Financial Accounting Standards Board issued a FASB Staff Position (FSP) on EITF Issue No. 03-06-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. This FSP addresses whether instruments granted in unit-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per unit under the two-class method described in SFAS 128, *Earnings Per Share*. It affects entities that accrue or pay nonforfeitable cash distributions on unit-based payment awards during the awards service period. FSP EITF 03-06-1 is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years and will require a retrospective adjustment to all prior period earnings per unit calculations. CEP adopted FSP EITF 03-06-1 on January 1, 2009, and began including all unvested LTIP restricted common units that earn distributions in earnings per unit calculations for all periods presented.

In March 2008, the FASB issued SFAS 161, *Disclosures About Derivative Instruments and Hedging Activities*. SFAS 161 is effective beginning January 1, 2009 and requires entities to provide expanded disclosures about derivative instruments and hedging activities including (1) the ways in which an entity uses derivatives, (2) the accounting for derivatives and hedging activities, and (3) the impact that derivatives have (or could have) on an entity s financial position, financial performance, and cash flows. SFAS 161 requires expanded disclosures and does not change the accounting for derivatives. The adoption of this standard did not have an impact on our financial statements.

In March 2008, the Emerging Issues Task Force reached a consensus on Issue 07-4, or EITF 07-4, Application of the Two-Class Method under FASB Statement 128, *Earnings Per Share*, to Master Limited Partnerships. EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. This Issue is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted, and the guidance in this Issue is to be applied retrospectively for all financial statements presented. The adoption of this Issue did not have a material impact on our financial statements.

44

Table of Contents

New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2009, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us.

In June 2009, the Financial Accounting Standards Board released the final version of its new Accounting Standards Codification (the Codification) as the single authoritative source for U.S. GAAP. The Codification replaces all previous U.S. GAAP accounting standards as described in SFAS 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* (SFAS 168). While not intended to change U.S. GAAP, the Codification significantly changes the way in which the accounting literature is organized. It is structured by accounting topic to help accountants and auditors more quickly identify the guidance that applies to a specific accounting issue. However, because the Codification completely replaces existing standards, it will affect the way U.S. GAAP is referenced by companies in their financial statements and accounting policies. The Codification is effective for financial statements that cover interim and annual periods ending after September 15, 2009. We are currently evaluating the potential impact of adopting the Codification.

On December 31, 2008, the Securities and Exchange Commission (SEC) issued the final rule, Modernization of Oil and Gas Reporting (Final Rule). The Final Rule adopts revisions to the SEC s oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and technological advances. Revised requirements in the Final Rule include, but are not limited to:

- Oil and gas reserves must be reported using a 12-month average of the closing prices on the first day of each of such months, rather than a single day year-end price;

- Companies will be allowed to report, on a voluntary basis, probable and possible reserves, previously prohibited by SEC rules; and

- Easing the standard for the inclusion of proved undeveloped reserves (PUDs) and requiring disclosure of information indicating any progress toward the development of PUDs.

We are currently evaluating the potential impact of adopting the Final Rule. The SEC is discussing the Final Rule with the FASB and IASB staffs to align accounting standards with the Final Rule. These discussions may delay the required compliance date. Absent any change in such date, we will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ended December 31, 2009. Voluntary early compliance is not permitted.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Global Financial and Energy Markets

During 2008 and 2009, there has been unprecedented volatility in global financial and energy markets. The failures of financial institutions have effectively restricted current liquidity within global financial markets. Despite world-wide governmental efforts to provide liquidity to the financial sector, capital and credit markets currently remain constrained. We expect that our ability to issue debt and equity will be limited over the next year should capital markets remain in crisis and that the cost of capital may increase during this time. We also may have difficulty in accessing credit should we have the need to. Additionally, the market prices for oil and natural gas have significantly declined since June 2008. This decline may result in a further decrease in our total $225.0 million borrowing base under our reserve-based credit facilities at the next redetermination prior to the facilities maturing in October 2010. The equity valuations for energy-related companies and E&P master limited partnerships in particular, have fallen dramatically. In response to the credit crisis and the decline in the market prices for oil and natural gas, many energy companies have reduced their planned capital expenditures or have shut-in production. In response, we have suspended our cash distribution and lowered our capital expenditure budget for 2009 as compared to 2008. We do expect that if market prices for oil and natural gas remain depressed, our future cash flows from operations will be reduced for our unhedged production. We will continue to monitor the financial and energy markets to determine if we should revise the timing and scope of our future drilling programs, financing activities, acquisition activities, or resume cash distributions to our unitholders.

Table of Contents

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. Realized pricing is primarily driven by the Inside FERC prices for Southern Natural Gas Company (Louisiana) with respect to our properties in the Black Warrior Basin and the Inside FERC prices for CenterPoint Energy Gas Transmission (East), Natural Gas Pipeline Company of America (Midcontinent), the CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipeline (Texas, Oklahoma) and Southern Star Central Gas Pipeline (Texas, Oklahoma, Kansas) with respect to our properties in the Cherokee Basin, and the Inside FERC price for the CenterPoint Energy Gas Transmission (East) for our properties in the Woodford Shale, and the spot market prices applicable to all of our natural gas production. Historically, pricing for natural gas production has been volatile and unpredictable and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control, including weather, economic conditions, and the total supply of oil and natural gas for sale in the market.

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

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**(Decrease)**	**Fair Value**	**Increase**
			(in 000 s)		
Impact of changes in commodity prices on derivative commodity instruments at June 30, 2009	$ 67,433	$ 51,828	$ (15,605)	$ 96,046	$ 28,613

Interest Rate Risk

At June 30, 2009, we had debt outstanding of $220.0 million. This entire amount incurred interest at a rate of a one-month LIBOR rate plus an applicable margin of 1.25% and 2.00% based on utilization. At June 30, 2009, the one-month LIBOR rate was 0.309% and the three-month LIBOR rate was 0.595%, and our applicable margin was 2.00%. At June 30, 2009, the ABR rate was 3.25%, and our applicable margin was 1.00%. We had no debt outstanding at the three-month LIBOR rate or at the ABR rate. At June 30, 2009, the carrying value and fair value of our debt is $220.0 million.

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

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**Increase**	**Fair Value**	**(Decrease)**
			(in 000 s)		
Impact of changes in LIBOR on derivative interest rate instruments at June 30, 2009	$ (6,725)	$ (6,399)	$ 326	$ (7,051)	$ (326)

We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for our debt. At June 30, 2009, we have the following outstanding interest rate swaps that fix our LIBOR rate:

Maturity Date	Total Debt Hedged (in 000 s)	LIBOR Fixed Rate
February 20, 2010	$ 16,500	4.74%

August 20, 2010	$	11,000	4.58%
August 21, 2010	$	28,500	2.74%
September 20, 2010	$	45,000	4.96%
September 21, 2010	$	11,000	2.66%
October 19, 2010	$	29,500	4.81%
October 22, 2010	$	7,500	4.56%
October 22, 2010	$	19,000	2.91%

Table of Contents

Item 4. Controls and Procedures

A control system, no matter how well conceived 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 the end of the fiscal quarter covered by this quarterly report (the Evaluation Date). Based on such evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that, as of the Evaluation Date, CEP s disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. During the six months ended June 30, 2009, 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

Termination of the Trust and Related Litigation

On January 29, 2008, the unitholders of the Torch Energy Royalty Trust voted to terminate the Trust and authorized the Trustee to wind up, liquidate, and distribute the assets held by the Trust under the terms of the trust agreement. As discussed beginning on page 21 in Note 11, we are involved in litigation related to the calculation of the NPI held by the Trust in the Robinson s Bend Field in Alabama.

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. 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

Except as identified below, 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 December 31, 2008 that was filed on February 27, 2009. An investment in our common units involves various risks. When considering an investment in us, careful consideration should be given to the risk factors described in our 2008 Form 10-K. These risks and uncertainties are not the only ones facing us and there may be additional matters that are not known to us or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition or future results and, thus, the value of an investment in us.

Tax Risks to Unitholders

Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

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

On May 15, 2009, we paid a cash distribution of $0.13 on each common unit (or Class B) and Class A unit. If we generate taxable income for the 2009 tax year and do not resume cash distributions in 2009, our unitholders who received that cash distribution and any unitholders who purchase or purchased common units after the record date for such distribution may not receive cash distributions from us during 2009 sufficient to pay the actual tax liability that results from their share of such 2009 taxable income.

Risks Related to Our Distribution to Unitholders

We may not have sufficient available cash from operations to resume our quarterly cash distributions to unitholders following the reduction of outstanding debt balances and the establishment of cash reserves and the payment of fees and expenses.

Our quarterly distribution rate has been suspended in order to remain in compliance with the covenants associated with our reserve-based credit facilities. Before we can resume our quarterly cash distributions, we must reduce our outstanding debt balances to less than 90% of our borrowing base as determined by our lenders. We are subject to additional future borrowing base redeterminations before our reserve-based credit facilities mature in October 2010 and cannot forecast at what level our lenders will set our future combined borrowing base. If our lenders further reduce our combined borrowing base because of any of the numerous factors generally described in this caption Risk Factors, our outstanding debt balances may remain at more than 90% of our borrowing base as determined by our lenders and we may be unable to resume our quarterly cash distributions or may again have to suspend our quarterly cash distributions. If we do not achieve our expected operational results and do not reduce our outstanding debt levels, we may not be able to resume quarterly cash distributions, in which event the market price of our common units may decline substantially.

In addition, we may not have sufficient available cash or future cash flow from operations each quarter to pay cash distributions to our unitholders following establishment of cash reserves by our board of managers for the proper conduct of our business and the payment of fees and expenses. The amount of available cash from which we may pay distributions is defined in both our reserve-based credit facilities and our limited liability company agreement. The amount of available cash we distribute is subject to the definition of operating surplus in our limited liability company agreement. Ultimately, the amount of available cash that we may distribute to our unitholders principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on numerous factors generally described in this caption Risk Factors, including, among other things: the amount of oil and natural gas we produce; the demand for and the price at which we are able to sell our oil and natural gas production; the results of our hedging activity; the level of our operating costs, including reimbursements to CEPM under the management services agreement; the costs we incur to acquire E&P properties; whether we are able to continue our development activities at economically attractive costs; the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; the amount of working capital required to operate our business; and the level of our maintenance capital expenditures.

The amount of available cash that we will have to distribute to our unitholders also depends on other factors, some of which are beyond our control, including: the borrowing bases under our reserve-based credit facilities; our ability to make working capital borrowings under our reserve-based credit facilities to pay distributions; our debt service requirements and covenants and restrictions on distributions contained in our reserve-based credit facilities; fluctuations in our working capital needs; the timing and collectability of receivables; prevailing economic conditions; the amount of our estimated maintenance capital expenditures; and the amount of cash reserves established by our board of managers for the proper conduct of our business, including the maintenance of our asset base and the payment of future cash distributions on our Class A and common units, any management incentive interests and Class D interests. As a result of these factors, we may not have sufficient available cash to resume our quarterly distributions. Even if we were able to resume a quarterly cash distribution because we have reduced our outstanding debt balances to a level that complies with our debt covenants, the amount of available cash that we could distribute from our operating surplus in any quarter to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than the quarterly distribution amount of $0.13 per unit that we paid for the first quarter 2009. If we do not have sufficient available cash or future cash flow from operations to resume quarterly cash distributions, the market price of our common units may decline substantially.

Table of Contents

Risks Related to Our Business

Potential regulatory actions could increase our operating or capital costs and delay our operations or otherwise alter the way we conduct our business. Exploration and development activities and the production and sale of oil and natural gas are subject to extensive federal, state, local and tribal regulations. Changes to existing regulations or new regulations may unfavorably impact us, our suppliers or our customers. In the United States, legislation that directly impacts the oil and gas industry has been recently proposed covering areas such as emission reporting and reductions, hydraulic fracturing of wells, the repeal of certain oil and natural gas tax incentives and tax deductions, and the regulation of commodity derivatives. These and other potential regulations could increase our costs, reduce our liquidity, impact our ability to hedge our future oil and natural gas sales, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows.

Forward-Looking Statements

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

- the volatility of realized oil and natural gas prices;
- the conditions of the capital markets, inflation, interest rates, availability of credit facilities to support business requirements, liquidity, and general economic conditions;
- the discovery, estimation, development and replacement of oil and natural gas reserves;
- our business, financial, and operational strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- the resumption or amount of our cash distribution;
- the impact from any termination of the Robinson s Bend sharing arrangement;
- our hedging program and our derivative positions;
- our production volumes;

- our lease operating expenses, general and administrative costs and finding and development costs;
- the availability of drilling and production equipment, labor and other services;
- our future operating results;
- our prospect development and property acquisitions;
- the marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of the current global credit crisis and economic recession;
- the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, tornados, earthquakes, snow and ice storms and other catastrophic events and natural disasters;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas producing countries;
- support from our sponsor or a change in our sponsor; and
- our strategic plans, objectives, expectations, forecasts, budgets, estimates and intentions for future operations.

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 1. Business; Item 1A. Risk Factors; Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and other items within this Quarterly Report on Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as may, could, should, expect, plan, project, intend, anticipate, estimate, predict, potential, pursue, target, continue, the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond

Table of Contents

our control. In addition, management s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Quarterly Report on Form 10-Q are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors listed in the Risk Factors section and elsewhere in this Quarterly Report on Form 10-Q. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

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:

Consolidated Statements of Operations and Comprehensive Income/(Loss) Constellation Energy Partners LLC for the three months ended June 30, 2009 and June 30, 2008 and for the six months ended June 30, 2009 and June 30, 2008

Consolidated Balance Sheets Constellation Energy Partners LLC at June 30, 2009 and December 31, 2008

Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the six months ended June 30, 2009 and June 30, 2008

Consolidated Statements of Changes in Members Equity and Comprehensive Income Constellation Energy Partners LLC for the six months ended June 30, 2009

Notes to Consolidated Financial Statements

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended (incorporated herein by reference to Exhibit 3.1 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 12, 2007)
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
3.3	Amendment No. 1 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007)
3.4	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC dated July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
3.5	Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC dated September 21, 2007 (incorporated by reference to Exhibit 3.5 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
3.6	Amendment No. 4 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on December 28, 2007).
10.1	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Stephen R. Brunner (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
10.2	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Charles C. Ward (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
10.3	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Lisa J. Mellencamp (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
10.4	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Michael B. Hiney (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
10.5	Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Stephen R. Brunner (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
10.6	Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Charles C. Ward (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
10.7	Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Lisa J. Mellencamp (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
10.8	Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Michael B. Hiney (incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
10.9	Form of Grant Agreement for Executive Officers (incorporated by reference to Exhibit 10.9 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).

10.10	Form of Grant Agreement for Independent Managers (incorporated by reference to Exhibit 10.10 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).
*31.1.	Certification of Chief Executive Officer, Chief Operating Officer and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2.	Certification of Chief Financial Officer and Treasurer 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 Chief Financial Officer and Treasurer 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.

* Filed herewith

Table of Contents

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 10, 2009	By /s/ MICHAEL B. HINEY Michael B. Hiney Chief Accounting Officer and Controller

52