Constellation Energy Partners LLC
Form 10-Q
August 06, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2010

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.)**
1801 Main Street, Suite 1300 Houston, Texas	**77002**
(Address of Principal Executive Offices)	**(Zip Code)**

Telephone Number: (832) 308-3700

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

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

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

Large accelerated filer ¨	Accelerated filer ¨
Non-accelerated filer x (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 6, 2010: 23,978,465 units.

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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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In 000 s except unit data)			
Revenues				
Oil and gas sales	$ 27,078	$ 30,698	$ 56,315	$ 63,560
Gain / (Loss) from mark-to-market activities (see Note 4)	(4,549)	(12,134)	30,732	7,197
Total revenues	22,529	18,564	87,047	70,757
Expenses:				
Operating expenses:				
Lease operating expenses	7,729	8,289	15,692	17,074
Cost of sales	585	612	1,357	1,444
Production taxes	677	560	1,802	1,530
General and administrative expenses	4,188	4,208	9,250	9,441
Exploration costs	224	103	447	206
(Gain) / Loss on sale of assets	(5)	(3)	(13)	14
Depreciation, depletion, and amortization	26,733	18,195	53,981	32,629
Accretion expense	205	56	412	157
Total operating expenses	40,336	32,020	82,928	62,495
Other expenses (income)				
Interest expense	3,275	2,723	6,814	5,222
Interest expense-(Gain)/Loss from mark-to-market activities (see Note 4)	113	555	630	899
Interest (income)	(1)		(1)	(2)
Other expense (income)	(102)	10	(290)	(47)
Total other expenses	3,285	3,288	7,153	6,072
Total expenses	43,621	35,308	90,081	68,567
Net income (Loss)	$ (21,092)	$ (16,744)	$ (3,034)	$ 2,190
Other comprehensive (Loss)	(4,264)	(11,354)	(9,550)	(3,641)
Comprehensive (Loss)	$ (25,356)	$ (28,098)	$ (12,584)	$ (1,451)
Earnings (loss) per unit (see Note 2)				
Earnings (loss) per unit Basic	$ (0.87)	$ (0.74)	$ (0.12)	$ 0.10
Units outstanding Basic	24,538,151	22,500,701	24,271,742	22,443,699
Earnings (loss) per unit Diluted	$ (0.87)	$ (0.74)	$ (0.12)	$ 0.10
Units outstanding Diluted	24,538,151	22,500,701	24,271,742	22,443,699

Distributions declared and paid per unit	$	0. 00	$	0. 13	$	0.00	$	0.26

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

(Unaudited)

	June 30, 2010	December 31, 2009
	(In 000 s)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 12,697	$ 11,337
Accounts receivable	7,027	8,379
Prepaid expenses	1,324	1,298
Risk management assets (see Note 4)	32,960	24,251
Total current assets	54,008	45,265
Oil and natural gas properties (See Note 6)		
Oil and natural gas properties, equipment and facilities	799,566	794,520
Material and supplies	3,960	4,312
Less accumulated depreciation, depletion and amortization	(239,623)	(186,207)
Net oil and natural gas properties	563,903	612,625
Other assets		
Debt issue costs (net of accumulated amortization of $3,893 at June 30, 2010 and $2,924 at December 31, 2009)	4,644	5,590
Risk management assets (see Note 4)	45,551	33,916
Other non-current assets	10,552	10,921
Total assets	$ 678,658	$ 708,317
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 1,308	$ 1,102
Payable to affiliate	19	201
Accrued liabilities	8,731	10,033
Environmental liabilities	193	193
Royalty payable	3,026	4,747
Risk management liabilities (see Note 4)		208
Total current liabilities	13,277	16,484
Other liabilities		
Asset retirement obligation	12,532	12,129
Debt	180,000	195,000
Total other liabilities	192,532	207,129
Total liabilities	205,809	223,613
Commitments and contingencies (See Note 8)		
Class D Interests	6,667	6,667
Members equity		
	8,947	8,993

Class A units, 490,515 and 476,950 shares authorized, issued and outstanding at June 30, 2010 and December 31, 2009, respectively		
Class B units, 24,298,763 and 24,298,763 shares authorized at June 30, 2010 and December 31, 2009, respectively, and 24,035,241 and 23,376,136 issued and outstanding at June 30, 2010 and December 31, 2009, respectively	438,418	440,677
Accumulated other comprehensive income	18,817	28,367
Total members equity	466,182	478,037
Total liabilities and members equity	$ 678,658	$ 708,317

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Six months ended June 30, 2010	2009
	(In 000 s)	
Cash flows from operating activities:		
Net income (loss)	$ (3,034)	$ 2,190
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	53,981	32,629
Amortization of debt issuance costs	969	543
Accretion of plugging and abandonment liability	412	157
Equity earnings (losses) in affiliate	(292)	(47)
(Gain) Loss from disposition of property and equipment	(13)	14
Hedge ineffectiveness		267
(Gain) Loss from mark-to-market activities	(30,102)	(6,298)
Unit-based compensation programs	1,030	152
Changes in Assets and Liabilities:		
Change in net risk management assets and liabilities		290
(Increase) decrease in accounts receivable	1,352	3,332
(Increase) decrease in prepaid expenses	(24)	(184)
(Increase) decrease in other assets	(2)	2
Increase (decrease) in accounts payable	206	(1,077)
Increase (decrease) in payable to affiliate	(182)	(612)
Increase (decrease) in accrued liabilities	(3,246)	(105)
Increase (decrease) in royalty payable	(1,721)	(1,646)
Net cash provided by operating activities	19,334	29,607
Cash flows from investing activities:		
Cash (paid) / received for acquisitions, net of cash acquired	(504)	29
Development of natural gas properties	(2,261)	(20,806)
Proceeds from sale of equipment	29	17
Distributions from equity affiliate	115	160
Net cash used in investing activities	(2,621)	(20,600)
Cash flows from financing activities:		
Members distributions		(5,820)
Proceeds from issuance of debt		34,500
Repayment of debt	(15,000)	(27,000)
Units tendered by employees	(301)	
Equity issue costs	(2)	(4)
Debt issue costs	(50)	(94)
Net cash provided by (used in) financing activities	(15,353)	1,582
Net (decrease) increase in cash	1,360	10,589
Cash and cash equivalents, beginning of period	11,337	6,255

Cash and cash equivalents, end of period	$ 12,697	$ 16,844
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 2,153	$ 825
Cash received during the period for interest	$ 1	$ 2
Cash paid during the period for interest	$ (3,696)	$ (3,915)

See accompanying notes to consolidated financial statements.

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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, 2009	476,950	$ 8,993	23,376,136	$ 440,677	$ 28,367	$ 478,037
Distributions						
Units tendered by employees for tax withholding		(6)		(295)		(301)
Change in fair value of commodity hedges					108	108
Cash settlement of commodity hedges					(10,047)	(10,047)
Cash settlement of interest rate hedges					389	389
Unit-based compensations programs	13,565	21	659,105	1,009		1,030
Net income (loss)		(61)		(2,973)		(3,034)
Balance, June 30, 2010	490,515	$ 8,947	24,035,241	$ 438,418	$ 18,817	$ 466,182

See accompanying notes to consolidated financial statements.

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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, 2010, 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, 2009. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2010 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 , we , us , our or the Company). We completed our initial public offering on November 20, 2006, and trade on the NYSE Arca under the symbol CEP . We are 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, 2010, affiliates of Constellation own all of our Class A units, all of the management incentive interests, approximately 25% of our common units and all of our Class D interests.

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2009.

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, 2010, we had 490,515 Class A units and 24,035,241 Class B units outstanding. Of the Class B units, 1,837,911 units are restricted unvested common units granted and outstanding. See Note 15 for additional information.

The following table presents earnings per common unit amounts:

	Income	Units	Per Unit Amount

	(In 000 s except unit data)		
For the three months ended June 30, 2010			
Basic EPS:			
Income allocable to unitholders	$ (21,092)	24,538,151	$ (0.87)
Effect of dilutive securities:			
Restricted common units Treasury stock method			

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	Income	Units	Per Unit Amount
	(In 000 s except unit data)		
For the three months ended June 30, 2010			
Diluted EPS:			
Income allocable to common unitholders	$ (21,092)	24,538,151	$ (0.87)

	Income	Units	Per Unit Amount
	(In 000 s except unit data)		
For the six months ended June 30, 2010			
Basic EPS:			
Income allocable to unitholders	$ (3,034)	24,271,742	$ (0.12)
Effect of dilutive securities:			
Restricted common units Treasury stock method			
Diluted EPS:			
Income allocable to common unitholders	$ (3,034)	24,271,742	$ (0.12)

	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:			
Restricted common units Treasury stock method			
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:			
Restricted common units Treasury stock method			
Diluted EPS:			
Income allocable to common unitholders	$ 2,190	22,443,699	$ 0.10

3. NEW ACCOUNTING PRONOUNCEMENTS

In January 2010, the FASB issued its final guidance on additional supplemental fair value disclosures. Two new disclosures will be required: (1) a gross presentation of activities (purchases, sales, and settlements) within the Level 3 roll forward reconciliation, which will replace the net presentation format, and (2) detailed disclosures about the transfers between Level 1 and 2 measurements. The guidance also provides several clarifications regarding the level of disaggregation and disclosures about inputs and valuation techniques. The new disclosures are effective for the first quarter 2010 for calendar year-end companies, except for the Level 3 gross activity disclosures, which will be deferred until the first quarter of 2011. The adoption of this guidance did not have a material impact on our financial statements or our disclosures.

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In February 2010, the FASB amended its guidance on subsequent events. SEC filers are now not required to disclose the date through which an entity has evaluated subsequent events. The amended guidance was effective upon issuance. The adoption of this guidance did not have an impact on our financial statements or our disclosures.

New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2010, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. We are currently reviewing the recently issued standards and interpretations but none are expected to have a material impact on our financial statements.

4. DERIVATIVE AND FINANCIAL INSTRUMENTS

Mark-to-Market Activities

We have hedged a portion of our expected natural gas sales from currently producing wells through December 2014. All of our swaps and basis swaps were accounted for as mark-to-market activities as of June 30, 2010.

At June 30, 2010 and December 31 2009, we had debt outstanding of $180.0 million and $195.0 million, respectively, under our reserve-based credit facility. We have 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 $151.5 million of outstanding debt for various maturities extending through October 2012. All of our interest rate swaps are accounted for as mark-to-market activities as of June 30, 2010. Prior to February 2009, they were accounted for as cash flow hedges.

For the six months ended June 30, 2010 and 2009, we recognized mark-to-market gains of approximately $30.7 million and $7.2 million, respectively, in connection with our commodity derivatives. For the six months ended June 30, 2010 and 2009, we recognized mark-to-market losses of approximately $0.6 million and $0.9 million, respectively, in connection with our interest rate derivatives. At June 30, 2010 and December 31, 2009, the fair value of the derivatives accounted for as mark-to-market activities amounted to a net asset of approximately $78.5 million and a net asset of approximately $58.0 million, respectively.

Accumulated Other Comprehensive Income

Prior to the first quarter of 2009, we accounted for certain of our commodity and interest rate derivatives as 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 $18.8 million and an unrecognized gain of approximately $28.4 million at June 30, 2010 and December 31, 2009, respectively. We expect 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	Non-performance Risk	Total AOCI
September 30, 2010	3,731	(54)	3,677
December 31, 2010	3,568	(62)	3,506
March 31, 2011	922	(28)	894
June 30, 2011	2,147	(78)	2,069
September 30, 2011	1,921	(78)	1,843
December 31, 2011	1,456	(65)	1,391
March 31, 2012	718	(22)	696
June 30, 2012	1,928	(66)	1,862
September 30, 2012	1,721	(63)	1,658
December 31, 2012	1,271	(50)	1,221
Total	$ 19,383	$ (566)	$ 18,817

Fair Value Measurements

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

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

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

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

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

The following tables sets forth by level within the fair value hierarchy our assets and liabilities that were measured at fair value on a recurring basis as of June 30, 2010 and December 31, 2009.

	Commodity		Interest rate	Netting and Cash	Total Net Fair
At June 30, 2010	**Level 1**	**Level 2**	**Level 3**	**Collateral***	**Value**
			(In 000 s)		
Risk management assets	$	$ 83,479	$ (4,968)	$	$ 78,511
Risk management liabilities	$	$	$	$	$
Total	$	$ 83,479	$ (4,968)	$	$ 78,511

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

	Commodity		Interest rate	Netting and Cash	Total Net Fair
At December 31, 2009	**Level 1**	**Level 2**	**Level 3**	**Collateral***	**Value**
			(In 000 s)		
Risk management assets	$	$ 62,894	$ (4,727)	$	$ 58,167
Risk management liabilities	$	$ (208)	$	$	$ (208)
Total	$	$ 62,686	$ (4,727)	$	$ 57,959

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

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

We use observable market data or information derived from observable market data in order to determine the fair value amounts presented above. Prior to September 30, 2009, the valuation of our derivatives was performed by Constellation under a management services agreement (see Note 7). In order to determine the fair value amounts presented above, Constellation utilized 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 included 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 facility to provide credit support for our derivative transactions. 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, 2010, the impact of non-performance credit risk on the valuation of our assets from counterparties was $1.6 million, of which $1.0 million was reflected as a decrease to our non-cash mark-to-market gain and $0.6 million was reflected as a reduction to our accumulated other comprehensive income. 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 mark-to-market gain and $0.9 million was reflected as a reduction to our accumulated other comprehensive income.

We use observable market data or information derived from observable market data to measure the fair value of our derivative instruments. Prior to September 30, 2009, in certain instances, Constellation may have utilized internal models to measure the fair value of our derivative instruments. Generally, Constellation used similar models to value similar instruments. Valuation models utilized various inputs which included quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that were not active, other observable inputs for the assets or liabilities, and market-corroborated inputs, which were 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, 2010 (In 000 s)	Six Months Ended June 30, 2010 (In 000 s)
Balance at beginning of period	$ (4,855)	$ (4,727)
Realized and unrealized gain (loss):		
Included in earnings	(1,130)	(2,873)
Included in other comprehensive income		389
Purchases, sales, issuances, and settlements	1,017	2,243
Transfers into and out of Level 3		
Balance as of June 30, 2010	$ (4,968)	$ (4,968)
Change in unrealized gains relating to derivatives still held as of June 30, 2010	$ (1,130)	$ (2,484)

	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 gain (loss):		
Included in earnings	(6,889)	(6,936)
Included in other comprehensive income		(1,311)
Purchases, sales, issuances, and settlements	1,650	1,229
Transfers into and out of Level 3		
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)

Fair Value of Financial Instruments

At June 30, 2010, 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. We believe 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.

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The following fair value disclosures are applicable to our financial statements, as of June 30, 2010 and December 31, 2009:

Derivative Type	Location of Asset / (Liability)	Fair Value of Asset / (Liability) (in 000 s) Three Months Ended June 30, 2010	Year Ended December 31, 2009
Commodity-MTM	Risk management assets	$ 97,333	$ 77,577
Commodity-MTM	Risk management assets	(13,854)	(14,683)
Commodity-MTM	Risk management liabilities		(208)
Interest Rate-MTM	Risk management assets	(4,968)	(4,727)
	Total Derivatives	$ 78,511	$ 57,959

Derivative Type	Location of Gain / (Loss) in Income	Amount of Gain / (Loss) in Income (in 000 s) Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ (4,549)	$ (12,134)
Commodity-MTM	Oil and gas sales	7,088	4,795
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to-market activities	(113)	(555)
Interest Rate-MTM	Interest expense	(1,017)	(1,227)
	Total	$ 1,409	$ (9,121)

Derivative Type	Location of Gain / (Loss) in Income	Amount of Gain / (Loss) in Income (in 000 s) Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ 30,732	$ 7,197
Commodity-MTM	Oil and gas sales	8,986	6,798
Interest Rate-MTM	Interest expense- Gain/(Loss) from mark-to-market activities	(630)	(899)
Interest Rate-MTM	Interest expense	(1,854)	(1,829)
	Total	$ 37,234	$ 11,267

Derivative Type	Location of Gain / (Loss)	Amount of Gain /(Loss) Reclassified from AOCI into Income - Effective		Amount of Gain /(Loss) in Income - Ineffective	
		Three Months Ended June 30,	Three Months Ended June 30,	Three Months Ended June	Three Months Ended June 30,

	for Effective and Ineffective Portion of Derivative in Income	2010	2009	30, 2010	2009
Commodity-MTM	Oil and gas sales	$ 4,319	$	$	$
Commodity-Cash Flow	Oil and gas sales		12,623		
Interest Rate-Cash Flow	Interest expense		(1,239)		
	Total	$ 4,319	$ 11,384	$	$

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Derivative Type	Location of Gain / (Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain /(Loss) Reclassified from AOCI into Income - Effective Six Months Ended June 30, 2010	Amount of Gain /(Loss) Reclassified from AOCI into Income - Effective Six Months Ended June 30, 2009	Amount of Gain /(Loss) in Income - Ineffective Six Months Ended June 30, 2010	Amount of Gain /(Loss) in Income - Ineffective Six Months Ended June 30, 2009
Commodity-MTM	Oil and gas sales	$ 10,047	$	$	$
Commodity-Cash Flow	Oil and gas sales		25,771		267
Interest Rate-Cash Flow	Interest expense	(389)	(1,840)		
	Total	$ 9,658	$ 23,931	$	$ 267

As of June 30, 2010, we have interest rate swaps on $151.5 million of outstanding debt for various maturities extending through October 2012, various commodity swaps for 39,270,000 MMbtu of natural gas production through December 2014, and various basis swaps for 23,071,541 MMbtu of natural gas production in the Cherokee Basin through December 2012.

5. DEBT

Reserve-Based Credit Facility

On November 13, 2009, we entered into an amended and restated $350.0 million reserve-based credit facility with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders. The reserve-based credit facility amends, extends, and consolidates our previous reserve-based credit facilities and matures on November 13, 2012. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The current lenders and their percentage commitments in the reserve-based credit facility are: The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), Wells Fargo Bank, N.A. (14.63%), and Societe Generale (14.63%).

The amount available for borrowing at any one time under the reserve-based credit facility is limited to the borrowing base for our oil and natural gas properties in Alabama, Kansas, and Oklahoma. As of June 30, 2010, our borrowing base was $205.0 million. The borrowing base is redetermined semi-annually, and may be redetermined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, together with, among other things, the oil and natural gas prices prevailing at such time. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Borrowings under the reserve-based credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the reserve-based credit facility, working capital and general limited liability company purposes. The reserve-based credit facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit. As of June 30, 2010, no letters of credit are outstanding.

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

The reserve-based credit facility contains various covenants that limit, among other things, our ability and certain of our subsidiaries ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and make distributions to unitholders.

In addition, we are required to maintain (i) a ratio of Total Net Debt (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents, and cash reserves of the Company)) to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus (minus) the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets,

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(gain) loss on sale of assets, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives, and other similar charges) of not more than 3.75 to 1.0 through September 30, 2010 and 3.50 to 1.0 thereafter; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143 (including the current liabilities in respect of the termination of natural gas and interest rate swaps). All financial covenants are calculated using our consolidated financial information.

The reserve-based credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, guaranties not being valid under the reserve-based credit facility and a change of control. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of June 30, 2010, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to make distributions, and our borrowings outstanding, net of available cash, under our reserve-based credit facility exceeded 90% of the borrowing base.

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

The reserve-based credit facility contains no covenants related to our relationship with Constellation or Constellation s right to appoint all of the Class A managers of our board of managers.

Debt Issue Costs

As of June 30, 2010, our unamortized debt issue costs were approximately $4.6 million. These costs are being amortized over the life of the credit facility through November 2012.

Funds Available for Borrowing

As of June 30, 2010 and December 31, 2009, we had $180.0 million and $195.0 million, respectively, in outstanding debt under our reserve-based credit facility. As of June 30, 2010, we had $25.0 million in remaining borrowing capacity under the reserve-based credit facility.

Compliance with Debt Covenants

At June 30, 2010, we believe that we were in compliance with the financial covenant ratios contained in our reserve-based credit facility. We monitor compliance on an ongoing basis. As of June 30, 2010, our actual Total Net Debt less Available Cash to Adjusted EBITDA ratio was 2.7 to 1.0 as compared with a required ratio of not greater than 3.75 to 1.0, our actual ratio of consolidated current assets to consolidated current liabilities was 3.5 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 8.2 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If we are unable to remain in compliance with the financial covenants associated with our reserve-based credit facility or maintain the required ratios discussed above, we could request waivers from the lenders in our bank group. Although the lenders may not provide a waiver, we could take additional steps in the event of not meeting the required ratios or in the event of a reduction in the borrowing base below its current level of $205.0 million at one of the future redeterminations by the lenders. During 2010, we intend to use our surplus operating cash flows to reduce our outstanding debt. If it becomes necessary to pay debt down beyond operating cash flows, we could further reduce capital expenditures, continue to suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in the money derivative positions, further reduce operating and administrative costs, or take additional steps to increase liquidity. If we were unable to obtain a waiver and were unsuccessful at reducing our debt to the then necessary level, our debt could become due and payable upon acceleration by the lenders. To the extent that we do not enter into an agreement to refinance or extend the due date on the reserve-based credit facility, the outstanding debt balance at November 13, 2011, will become a current liability.

6. OIL AND NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	June 30, 2010	December 31, 2009
	(In 000 s)	
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 761,840	$ 756,461
Unproved property	36,814	37,147
Total property costs	798,654	793,608
Materials and supplies	3,960	4,312
Land	912	912
Total	803,526	798,832
Less: Accumulated depreciation, depletion and amortization	(239,623)	(186,207)
Natural gas properties and equipment, net	$ 563,903	$ 612,625

Impairment of Oil and Natural Gas Properties

In the six months ended June 30, 2010, we recorded a charge of approximately $0.6 million to impair the value of one of our wells located in the Woodford Shale in Oklahoma. For the six months ended June 30, 2009, we recorded a charge of approximately $4.0 million, to impair the value of certain of our wells located in the Woodford Shale in Oklahoma. This charge is included in depreciation, depletion and amortization in the Consolidated Statement of Operations. This impairment was recorded because the net capitalized costs 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 oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are level two inputs. The impairment is primarily caused by the impact of lower future natural gas prices. Cash flow estimates for the impairment testing exclude derivative instruments. As of June 30, 2010, we reviewed our 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 expected future long-term oil and natural gas prices continue to decline during 2010, the estimated undiscounted future cash flows for our proved oil and natural gas properties and other assets may not exceed the net capitalized costs related to our properties in the Cherokee Basin or in the Woodford Shale and a material non-cash impairment charge may be required to be recognized. The net capitalized cost subject to impairment in the Cherokee Basin is approximately $400.6 million and in the Woodford Shale is approximately $6.8 million.

Asset Sales

In the six months ended June 30, 2010, we sold miscellaneous equipment and surplus inventory for approximately $0.03 million and recorded a gain of approximately $0.01 million on the sales.

Useful Lives

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

Exploration and Dry Hole Costs

Our exploration and dry hole costs were $0.4 million and $0.2 million in the six months ended June 30, 2010 and 2009, respectively. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties.

7. RELATED PARTY TRANSACTIONS

Management Services Agreement

In November 2006, we 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. CEPM terminated the management services agreement effective December 15, 2009. Each quarter, CEPM charged us an amount for services provided to us. This amount was agreed to annually and included a portion of the compensation paid by CEPM and its affiliates to personnel who spent time on our business and affairs. The conflicts committee of our board of managers determined that the amounts paid by us for the services performed were fair to and in the best interests of the Company. These costs totaled approximately $0.6 million for the six months ended June 30, 2009.

We had a payable to Constellation of $0.4 million as of June 30, 2009. This payable balance is included in current liabilities in the accompanying balance sheets.

Natural Gas Purchases

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

Management Incentive Interests

CEPM holds the management incentive interests in CEP. These management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our limited liability company agreement) has been achieved and certain other tests have been met. For the three months ended June 30, 2010, 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, we increased our distribution rate to $0.5625 per unit. This increase in the distribution rate commenced a management incentive interest vesting period under our operating 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, we reduced our 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, the reserve was reduced to zero.

8. COMMITMENTS AND CONTINGENCIES

In the course of its normal business affairs, we are subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations and third-party litigation. As of June 30, 2010 and June 30, 2009, 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 our 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 10). 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. We are 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 our operating results from a termination of the sharing arrangement, Constellation Holdings, Inc.

(CHI) contributed $8.0 million to us in exchange for all of our Class D interests at the closing of its initial public offering in November 2006 for the purpose of partially protecting 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 10 and Note 15, the Class D interest special quarterly distributions have been suspended for all quarters commencing on or after January 1, 2008. This suspension includes approximately $2.9 million which represents the distributions that were suspended for the quarterly periods ended March 31, 2010, and December 31, September 30, June 30, and March, 31, 2009, and December 31, September 30, June 30, and March 31, 2008. Including the suspended distributions, the remaining undistributed amount of the Class D interests is $6.7 million. See Note 15 for additional information.

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9. ASSET RETIREMENT OBLIGATION

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

The following table is a reconciliation of the ARO:

	June 30, 2010	December 31, 2009
	(In 000 s)	
Asset retirement obligation, beginning balance	$ 12,129	$ 6,754
Liabilities incurred from acquisition of the properties		
Liabilities incurred	23	3,873
Liabilities settled	(32)	(12)
Revisions to prior estimates		1,108
Accretion expense	412	406
Asset retirement obligation, ending balance	$ 12,532	$ 12,129

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.

At June 30, 2010, and December 31, 2009, there were no assets legally restricted for purposes of settling existing asset retirement obligations.

10. NET PROFITS INTEREST

Certain of our 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. We record 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, 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 three months ended June 30, 2010 and 2009. As a result, no payments were made to the Trust with respect to the NPI for the three months ended June 30, 2010 and 2009.

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. 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 such agreement.

Litigation Related to Trust Termination

On January 25, 2008, Torch Royalty Company, Torch E&P Company, and CEP (collectively, the Claimants) commenced an arbitration proceeding before Judicial Arbitration and Mediation Services against 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 were similarly subject to net profit interests (the Other NPIs) that were also based on the gas purchase contract. The 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 were terminated. The Trustee took the position that the sharing arrangement under the gas purchase contract terminated upon the termination of the gas purchase contract. Trust Venture Company, LLC (Trust Venture) was permitted to intervene in the proceeding under an agreement whereby Trust Venture and its affiliates agreed to be bound by the formal award in the proceeding. On July 18, 2008, the arbitration panel issued its 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, and on December 10, 2008, the District Court of Harris County, Texas, 152nd Judicial District, dismissed the appeal of the final award filed by the Trustee and Trust Venture and confirmed the final award.

On January 8, 2009, we were 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. The Alabama court has made the Trust a nominal party to the Alabama litigation and ruled that the Trust is subject to regular discovery in the litigation. On August 18, 2009, Trust Venture filed an application for preliminary injunction requesting that the Alabama court enter an injunction requiring the Company to deposit into an escrow account all fees, less expenses, that it receives from water disposal under the Water Gathering and Disposal Agreement pending judgment in the lawsuit and asserting damages of approximately $11.6 million from June 2005 to May 2009. These alleged damages appear to be calculated based on a water gathering, separation and disposal fee of $0.05 per barrel notwithstanding the provisions of the Water Gathering and Disposal Agreement. After hearing, the Alabama court denied Trust Venture s application. On February 9, 2010, Trust Venture filed a motion for partial summary judgment seeking

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a determination regarding the applicability of a provision in the Conveyance related to the calculation of water handling charges, which motion the court denied on May 28, 2010, with the court ruling that our position with respect to the Conveyance provision was correct. No trial date has been set in the litigation. We intend to defend ourselves 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. We intend our forward-looking statements relating to the action to speak only as of the time of such statements and do not plan to update or revise them except to the extent that material information becomes available.

11. ENVIRONMENTAL LIABILITY

We are 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, 2010 and December 31, 2009, accrued environmental obligations were $0.2 million and $0.2 million, respectively. These obligations were classified as current liabilities on our Consolidated Balance Sheets.

12. UNIT-BASED COMPENSATION

We recognized approximately $1.0 million and $0.2 million of expense related to our unit-based compensation plans in the six months ended June 30, 2010, and June 30, 2009, respectively.

2010 Grants

Grants under the 2009 Omnibus Incentive Compensation Plan

In March 2010, we granted approximately 498,000 restricted common unit awards to certain employees in Texas under the 2009 Omnibus Incentive Compensation Plan. These units had a total fair market value of approximately $1.7 million based on the closing price of our common units on NYSE Arca on March 1, 2010. All of these service-based restricted units will vest on a five year ratable schedule beginning on March 1, 2010.

Grants under the Long-Term Incentive Program

We granted approximately 195,852 restricted common unit awards under the Long-Term Incentive Plan on March 1, 2010, to certain field employees in Alabama, Kansas, and Oklahoma and to certain employees in Texas. These units had a total fair market value of approximately $0.7 million based on the closing price of our common units on NYSE Arca on March 1, 2010. These service-based restricted units will vest on a three year ratable schedule beginning on March 1, 2010, except for certain employees in Texas which will vest on a five year ratable schedule beginning on March 1, 2010.

We granted approximately 54,747 restricted common unit awards under the Long-Term Incentive Plan on March 1, 2010, to our three independent managers. These units had a total fair market value of approximately $0.2 million based on the closing price of our common units on NYSE Arca on March 1, 2010. These awards will vest in full in March 2011.

13. DISTRIBUTIONS TO UNITHOLDERS

Distributions through June 30, 2010

Beginning in June 2009, we have suspended our quarterly distributions to unitholders to remain in compliance with the covenants associated with our reserve-based credit facility. The distribution must remain suspended until the outstanding debt balance, net of available cash, under our reserve-based credit facility is less than 90% of our borrowing base as determined by our lenders, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. See Note 15 for additional information.

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, we 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.

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14. MEMBERS EQUITY

2010 Equity

At June 30, 2010, we had 490,515 Class A units and 24,035,241 Class B units outstanding, which included 426,947 unvested restricted common units issued under our Long-Term Incentive Plan, 83,745 unvested restricted common units issued under our Executive Inducement Bonus Program, and 1,327,219 unvested restricted common units under our 2009 Omnibus Incentive Compensation Plan.

At June 30, 2010, we had granted 448,674 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 21,727 have vested.

At June 30, 2010, we had granted 146,551 common units of the 300,000 common units available under our Executive Inducement Bonus Program. Of these grants, 62,807 have vested.

At June 30, 2010, we had granted 1,541,252 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 214,033 have vested.

For the six months ended June 30, 2010, 75,452 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.3 million, have been returned to their respective plan and are available for future grants. See Note 15 for additional information.

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.

15. SUBSEQUENT EVENTS

The following subsequent events have occurred between July 1, 2010, and August 6, 2010:

Distribution

Our board of managers has suspended the quarterly distribution to our unitholders for the quarter ended June 30, 2010, which continues the suspension we first announced in June 2009.

Class D Interests

In connection with litigation related to the Torch NPI, we have suspended all quarterly cash contributions with respect to our Class D interests. This suspension, approved by our board of managers, includes the $0.3 million quarterly cash distribution for the three months ended June 30, 2010 and $2.9 million which represents the distributions that were suspended for the quarterly periods ended March 31, 2010, and December 31, September 30, June 30, and March 31, 2009, and December 31, September 30, June 30, and March 31, 2008. Including the suspended distributions, the remaining undistributed amount of the Class D interests is $6.7 million.

Members Equity

2010 Equity

At August 6, 2010, we had 489,356 Class A units and 23,978,465 Class B units outstanding, which included 341,544 unvested restricted common units issued under our Long-Term Incentive Plan, 83,745 unvested restricted common units issued under our Executive Inducement Bonus Program, and 1,303,904 unvested restricted common units under our 2009 Omnibus Incentive Compensation Plan.

At August 6, 2010, we had granted 405,879 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 64,335 have vested.

At August 6, 2010, we had granted 1,527,271 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 233,367 have vested.

From January 1, 2010, through August 6, 2010, 92,749 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.4 million, have been returned to their respective plan and are available for future grants.

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

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

Overview

We are a limited liability company formed by Constellation Energy Group, Inc. (Constellation) on February 7, 2005 to acquire oil and natural gas properties as well as related midstream assets. At June 30, 2010, our oil and natural gas reserves were 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 create long-term value and to generate stable cash flows allowing us to resume making quarterly cash distributions to our unitholders and over time to increase the amount of our future quarterly distributions. Our strategies for achieving this objective are to:

- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth;

- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through efficient hedging programs;

- make accretive acquisitions of oil and natural gas 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; and

- 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.

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, results of operations and prospects, 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 in production by drilling additional wells on our proven undeveloped, probable and possible locations on our existing properties and by acquiring additional reserves when opportunities arise. We will continue to focus on adding 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.

Since our initial public offering, 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).

- In September 2007, we completed the acquisition of additional oil and natural gas properties in the Cherokee Basin of Oklahoma (the Newfield Assets or Newfield Acquisition).

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

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, CE 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;
- exploration costs;
- (gain) loss from equity investment;
- unit based compensation programs;
- accretion of asset retirement obligation;
- unrealized (gain) loss on derivatives; and

realized loss (gain) on cancelled 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 a quarterly distribution or 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.

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

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2010	June 30, 2009	June 30, 2010	June 30, 2009
		(In 000 s)		
Reconciliation of Net Income (Loss) to Adjusted EBITDA:				
Net income (loss)	$ (21,092)	$ (16,744)	$ (3,034)	$ 2,190
Adjusted by:				
Interest expense/(income), net	3,387	3,278	7,443	6,119
Depreciation, depletion and amortization	26,733	18,195	53,981	32,629
Accretion of asset retirement obligation	205	56	412	157
(Gain)/loss on sale of assets	(5)	(3)	(13)	14
Exploration costs	224	103	447	206
(Gain)/loss on mark-to-market activities	4,549	12,134	(30,732)	(7,197)
Unit-based compensation programs	593	84	1,030	152
Unrealized loss/(gain) on natural gas derivatives/hedge ineffectiveness				267
Adjusted EBITDA	$ 14,594	$ 17,103	$ 29,534	$ 34,537

Significant Operational Factors

Realized Prices. Our average realized price for the six months ended June 30, 2010, including hedges, was $11.45 per Mcfe. This realized price includes the impact of $30.7 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, 2010 was $7.40 per Mcfe. Further deducting all hedge settlements, average realized prices were $4.90 per Mcfe excluding hedges.

Production. Our production for the six months ended June 30, 2010, was approximately 7.6 Bcfe, or an average of 42,017 Mcfe per day. This production is approximately 1.0 Bcfe, or 11.6%, lower in 2010 than in 2009. This decrease happened because we have reduced capital spending in 2010 and in 2009 below a maintenance level required to offset the natural decline rate associated with the natural gas production at our existing wells.

Capital Expenditures and Drilling Results. During 2010, we spent approximately $2.8 million in cash capital expenditures, primarily associated with our 2010 drilling program and to acquire additional interests in seven wells in the Black Warrior Basin and in the Cherokee Basin. We have drilled and completed 4 net wells and 4 net recompletions in the Cherokee Basin and we currently have 11 net wells and 3 net recompletions in progress. We expect to substantially complete our 2010 drilling program in the Cherokee Basin during the third quarter of 2010.

Reduction of Outstanding Debt. Through August 6, 2010, we have reduced our outstanding debt from a high of $220.0 million to $180.0 million, or by 18.2%.

Hedging Activities. As of June 30, 2010, all of our swaps and basis swaps are accounted for as mark-to-market derivatives. For the six months ended June 30, 2010, the unrealized non-cash mark-to-market gain was approximately $30.7 million as compared to an unrealized non-cash mark-to-market gain of $7.2 million for the same period in 2009. 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 Results 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

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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 32.

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, 2010	June 30, 2009	Variance $	Variance %	June 30, 2010	June 30, 2009	Variance $	Variance %
Revenues:								
Oil and gas sales	$ 27,078	$ 30,698	$ (3,620)	(11.8)%	$ 56,315	$ 63,560	$ (7,245)	(11.4)%
Gain (Loss) from mark-to-market activities	(4,549)	(12,134)	7,585	(62.5)%	30,732	7,197	23,535	327.0%
Total revenues	22,529	18,564	3,965	21.4%	87,047	70,757	16,290	23.0%
Operating expenses:								
Lease operating expenses	7,729	8,289	(560)	(6.8)%	15,692	17,074	(1,382)	(8.1)%
Cost of sales	585	612	(27)	(4.4)%	1,357	1,444	(87)	(6.0)%
Production taxes	677	560	117	20.9%	1,802	1,530	272	17.8%
General and administrative expenses	4,188	4,208	(20)	(0.5)%	9,250	9,441	(191)	(2.0)%
Exploration costs	224	103	121	117.5%	447	206	241	117.0%
(Gain) loss on sale of assets	(5)	(3)	(2)	66.7%	(13)	14	(27)	(192.9)%
Depreciation, depletion and amortization	26,733	18,195	8,538	46.9%	53,981	32,629	21,352	65.4%
Accretion expenses	205	56	149	266.1%	412	157	255	162.4%
Total operating expenses	40,336	32,020	8,316	26.0%	82,928	62,495	20,433	32.7%
Other expenses (income):								
Interest expense	3,275	2,723	552	20.3%	6,814	5,222	1,592	30.5%
Interest expense-(Gain)/loss from mark-to-market activities	113	555	(442)	(79.6)%	630	899	(269)	(29.9)%
Interest income	(1)		(1)		(1)	(2)	1	(50.0)%
Other (income) expense	(102)	10	(112)	(1,120)%	(290)	(47)	(243)	517.0%
Total other expenses (income)	3,285	3,288	(3)	(0.1)%	7,153	6,072	1,081	17.8%
Total expenses	43,621	35,308	8,313	23.5%	90,081	68,567	21,514	31.4%
Net income (loss)	$ (21,092)	$ (16,744)	$ (4,348)	(26.0)%	$ (3,034)	$ 2,190	$ (5,224)	(238.5)%
Net production:								
Total production (MMcfe)	3,745	4,242	(497)	(11.7)%	7,605	8,606	(1,001)	(11.6)%
Average daily production (Mcfe/d)	41,154	46,615	(5,461)	(11.7)%	42,017	47,547	(5,530)	(11.6)%
Average sales prices:								
Price per Mcfe including hedges[(a)]	$ 6.02	$ 4.38	$ 1.64	37.4%	$ 11.45	$ 8.22	$ 3.23	39.2%
Price per Mcfe excluding hedges	$ 4.18	$ 3.16	$ 1.02	32.2%	$ 4.90	$ 3.67	$ 1.23	33.5%
Average unit costs per Mcfe:								
Field operating expenses[(b)]	$ 2.24	$ 2.09	$ 0.15	7.2%	$ 2.30	$ 2.16	$ 0.14	6.4%
Lease operating expenses	$ 2.06	$ 1.95	$ 0.11	5.6%	$ 2.06	$ 1.98	$ 0.08	4.0%
Production taxes	$ 0.18	$ 0.13	$ 0.05	38.5%	$ 0.24	$ 0.18	$ 0.06	33.3%
General and administrative expenses	$ 1.12	$ 0.99	$ 0.13	13.1%	$ 1.22	$ 1.10	$ 0.12	10.9%
	$ 0.97	$ 0.97	$ 0.00	0.0%	$ 1.09	$ 1.08	$ 0.01	0.7%

General and administrative expenses w/o
unit-based compensation

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	For the Three Months Ended				For the Six Months Ended (Dollars in 000 s)			
	June 30, 2010	June 30, 2009	Variance $	Variance %	June 30, 2010	June 30, 2009	Variance $	Variance %
Depreciation, depletion and amortization[c]	$ 7.14	$ 4.29	$ 2.85	66.4%	$ 7.10	$ 3.79	$ 3.31	87.3%

(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, 2010 and 2009 cost per Mcfe was $6.99 and $3.45, respectively and $7.02 and $3.33 per Mcfe for the six months ended June 30, 2010 and 2009, respectively.

Three months ended June 30, 2010 compared to three months ended June 30, 2009

Oil and natural gas sales. Oil and natural gas sales decreased $3.6 million, or 11.8%, to $27.1 million for the three months ended June 30, 2010 as compared to $30.7 million for the same period in 2009. Of this decrease, $1.5 million was attributable to decreased production volumes and $5.9 million was attributable to our hedging program, offset by $3.8 million in higher market prices for oil and natural gas. Production for the three months ended June 30, 2010 was 3.7 Bcfe, which was 0.5 Bcfe lower than the same period in 2009. Of the decrease, 0.4 Bcfe was a reduction of natural gas production due to our suspension of our drilling programs in the Cherokee Basin starting in June 2009. The remaining decrease in production of 0.1 Bcfe was associated with our properties in the Black Warrior Basin and in the Woodford Shale. Due to the decrease in the level of our drilling activities, our 2009 and 2010 maintenance drilling programs will not be sufficient to offset the natural decline rate of production associated with our existing wells. We hedged approximately 82% of our actual production during the second quarter of 2010 and approximately 81% of our actual production during the same period in 2009.

As discussed below, the gain from our unrealized non-cash mark-to-market activities increased $7.6 million for the three months ended June 30, 2010, as compared to the same period in 2009. Our realized market prices before our hedging program increased from 2009 to 2010 primarily due to higher market prices for oil and natural gas. This was offset by the impact of our hedging program and the associated mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. As of June 30, 2010, all of our swaps and basis swaps are accounted for as mark-to-market derivatives. For the three months ended June 30, 2010, the unrealized non-cash mark-to-market loss was approximately $4.5 million as compared to an unrealized non-cash $12.1 million loss for the same period in 2009. This 2010 non-cash loss represents approximately $3.5 million from the impact of increased future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities and by a $1.0 million decrease for non-performance risk related to our counterparties. This 2009 non-cash loss represents approximately $13.1 million from the impact of increased 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.

Cash hedge settlements received for our commodity derivatives were approximately $11.4 million for the three months ended June 30, 2010. Cash hedge settlements received for our commodity derivatives were approximately $17.3 million for the three months ended June 30, 2009. This difference is primarily due to higher market prices and lower hedged volumes for natural gas during 2010.

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, 2010, lease operating expenses decreased $0.6 million, or 6.8%, to $7.7 million, compared to expenses of $8.3 million for the same period in 2009. This decrease in lease operating expenses is primarily related to $0.4 million in lower total spending in the Cherokee Basin and $0.2 million in lower expenses associated with our Woodford Shale properties. Our spending in the Black Warrior Basin during 2010 remained level with our spending in 2009. By category, our lease operating expenses were lower in 2010 as compared to 2009 by $0.6 million because of a decrease of $0.5 million in gas compression, $0.1 million in power and fuel, $0.1 million in field office expense, and $0.1 million in facilities expenses offset by an increase of $0.2 million in weather related road and lease maintenance.

For the three months ended June 30, 2010, per unit lease operating expenses were $2.06 per Mcfe compared to $1.95 per Mcfe for the same period in 2009. This increase is attributable to 11.7% lower production in 2010 as compared to the

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same period in 2009 offset by a decrease in total spending of 6.8% in 2010 as compared to the same period in 2009. Our per unit operating costs increased in the Cherokee Basin from $2.16 per Mcfe in 2009 to $2.32 per Mcfe in 2010 as a result of 0.4 Bcfe in lower production volumes and lower total spending.

For the three months ended June 30, 2010, production taxes increased $0.1 million, or 20.9%, to $0.7 million, compared to expenses of $0.6 million for the same period in 2009. This increase was primarily the result of higher market prices for oil and natural gas in 2010 offset by the impact of production taxes on 0.5 Bcfe in lower production.

Cost of sales. For the three months ended June 30, 2010, cost of sales decreased by approximately $0.02 million, or 4.4%, to $0.6 million, compared to $0.6 million for the same period in 2009. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower production volumes and higher market prices for natural gas, as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations.

General and administrative expenses decreased by approximately $0.02 million, or 0.5%, to $4.2 million for the three months ended June 30, 2010, as compared to $4.2 million for the same period in 2009. Our general and administrative expenses were lower in 2010 as compared to 2009 because of $0.3 million in lower management service fees and $0.2 million in lower labor costs offset by $0.5 million in higher non-cash unit-based compensation expenses. For the three months ended June 30, 2009, CEPM allocated $0.3 million in expenses to us for labor and other charges through the management services agreement.

Our per unit costs were $1.12 per Mcfe for the three months ended June 30, 2010 compared to $0.99 per Mcfe for the same period in 2009. This increase is attributable to a decrease in total spending of approximately less than $0.1 million offset by 0.5 Bcfe in lower production.

Exploration Costs. Exploration costs increased $0.1 million, or 117.5%, to $0.2 million for the three months ended June 30, 2010, as compared to $0.1 million for the same period in 2009. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment costs associated with leases on our unproved properties. The increase in 2010 is primarily as the result of the expectation that certain of our lease locations will expire as a result of a lower capital expenditure budget in 2010 and 2011 as compared to prior years.

Gain/loss on sale of assets. Our gain/loss on the sale of assets decreased less than $0.01 million, or 66.7%, to less than a $0.01 million loss for the three months ended June 30, 2010, as compared to a loss of less than $0.01 million for the same period in 2009. In 2010, we sold surplus equipment at a gain of less than $0.01 million.

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, 2010 was $26.7 million, or $7.14 per Mcfe, compared to $18.2 million, or $4.29 per Mcfe, for the same period in 2009. This increase in 2010 depreciation, depletion, and amortization reflects the impact of a lower year-end 2009 reserve base primarily due to price-related reserve revisions, capital expenditures for our development drilling programs, an impairment of $0.6 million for certain of one of our wells in the Woodford Shale, and a 0.5 Bcfe decrease in production volumes during 2010 as compared to 2009. We calculate depletion using units-of-production under the successful efforts method of accounting. Our other assets are depreciated using the straight line basis. Consistent with our prior practice, we will use our 2009 reserve report to calculate our depletion rate during the first three quarters of 2010. We expect our depletion rate during the first three quarters of 2010 to be approximately $7.08 per Mcfe. We will use our 2010 reserve report to record our depletion in the fourth quarter of 2010.

Interest expense. Interest expense for the three months ended June 30, 2010 increased $0.1 million to $3.4 million as compared to approximately $3.3 million in interest expense for same period in 2009. This increase was primarily due to $0.4 million in lower non-cash mark-to-market losses on our interest rate swaps that are accounted for as mark-to-market activities, lower interest rate swap settlements of $0.2 million, higher market interest rates of $0.7 million, and lower capitalized interest of $0.1 million during 2010 as compared to the same period in 2009. During 2009 and 2010, we used our excess operating cash flow to reduce our total debt from a high of $220.0 million to $180.0 million. At June 30, 2010, we had an outstanding balance under our reserve-based credit facility of $180.0 million as compared to $220.0 million at June 30, 2009. The average interest rate on our outstanding debt was approximately 5.8% in 2010 compared to 5.2% in 2009.

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Interest income. Interest income for the three months ended June 30, 2010 was less than $0.01 million as compared to less than $0.01 million in interest income for same period in 2009. During 2010, market rates for overnight investments continued to be at historical lows, resulting in no significant earnings on our 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 was available until December 31, 2009.

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 $4.3 million for the three months ended June 30, 2010, and as an unrealized loss of $11.4 million for the same period in 2009. This decrease reflects the difference in the settlements during 2010 and 2009, which are related to amounts previously included in locked accumulated other comprehensive income associated with our hedging positions previously accounted for as cash flow hedges. 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.

Six months ended June 30, 2010 compared to six months ended June 30, 2009

Oil and natural gas sales. Oil and natural gas sales decreased $7.2 million, or 11.4%, to $56.3 million for the six months ended June 30, 2010 as compared to $63.5 million for the same period in 2009. Of this decrease, $3.7 million was attributable to decreased production volumes and $12.9 million was attributable to our hedging program, offset by $9.4 million in higher market prices for oil and natural gas. Production for the six months ended June 30, 2010 was 7.6 Bcfe, which was 1.0 Bcfe lower than the same period in 2009. Of the decrease, 0.8 Bcfe was a reduction of natural gas production due to our suspension of our drilling programs in the Cherokee Basin starting in June 2009. The remaining decrease in production of 0.2 Bcfe was associated with our properties in the Black Warrior Basin and in the Woodford Shale. Due to the decrease in the level of our drilling activities, our 2009 and 2010 maintenance drilling programs will not be sufficient to offset the natural decline rate of production associated with our existing wells. We hedged approximately 81% of our actual production during 2010 and approximately 81% of our actual production during the same period in 2009.

As discussed below, the gain from our unrealized non-cash mark-to-market activities increased $23.5 million for the six months ended June 30, 2010, as compared to the same period in 2009. Our realized market prices before our hedging program increased from 2009 to 2010 primarily due to higher market prices for oil and natural gas. This was offset by the impact of our hedging program and the associated mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. As of June 30, 2010, all of our swaps and basis swaps are accounted for as mark-to-market derivatives. For the six months ended June 30, 2010, the unrealized non-cash mark-to-market gain was approximately $30.7 million as compared to an unrealized non-cash $7.2 million gain for the same period in 2009. This 2010 non-cash gain represents approximately $32.3 million from the impact of decreased future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities offset by a $1.6 million reduction for non-performance risk related to our counterparties. This 2009 non-cash gain represents approximately $7.1 million from the impact of decreased 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.

For the six months ended June 30, 2009, we recognized a loss of approximately $0.3 million related to hedge ineffectiveness primarily related to our hedges of production in the Cherokee Basin.

Cash hedge settlements received for our commodity derivatives were approximately $19.0 million for the six months ended June 30, 2010. Cash hedge settlements received for our commodity derivatives were approximately $32.3 million for the six months ended June 30, 2009. This difference is primarily due to higher market prices for natural gas and lower hedged volumes during 2010.

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, 2010, lease operating expenses decreased $1.4 million, or 8.1%, to $15.7 million, compared to expenses of $17.1 million for the same period in 2009. This decrease in lease operating expenses is primarily related to $1.0 million in lower total spending in the Cherokee Basin and $0.4 million in lower expenses associated with our Woodford Shale properties. Our spending in the Black Warrior Basin during 2010 remained level with our spending in 2009. By category, our lease operating expenses were lower in 2010 as compared to 2009 by $1.4 million because of a decrease of $0.6 million in gas compression, $0.3 million in field office expense, $0.2 million in facilities, $0.2 million in power and fuel and well servicing, and $0.1 million in pumping and gauging. For the six months ended June 30, 2010, per unit lease operating expenses were $2.06 per Mcfe compared to $1.98 per Mcfe for the same period in 2009. This increase is attributable to 11.6% lower production in 2010 as compared to the same period in 2009 offset by a decrease in total spending of 8.1% in 2010 as compared to the same period in 2009. Our per unit operating costs increased in the Cherokee Basin from

$2.17 per Mcfe in 2009 to $2.31 per Mcfe in 2010 as a result of 0.8 Bcfe in lower production volumes and lower total spending. Our production declines in the Cherokee Basin is the result of lower maintenance capital expenditures in 2010 and 2009.

For the six months ended June 30, 2010, production taxes increased $0.3 million, or 17.8%, to $1.8 million, compared to expenses of $1.5 million for the same period in 2009. This increase was primarily the result of higher market prices for oil and natural gas in 2010 offset by the impact of production taxes on 1.0 Bcfe in lower production.

Cost of sales. For the six months ended June 30, 2010, cost of sales decreased by approximately $0.1 million, or 6.0%, to $1.3 million, compared to $1.4 million for the same period in 2009. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower production volumes and higher market prices for natural gas, as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations.

General and administrative expenses decreased $0.2 million, or 2.0%, to $9.2 million for the six months ended June 30, 2010, as compared to $9.4 million for the same period in 2009. Our general and administrative expenses were lower in 2010 as compared to 2009 because of $1.0 million in lower management service fees, $0.3 million in consulting, and $0.1 million in lower legal fees offset by $0.8 million in higher non-cash unit-based compensation expenses, $0.2 million in higher professional services and tax consulting, and $0.2 million in higher rental expense. For the six months ended June 30, 2009, CEPM allocated approximately $1.0 million in expenses to us for labor and other charges through the management services agreement.

Our per unit costs were $1.22 per Mcfe for the six months ended June 30, 2010 compared to $1.10 per Mcfe for the same period in 2009. This increase is attributable to a decrease in total spending of approximately $0.2 million offset by 1.0 Bcfe in lower production. Approximately 58.0%, or $0.07 per Mcfe, of the increase is related to non-cash unit-based compensation costs.

Exploration Costs. Exploration costs increased $0.2 million, or 117.0%, to $0.4 million for the six months ended June 30, 2010, as compared to $0.2 million for the same period in 2009. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment costs associated with leases on our unproved properties. The increase in 2010 is primarily as the result of lease abandonments in Kansas and Oklahoma and the expectation that certain of our lease locations will expire as a result of a lower capital expenditure budget in 2010 and 2011 as compared to prior years.

Gain/loss on sale of assets. Our gain/loss on the sale of assets decreased $0.02 million, or 192.9%, to $0.01 million gain for the six months ended June 30, 2010, as compared to a loss of $0.01 million for the same period in 2009. In 2010, we sold surplus equipment at a gain of $0.01 million.

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 six months ended June 30, 2010 was $54.0 million, or $7.10 per Mcfe, compared to $32.6 million, or $3.79 per Mcfe, for the same period in 2009. This increase in 2010 depreciation, depletion, and amortization reflects the impact of a lower year-end 2009 reserve base primarily due to price-related reserve revisions, capital expenditures for our development drilling programs, an impairment of approximately $0.6 million for one of our wells in the Woodford Shale, and a 1.0 Bcfe decrease in production volumes during 2010 as compared to 2009. We calculate depletion using units-of-production under the successful efforts method of accounting. Our other assets are depreciated using the straight line basis. Consistent with our prior practice, we will use our 2009 reserve report to calculate our depletion rate during the first three quarters of 2010. We expect our depletion rate during the first three quarters of 2010 to be approximately $7.08 per Mcfe. We will use our 2010 reserve report to record our depletion in the fourth quarter of 2010.

Interest expense. Interest expense for the six months ended June 30, 2010 increased $1.3 million, or 21.6%, to $7.4 million as compared to approximately $6.1 million in interest expense for same period in 2009. This increase was primarily due to $0.3 million in lower non-cash mark-to-market losses on our interest rate swaps that are accounted for as market-to-market activities, higher interest rate swap settlements of $0.4 million, higher market interest rates of $1.0 million, and lower capitalized interest of $0.2 million during 2010 as compared to the same period in 2009. During 2009 and 2010, we used our excess operating cash flow to reduce our total debt from a high of $220.0 million to $180.0 million. At June 30, 2010, we had an outstanding balance under our reserve-based credit facility of $180.0 million as compared to $220.0 million at June 30, 2009. The average interest rate on our outstanding debt was approximately 5.8% in 2010 compared to 5.2% in 2009.

Interest income. Interest income for the six months ended June 30, 2010 was less than $0.01 million as compared to less than $0.01 million in interest income for same period in 2009. During 2010, market rates for overnight investments continued to be at historical lows, resulting in no significant earnings on our 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 was 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 previously designated cash-flow hedge positions. At June 30, 2010, the balance was an unrealized gain of $18.8 million compared to an unrealized gain of $28.4 million at December 31, 2009. This decrease reflects the amortization to earnings as the derivative positions that were previously accounted for as cash flow hedges settled during the first and second quarters of 2010.

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 $9.5 million for the six months ended June 30, 2010, and as an unrealized loss of $3.6 million for the same period in 2009. This decrease reflects the settlements during 2010 related to amounts previously included in locked accumulated other comprehensive income associated with our hedging positions previously accounted for as cash flow hedges. 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.

Liquidity and Capital Resources

During 2009 and 2010, we utilized our cash flow from operations as our primary source of capital. Our primary use of capital during this time was for the retirement of outstanding debt. We have successfully reduced our outstanding indebtedness by $40.0 million since we suspended our quarterly distribution to unitholders in June 2009. Based upon our current business plan for 2010, we expect to continue to generate operating cash flows in excess of our working capital needs and planned capital expenditures. We expect to make limited maintenance capital expenditures of approximately $10.0 million to $12.0 million primarily concentrated in the Cherokee Basin through the third quarter of 2010. The primary focus of our business plan in 2010 will be to use our excess operating cash flows to further reduce our outstanding debt level.

Our reserve-based credit facility currently provides a limited availability to finance future maintenance capital expenditures and other working capital needs. As of June 30, 2010, our borrowing base under our reserve-based credit facility was $205.0 million and we had $180.0 million of debt outstanding under our reserve-based credit facility, leaving us with $25.0 million in unused borrowing capacity. As of June 30, 2010, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to make distributions, and our borrowings outstanding, net of available cash, under our reserve-based credit facility exceeded 90% of the borrowing base.

Our reserve-based credit facility matures on November 13, 2012. In the first quarter of 2008, we filed a shelf registration statement with the SEC to register up to $1.0 billion of debt and equity securities. This registration statement expires January 30, 2011. There is no guarantee that securities can or will be issued under the registration statement. Our current reserve-based credit facility is also subject to future borrowing base redeterminations and will have to be renewed or replaced before its maturity in November 2012.

As we pursue our business plan, we will be monitoring the capital resources available to us to meet our future financial obligations and planned limited maintenance capital expenditures in 2010. 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 32. During 2010 and 2011, we expect to fund our working capital needs and any maintenance capital expenditures with cash flow from operations. Our current expectation is that we will manage our business to operate within the cash flows that are generated. During 2010, we intend to limit our capital expenditures and to use any surplus operating cash flows to further reduce our debt level. We expect to complete substantially all of our 2010 drilling activities in the Cherokee Basin during the third quarter of 2010. We expect that the 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. During 2009 and 2010, we have successfully reduced our outstanding debt balances from a high of $220.0 million to $180.0 million. Any future quarterly distribution to unitholders cannot be made when our borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. We are subject to additional future borrowing base redeterminations and cannot forecast the level at which our lenders may set our borrowing base. However, after our outstanding debt balance, net of available cash, is less than 90% of our borrowing base as determined by our lenders and at such time we are able to resume maintenance capital expenditures, we will evaluate the resumption of our quarterly distribution to unitholders. This evaluation will consider our outstanding borrowings and cash reserves that are set by our board of managers for the proper conduct of our business. Given our focus on debt reduction, we anticipate that our distribution will remain suspended through the fourth quarter of 2010. Any future quarterly distributions must be approved by our board of managers.

Reserve-based credit facility

On November 13, 2009, we entered into an amended and restated $350.0 million reserve-based credit facility with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders. The reserve-based credit facility amends, extends, and consolidates our previous reserve-based credit facilities and matures on November 13, 2012. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The current lenders and their percentage commitments in the reserve-based credit facility are: The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), Wells Fargo Bank, N.A. (14.63%), and Societe Generale (14.63%).

The amount available for borrowing at any one time under the reserve-based credit facility is limited to the borrowing base for our oil and natural properties in Alabama, Kansas, and Oklahoma. As of August 6, 2010, our borrowing base was reaffirmed by our banks at $205.0 million. The borrowing base is redetermined semi-annually, and may be redetermined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, together with, among other things, the oil and natural gas prices prevailing at such time. Our next semi-annual borrowing base redetermination is scheduled during the fourth quarter of 2010. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Borrowings under the reserve-based credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the reserve-based credit facility, working capital and general limited liability company purposes. The reserve-based credit facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit. As of June 30, 2010, no letters of credit are outstanding.

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

The reserve-based credit facility contains various covenants that limit, among other things, our ability and certain of our subsidiaries ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and make distributions to unitholders.

In addition, we are required to maintain (i) a ratio of (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents, and cash reserves of the Company)) to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus (minus) the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives, and other similar charges) of not more than 3.75 to 1.0 through September 30, 2010 and 3.50 to 1.0 thereafter; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143 (including the current liabilities in respect of the termination of natural gas and interest rate swaps). All financial covenants are calculated using our consolidated financial information.

The reserve-based credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments,

guaranties not being valid under the reserve-based credit facility and a change of control. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of August 6, 2010, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to make distributions, and our borrowings outstanding, net of available cash, under our reserve-based credit facility exceeded 90% of the borrowing base.

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

The reserve-based credit facility contains no covenants related to our relationship with Constellation or Constellation s right to appoint all of the Class A managers of our board of managers.

At June 30, 2010, we believe that we were in compliance with the financial covenant ratios contained in our reserve-based credit facility. We monitor compliance on an ongoing basis. As of June 30, 2010, our actual Total Net Debt less Available Cash to Adjusted EBITDA ratio was 2.7 to 1.0 as compared with a required ratio of not greater than 3.75 to 1.0, our actual ratio of consolidated current assets to consolidated current liabilities was 3.5 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 8.2 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If we are unable to remain in compliance with the debt covenants associated with our reserve-based credit facility or maintain the required ratios discussed above, we could request waivers from the lenders in our bank group. Although the lenders may not provide a waiver, we could take additional steps in the event of not meeting the required ratios or in the event of a reduction in the borrowing base below its current level of $205.0 million at one of the future redeterminations by the lenders. During 2010, we intend to use our surplus operating cash flows to reduce our outstanding debt. If it becomes necessary to pay debt down beyond operating cash flows, we could further reduce capital expenditures, continue to suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in the money derivative positions, further reduce operating and administrative costs, or take additional steps to increase liquidity. If we were unable to obtain a waiver and were unsuccessful at reducing our debt to the necessary level, our debt could become due and payable upon acceleration by the lenders. To the extent that we do not enter into an agreement to refinance or extend the due date on the reserve-based credit facility, the outstanding debt balance at November 13, 2011, 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 facility. These positions are outlined on page 38.

Cash Flow from Operations

Our net cash flow provided by operating activities for the six months ended June 30, 2010 was $19.3 million, compared to net cash flow provided by operating activities of $29.6 million for the same period in 2009. This decrease in operating cash flow was primarily attributable to lower oil and natural gas sales of $7.2 million as the result of 1.0 Bcfe in lower natural gas production in 2010. For 2010, our operating cash flows were increased by $16.8 million related to cash hedge settlements for our natural gas commodity and interest rate derivatives. Our change in working capital from 2009 to 2010 was impacted by lower accrued liabilities of $3.2 million, lower royalties payable of $1.7 million, lower accounts receivable of $1.4 million, higher accounts payable of $0.2 million, and lower payables to CCG of $0.1 million. Our accrued liabilities decreased with

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the payments associated with our 2009 incentive compensation programs. Our accounts payable increased due to timing of invoice payments to vendors associated with our 2010 capital program. Our receivables balance decreased due to lower volumes of natural gas sold in 2010 offset by higher current period prices for our current estimated natural gas sales. The royalties payable, which represents the amount of monies owed to the royalty owners in our properties for our monthly oil and natural gas sales, decreased due to lower production of natural gas reducing the amount of royalties owed. The decrease in payables to CCG was impacted by the termination of the management services agreement in December 2009.

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 35.

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 the negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. To the extent market prices exceed our hedge 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 will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

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

The following tables summarize, for the periods indicated, our hedges currently in place through December 31, 2014. All of these derivatives are accounted for as mark-to-market activities.

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
2010					2,670,000	$ 8.13	2,700,000	$ 8.15	5,370,000	$ 8.14
2011	2,400,000	$ 8.55	2,425,000	$ 8.55	2,220,000	$ 8.45	2,220,000	$ 8.45	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	2,025,000	$ 7.33	2,079,500	$ 7.32	2,070,000	$ 7.33	2,038,000	$ 7.34	8,212,500	$ 7.33
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
									38,190,000	

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

2010							180,000	$	7.91	180,000	$	7.91	360,000	$	7.91
2011	180,000	$	7.93	180,000	$	7.93	180,000	$	7.93	180,000	$	7.93	720,000	$	7.93
													1,080,000		

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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 $
2010					2,180,768	$ 0.73	2,070,895	$ 0.72	4,251,663	$ 0.72
2011	1,923,618	$ 0.63	1,742,610	$ 0.67	1,470,900	$ 0.66	1,393,700	$ 0.68	6,530,828	$ 0.66
2012	1,502,800	$ 0.58	1,427,100	$ 0.59	1,352,900	$ 0.61	1,295,900	$ 0.62	5,578,700	$ 0.60
2013	1,245,400	$ 0.40	1,192,900	$ 0.40	1,145,700	$ 0.40	1,104,400	$ 0.40	4,688,400	$ 0.40
2014	533,400	$ 0.42	513,800	$ 0.42	495,400	$ 0.42	479,350	$ 0.42	2,021,950	$ 0.42
									23,071,541	

Investing Activities Acquisitions and Capital Expenditures

Cash used in investing activities was $2.6 million for the six months ended June 30, 2010, compared to $20.6 million for the same period in 2009. Our cash capital expenditures were $2.8 million in 2010, of which $2.3 million related to drilling expenditures for our 2010 capital program in the Cherokee Basin and $0.5 million related to the acquisition of additional interests in seven natural gas wells in the Cherokee Basin and in the Black Warrior Basin. We have drilled and completed 4 net wells and 4 net recompletions in the Cherokee Basin and we currently have 11 net wells and 3 net recompletions in progress. We have used $0.4 million of our materials and supplies inventory in our current drilling and workover programs and expect to use an additional $1.3 million in inventory during the third and fourth quarters. We do not plan on restocking the inventory items that we use. We also do not plan to resume drilling in the Black Warrior Basin during 2010.

Our capital expenditures were $20.8 million for the six months ended June 30, 2009, which primarily related to drilling and development of oil and natural gas properties in the Cherokee Basin. Through June 30, 2009, we drilled and completed 60 net wells and 17 net recompletions in the Cherokee Basin. We also prepared 10 drilling locations in the Black Warrior Basin, of which 9 remain available for us to drill on in the future.

We currently anticipate our total capital budget will be between $10.0 million and $12.0 million for the twelve months ending December 31, 2010. This capital budget primarily consists of capital for drilling wells and recompletions and also includes amounts for infrastructure projects, equipment, and inventory. The 2010 budget is set below our 2010 estimated maintenance capital level of $25.3 million. Our capital spending in 2010 has been reduced from our 2009 spending level of $22.9 million and our 2008 spending level of $47.9 million. We expect to spend substantially the remainder of our 2010 capital budget in the Cherokee Basin during the third quarter of 2010 and have not planned for any investment capital expenditures. We expect that our current and future capital expenditures will be funded using our cash flow from operations. Because we have reduced capital spending in 2010 and in 2009 below a maintenance level, we anticipate lower production in 2010 which may reduce our operating cash flows. Once market conditions warrant, we expect to resume capital spending at a level sufficient to maintain our then current production rate. The amount and timing of our capital expenditures is largely discretionary and within our control. If natural gas prices decline to levels below acceptable levels, and the total borrowing base under our reserve-based credit facility is further reduced, or drilling costs escalate, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and crews. Based upon current natural gas price expectations and expected production levels, we anticipate that our cash flow from operations and available borrowing capacity under our reserve-based credit facility will meet our planned capital expenditures and other cash requirements for the twelve months ending December 31, 2010. In 2010, we expect that our excess operating cash flows will be used to reduce our outstanding debt level. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures. Our capital expenditures are also impacted by drilling and service costs. In the event of inflation increasing drilling and service costs, our hedging program will limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending.

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Financing Activities

Our net cash used in financing activities was $15.4 million for the six months ended June 30, 2010, compared to $1.5 million provided by financing activities for the same period in 2009. During 2010, we used $15.0 million in operating cash flows to reduce our outstanding debt level from $195.0 million to $180.0 million or by 7.7%. In November 2009, we entered into an amended and restated credit facility that matures in November 2012. At June 30, 2010, we have approximately $4.6 million in debt issue costs remaining to be amortized through November 2012.

We have suspended $2.9 million in quarterly distributions on the Class D interests associated with each of the quarterly periods since 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 reserve-based credit facility and limited liability company agreement. We have suspended our quarterly distributions to unitholders since the quarter ended June 30, 2009, to reduce our outstanding indebtedness. Given our current focus on debt reduction, we anticipate that our distribution will remain suspended through the fourth quarter of 2010. Assuming that the quarterly distribution rate would have remained at $0.13 per unit for each quarter in 2010, this suspension of the quarterly distribution would provide approximately $12.8 million in cash flow during 2010 that could be used to reduce our outstanding debt balance under our reserve-based credit facility. For additional information, refer to *Outlook* on page 35.

Our net cash provided by financing activities was $1.5 million for the six months ended June 30, 2009. 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.

Contractual Obligations

At June 30, 2010, we had the following contractual obligations or commercial commitments:

	Payments Due By Year[(1)(2)]						
	2010	2011	2012	2013	2014	Thereafter	Total
	(In thousands)						
Reserve-based credit facility	$	$	$ 180,000	$	$	$	$ 180,000
Support Services Agreement	1,265						1,265
Offices Leases	414	416	424	408	422	752	2,836
Total	$ 1,679	$ 416	$ 180,424	$ 408	$ 422	$ 752	$ 184,101

(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 5.8% at June 30, 2010.

At June 30, 2010, our asset retirement obligation was approximately $12.5 million.

Off-Balance Sheet Arrangements

We have no off-balance sheet debt to any third parties or related 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

Our internal risk committee actively monitors 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 6, 2010, we have not suffered any losses with our counterparties as a result of nonperformance.

Certain key counterparty relationships are described below:

Macquarie Energy LLC

Macquarie Energy LLC (Macquarie), a subsidiary of Sydney, Australia-based Macquarie Group, Ltd., purchases a portion of our natural gas production in the Cherokee Basin. We have received a guarantee from Macquarie Bank Limited for up to $8.0 million in purchases through December 31, 2011. As of August 6, 2010, we have no past due receivables from Macquarie.

Scissortail Energy, LLC

Scissortail Energy, LLC (Scissortail), a subsidiary of Copano Energy, L.L.C., purchases a portion of our natural gas production in Oklahoma and Kansas. As of August 6, 2010, we have no past due receivables from Scissortail.

ONEOK Energy Services Company, L.P.

ONEOK Energy Services Company, L.P. (ONEOK), a subsidiary of ONEOK, Inc., purchases a portion of our natural gas production in Oklahoma and Kansas. As of August 6, 2010, we have no past due receivables from ONEOK.

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 2010. As of August 6, 2010, we have no past due receivables from J.P. Morgan Ventures Energy Corporation.

Derivative Counterparties

As of August 6, 2010, all of our derivatives are with BNP Paribas, The Royal Bank of Scotland plc, Societe Generale, Wells Fargo Bank, N.A. and The Bank of Nova Scotia. These banks are lenders who participate in our reserve-based credit facility. All of our derivatives are collateralized by the assets securing our reserve-based credit facility and therefore currently do not require the posting of cash collateral. As of August 6, 2010, each of these financial institutions has an investment grade credit rating.

Reserve-Based Credit Facility

As of August 6, 2010, the banks and their percentage commitments in our reserve-based credit facility are: The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), Wells Fargo Bank, N.A. (14.63%), and Societe Generale (14.63%). As of August 6, 2010, each of these financial institutions has an investment grade credit rating.

Outlook

During 2010, we expect that our business will continue to be affected by the factors described in Part II, Item 1A. Risk Factors, as well as the following key industry and economic trends. Our expectation is based upon key assumptions and information currently available to us. To the extent that our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Full Year 2010 Expected Results

Our 2010 business plan and forecast is focused on reducing our outstanding debt level and promoting financial flexibility by further enhancing our liquidity position. This plan will result in limited maintenance capital expenditures and the continued suspension of our quarterly distribution through the fourth quarter of 2010. Our current goal is to sustain the company through the current business cycle and to further reduce our debt level so that we can resume maintenance capital expenditures. Ultimately we intend to position our operations to create long-term value. As market conditions warrant, we expect to resume maintenance capital expenditures. We also intend to evaluate the possibility of a resumption of a limited quarterly distribution for the first quarter of 2011. We expect our full year 2010 results to be impacted by declining production of natural gas, further commodity price volatility, continued limited ability to access our reserve-based credit facility, and weak economic activity muting the demand and prices for oil and natural gas in our market areas. Our actual operating and financial results through June 30, 2010, are consistent with the expectations that have been outlined in our 2010 business plan and forecast.

We currently anticipate:

- Our production to be between 14.5 Bcfe and 15.5 Bcfe.

Our operating expenses to be relatively flat with our 2009 operating expenses, resulting in a range of $52.0 million to $56.0 million.

Our total capital expenditures to be between $10.0 million and $12.0 million, which assumes a decline rate of 15 percent and a dollar per flowing Mcfe range of $4,400 to $4,700. This capital budget has been reduced to a level below our estimated maintenance level of capital expenditures of approximately $25.3 million. We expect to drill and complete approximately 25 net wells and recompletions, primarily in the Cherokee Basin. We will review our drilling and recompletion opportunities and anticipate allocating capital to the highest value-added projects across all of our available opportunities.

We anticipate that any possible future distribution levels in 2011 will be set at a sustainable rate based on our operating results, the market prices for oil and natural gas and our projected business plan being achieved. All future quarterly distributions must be approved by our board of managers.

Impact of 2010 Plan

We currently prepare a five-year plan to manage our business. Our goal is to maintain production rates and operating cash flows at a steady level by developing our proved undeveloped reserve locations each year. During 2010 the focus of our business plan is to further reduce our outstanding debt by reducing maintenance capital expenditures and continuing the suspension of our quarterly distribution to unitholders. Subject to market conditions, this may position us to resume maintenance capital expenditures in 2011 through 2014. We expect that this plan will result in lower production levels in 2010. If we resume maintenance capital expenditures in 2011, it will likely result in production levels at or near our 2010 production run rates in 2011 through 2014. This plan is expected to reduce our leverage, improve our liquidity position, and reduce future cash interest expenses on our outstanding unhedged debt.

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, 2010, 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, 2009. 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 January 2010, the FASB issued its final guidance on additional supplemental fair value disclosures. Two new disclosures will be required: (1) a gross presentation of activities (purchases, sales, and settlements) within the Level 3 roll forward reconciliation, which will replace the net presentation format, and (2) detailed disclosures about the transfers between Level 1 and 2 measurements. The guidance also provides several clarifications regarding the level of disaggregation and disclosures about inputs and valuation techniques. The new disclosures are effective this quarter for calendar year-end companies, except for the Level 3 gross activity disclosures, which will be deferred until the first quarter of 2011. The adoption of this guidance did not have a material impact on our financial statements or our disclosures.

In February 2010, the FASB amended its guidance on subsequent events. SEC filers are now not required to disclose the date through which an entity has evaluated subsequent events. The amended guidance was effective upon issuance. The adoption of this guidance did not have a material impact on our financial statements or our disclosures.

New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2010, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. We are currently reviewing the recently issued standards and interpretations but none are expected to have a material impact on our financial statements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators 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.

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Global Financial and Energy Markets

During 2009 and 2008, there was unprecedented volatility in the global financial and energy markets. Additionally, the economic recession reduced the demand for oil and natural gas, which negatively impacted market prices for these products.

We expect that our ability to issue debt and equity may be limited over the next year, that the borrowing base of our reserve-based credit facility could potentially be reduced if future expected market prices for natural gas decline further, 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. In response to the credit crisis and the decline in the market prices for oil and natural gas, we have suspended our cash distribution since June 2009 and lowered our maintenance capital spending in 2009 and 2010. We expect that if market prices for natural gas remains depressed, our future cash flows from operations will be reduced for our unhedged production. We continue to monitor the financial and energy markets to determine if we should further revise the timing and scope of our future drilling programs, financing activities, and acquisition activities to determine the impact of these activities on cash distributions to our unitholders.

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, 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. We are currently operating in an environment characterized by low natural gas prices which will lower our revenues that we realize on our unhedged natural gas production and limit the amount of operating cash flows available for maintenance capital expenditures, distributions to unitholders, or reducing our outstanding debt level. 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 available 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 our derivative transactions with counterparties that are lenders in our reserve-based credit facility. The table below presents the hypothetical changes in fair values arising from potential changes in the quoted market prices of the commodity underlying the derivative instruments used to mitigate these market risks. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the sale of the hedged 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, 2010	$ 83,479	$ 64,127	$ (19,352)	$ 102,831	$ 19,352

Interest Rate Risk

At June 30, 2010, the one-month LIBOR rate was 0.348%, the three-month LIBOR rate was 0.534%, and our applicable margin on LIBOR borrowings was 3.25%. At June 30, 2010, the ABR rate was 3.25%, and our applicable margin on ABR borrowings was 3.25%. At June 30, 2010, we had debt outstanding of $180.0 million. This entire amount incurred interest at a rate of a three-month LIBOR rate plus an applicable margin of 3.25% based on utilization. We had no debt outstanding at the one-month LIBOR rate or at the ABR rate. At June 30, 2010, the carrying value and fair value of our debt is $180.0 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.

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		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Increase (in 000 s)	Fair Value	(Decrease)
Impact of changes in LIBOR on derivative interest rate instruments at June 30, 2010	$ (4,968)	$ (4,513)	$ 455	$ (5,423)	$ (455)

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, 2010, we have the following outstanding interest rate swaps that fix our LIBOR rate:

Maturity Date	Total Debt Hedged (in 000 s)	LIBOR Fixed Rate
August 21, 2010	$ 28,500	2.74%
September 21, 2010	$ 11,000	2.66%
October 22, 2010	$ 19,000	2.91%
August 20, 2012	$ 11,000	2.75%
September 20, 2012	$ 45,000	3.03%
October 19, 2012	$ 29,500	3.21%
October 22, 2012	$ 7,500	3.06%

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 three months ended June 30, 2010, 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

Litigation Related to Trust Termination

On January 25, 2008, Torch Royalty Company, Torch E&P Company, and CEP (collectively, the Claimants) commenced an arbitration proceeding before Judicial Arbitration and Mediation Services against 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 were similarly subject to net profit interests (the Other NPIs) that were also based on the gas purchase contract. The 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 were terminated. The Trustee took the position that the sharing arrangement under the gas purchase contract terminated upon the termination of the gas purchase contract. Trust Venture Company, LLC (Trust Venture) was permitted to intervene in the proceeding under an agreement whereby Trust Venture and its affiliates agreed to be bound by the formal award in the proceeding. On July 18, 2008, the arbitration panel issued its 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, and on December 10, 2008, the District Court of Harris County, Texas, 152nd Judicial District, dismissed the appeal of the final award filed by the Trustee and Trust Venture and confirmed the final award.

On January 8, 2009, we were 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. The Alabama court has made the Trust a nominal party to the Alabama litigation and ruled that the Trust is subject to regular discovery in the litigation. On August 18, 2009, Trust Venture filed an application for preliminary injunction requesting that the Alabama court enter an injunction requiring the Company to deposit into an escrow account all fees, less expenses, that it receives from water disposal under the Water Gathering and Disposal Agreement pending judgment in the lawsuit and asserting damages of approximately $11.6 million from June 2005 to May 2009. These alleged damages appear to be calculated based on a water gathering, separation and disposal fee of $0.05 per barrel notwithstanding the provisions of the Water Gathering and Disposal Agreement. After hearing, the Alabama court denied Trust Venture s application. On February 9, 2010, Trust Venture filed a motion for partial summary judgment seeking a determination regarding the applicability of a provision in the Conveyance related to the calculation of water handling charges, which motion the court denied on May 28, 2010, with the court ruling that our position with respect to the Conveyance provision was correct. No trial date has been set in the litigation. We intend to defend ourselves 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. We intend our forward-looking statements relating to the action to speak only as of the time of such statements and do not plan to update or revise them except to the extent that material information becomes available.

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 the year ended December 31, 2009 that was filed on February 25, 2010. 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 2009 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.

Risks Related to Financing and Credit Environment

Government regulations regarding derivatives could adversely impact our ability to engage in commodity price risk management activities.

We use derivative instruments to manage our commodity price and interest rate risk. The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which was signed into law in July 2010, contains measures aimed at increasing the transparency and stability of the over-the-counter, or OTC, derivative markets and preventing excessive speculation. The Dodd-Frank Act could restrict, among other things, trading positions in the energy futures markets, require different collateral or settlement positions, or increase regulatory reporting over derivative positions. Based on the provisions included in the Dodd-Frank Act and the implementation of regulations yet to be developed, these changes could, among other things, impact our ability to hedge commodity price and interest rate risk or increase the costs associated with our hedging programs, and such impact could be material to our revenues and operating cash flows.

Tax Risks to Unitholders

The value of an investment in our units could be affected by recent and potential federal tax increases.

Absent new legislation extending the current rates, in taxable years beginning after December 31, 2010, the highest marginal United States federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. These rates are subject to change by new legislation at any time.

The recently enacted Health Care and Education Reconciliation Act of 2010 includes a provision that, in taxable years beginning after December 31, 2012, subjects certain individuals, estates and trusts to an Unearned Income Medicare Contribution tax of 3.8% on certain income. In the case of an individual having a modified adjusted gross income in excess of $200,000 (or $250,000 for married taxpayers filing joint returns), the provision imposes a tax equal to 3.8% of the lesser of such excess and the individual s net investment income, which will include net income and gain from the ownership or disposition of our units.

These recent federal tax increases, and any other future potential federal tax increases, may negatively impact the value of an investment in our common units.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, the ability to take certain operations-related deductions, including deductions for intangible drilling costs and percentage depletion and deductions for United States production activities. Other proposed changes may affect our ability to remain taxable as a partnership for federal income tax purposes. We are unable to predict whether any changes, or other proposals to such laws, ultimately will be enacted. Any such changes could negatively impact the value of an investment in our common units.

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

Unitholders are required to pay 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. For example, we may sell a portion of our properties and use the proceeds to pay down debt or acquire other properties rather than distributing the proceeds to our unitholders. Our unitholders may be allocated substantial taxable income with respect to that sale.

Based on our 2010 business plan and forecast, we do not currently anticipate resuming a cash distribution in 2010 and we anticipate making limited maintenance capital expenditures. If we generate taxable income for the 2010 tax year, our unitholders will not receive cash distributions from us during 2010 in an amount sufficient to pay any actual tax liability that results from their share of such 2010 taxable income.

A unitholder s share of our taxable income, gain, loss and deduction, or specific items thereof, may be substantially different than the unitholder s interest in our economic profits.

A unitholder s share of our taxable income and gain (or specific items thereof) may be substantially greater than, or our tax losses and deductions (or specific items thereof) may be substantially less than, the unitholder s interest in our economic profits. This may occur, for example, in the case of a unitholder who purchases units at a time when the value of our units or of one or more of our properties is relatively low or a unitholder who acquires units directly from us in exchange for property whose fair market value exceeds its tax basis at the time of the exchange.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704 of the Internal Revenue Code and changing the treatment of certain types of income earned from profits or carried interests. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Any modification to the U.S. federal income tax laws and interpretations thereof could make it more difficult or impossible to i) meet the exception, which we refer to as the qualifying income exception, for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, ii) affect or cause us to change our business activities, iii) affect the tax considerations of an investment in us, iv) change the character or treatment of portions of our income or v) adversely affect an investment in our common units. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interests within a twelve-month period.

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. A constructive termination results in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one fiscal year, the cost of which would be borne by our unitholders, and could result in a deferral of depreciation deductions allowable in computing our taxable income. We technically terminated for tax purposes for the 2009 tax year and incurred additional costs as a result of the termination. We are not able to control or to predict if or when we may technically terminate for tax purposes in the future.

In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. When treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

Unitholders may be subject to state and local taxes and return filing requirements.

We currently do business and own assets in Alabama, Kansas, and Oklahoma. We are registered to do business in Texas. Each of these states, except Texas, imposes an income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may do business or own assets in other states in the future.

Some of the states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a common unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular common unitholder's income tax liability to the state, generally does not relieve a nonresident common unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to common unitholders for purposes of determining the amounts distributed by us.

It is the sole responsibility of each unitholder to file all United States federal, foreign, state and local tax returns that may be required of such unitholder.

Forward-Looking Statements

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

- the volatility of realized oil and natural gas prices;
- the conditions of the capital markets, inflation, interest rates, availability of 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 ability to extend or refinance our reserve-based credit facility;

the level of our borrowing base under our reserve-based credit facility;

the resumption, timing or amount of our cash distribution;

the impact from any termination of the NPI sharing arrangement or any change in the calculation of the NPI;

our hedging program and our derivative positions;

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- our production volumes;
- our lease operating expenses, general and administrative costs and finding and development costs;
- the availability of drilling and production equipment, labor and other services;
- our future operating results;
- our prospect development and property acquisitions;
- the marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of the current global credit and economic environment;
- the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, tornados, earthquakes, snow and ice storms and other catastrophic events and natural disasters;
- governmental regulation, including environmental regulation, and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas producing countries;
- support from our former sponsor or a change in any 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. In some cases, forward-looking statements can be identified by terminology such as may, could, should, expect, plan, project, anticipate, believe, estimate, predict, potential, pursue, target, continue, the negative of such terms or other comparable terminology

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

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, 2010 and June 30, 2009 and six months ended June 30, 2010 and June 30, 2009

Consolidated Balance Sheets Constellation Energy Partners LLC at June 30, 2010 and December 31, 2009

Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the six months ended June 30, 2010 and June 30, 2009

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Consolidated Statements of Changes in Members Equity and Comprehensive Income Constellation Energy Partners LLC for the six months ended June 30, 2010

Notes to Consolidated Financial Statements

EXHIBIT INDEX

Exhibit Number	**Description**
*31.1.	Certification of Chief Executive Officer, Chief Operating Officer and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2.	Certification of 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

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SIGNATURES

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

CONSTELLATION ENERGY PARTNERS LLC
(REGISTRANT)

Date: August 6, 2010

By /s/ MICHAEL B. HINEY
Michael B. Hiney

Chief Accounting Officer and Controller

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