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 September 30, 2013

OR

o **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: 001-35344

LRR Energy, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**90-0708431** (I.R.S. Employer Identification No.)
Heritage Plaza **1111 Bagby, Suite 4600** **Houston, Texas** (Address of principal executive offices)	**77002** (Zip code)

Telephone Number: (713) 292-9510

(Registrant s telephone number, including area code)

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 o

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 and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

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

There were 19,448,539 Common Units, 6,720,000 Subordinated Units and 22,400 General Partner Units outstanding as of November 1, 2013. The Common Units trade on the New York Stock Exchange under the ticker symbol LRE .

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LRR Energy, L.P.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements.

LRR Energy, L.P.

Consolidated Condensed Balance Sheets

(Unaudited)

(in thousands, except unit amounts)

	September 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,301	$ 3,467
Accounts receivable	10,567	7,250
Commodity derivative instruments	11,635	16,484
Due from affiliates	2,293	
Prepaid expenses	978	748
Total current assets	30,774	27,949
Property and equipment (successful efforts method)	868,191	840,736
Accumulated depletion, depreciation and impairment	(354,527)	(324,774)
Total property and equipment, net	513,664	515,962
Commodity derivative instruments	17,491	20,000
Deferred financing costs, net of accumulated amortization	1,245	1,559
TOTAL ASSETS	$ 563,174	$ 565,470
LIABILITIES AND UNITHOLDERS EQUITY		
Current liabilities:		
Accrued liabilities	$ 5,039	$ 1,415
Accrued capital cost	5,253	2,361
Due to affiliates		1,977
Commodity derivative instruments	2,807	1,671
Interest rate derivative instruments	650	659
Asset retirement obligations	333	500
Total current liabilities	14,082	8,583
Long-term liabilities:		
Commodity derivative instruments	147	874
Interest rate derivative instruments	1,629	3,526
Term loan	50,000	50,000
Revolving credit facility	195,000	178,000
Asset retirement obligations	35,248	33,591
Deferred tax liabilities	114	120
Total long-term liabilities	282,138	266,111
Total liabilities	296,220	274,694
Unitholders equity:		
Predecessor s capital		60,941
	376	396

General partner (22,400 units issued and outstanding as of September 30, 2013 and December 31, 2012)				
Public common unitholders (17,598,939 units issued and outstanding as of September 30, 2013 and 10,676,742 units issued and outstanding as of December 31, 2012)		231,482		169,919
Affiliated common unitholders (1,849,600 units issued and outstanding as of September 30, 2013 and 5,049,600 units issued and outstanding as of December 31, 2012)		7,355		25,563
Subordinated unitholders (6,720,000 units issued and outstanding as of September 30, 2013 and December 31, 2012)		27,741		33,957
Total unitholders equity		266,954		290,776
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$	563,174	$	565,470

See accompanying notes to the unaudited consolidated condensed financial statements.

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LRR Energy, L.P.

Consolidated Condensed Statements of Operations

(Unaudited)

(in thousands, except per unit amounts)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Revenues:				
Oil sales	$ 22,239	$ 19,381	$ 56,714	$ 56,569
Natural gas sales	6,564	6,158	20,364	16,968
Natural gas liquids sales	2,655	2,783	7,165	8,969
Gain (loss) on commodity derivative instruments, net	(6,282)	(16,458)	5	7,975
Other income	19	30	106	33
Total revenues	25,195	11,894	84,354	90,514
Operating expenses:				
Lease operating expense	6,005	7,597	18,072	22,668
Production and ad valorem taxes	2,434	2,150	6,478	5,950
Depletion and depreciation	9,533	9,525	29,772	32,152
Impairment of oil and natural gas properties		451		3,544
Accretion expense	486	397	1,433	1,171
Loss (gain) on settlement of asset retirement obligations	(1)	94	334	(14)
General and administrative expense	2,669	2,580	8,866	9,325
Total operating expenses	21,126	22,794	64,955	74,796
Operating income (loss)	4,069	(10,900)	19,399	15,718
Other income (expense), net				
Interest expense	(2,349)	(2,081)	(6,863)	(4,541)
Gain (loss) on interest rate derivative instruments, net	(1,401)	(2,278)	1,371	(4,466)
Other income (expense), net	(3,750)	(4,359)	(5,492)	(9,007)
Income (loss) before taxes	319	(15,259)	13,907	6,711
Income tax expense	(35)	(20)	(102)	(170)
Net income (loss)	$ 284	$ (15,279)	$ 13,805	$ 6,541
Net income attributable to predecessor operations		(279)	(448)	(6,045)
Net income (loss) available to unitholders	$ 284	$ (15,558)	$ 13,357	$ 496
Computation of net income (loss) per limited partner unit:				
General partners interest in net income (loss)	$	$ (16)	$ 13	$
Limited partners interest in net income (loss)	$ 284	$ (15,542)	$ 13,344	$ 496
	$ 0.01	$ (0.69)	$ 0.53	$ 0.02

Net income (loss) per limited partner unit (basic and diluted)				
Weighted average number of limited partner units outstanding	26,169	22,428	25,098	22,426

See accompanying notes to the unaudited consolidated condensed financial statements.

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LRR Energy, L.P.

Consolidated Condensed Statement of Changes in Unitholders Equity

(Unaudited)

(in thousands)

				Limited Partners		
	Predecessor s Capital	General Partner	Public Common	Affiliated Common	Affiliated Subordinated	Total
Balance, December 31, 2012	$ 60,941	$ 396	$ 169,919	$ 25,563	$ 33,957	$ 290,776
Contribution to Lime Rock Resources	(734)		(445)	337	91	(751)
Book value of transferred properties contributed by Lime Rock Resources	(60,655)					(60,655)
Equity offering, net of expenses			59,513			59,513
Equity offering by limited partners			15,281	(15,281)		
Amortization of equity awards			391			391
Distribution		(33)	(22,153)	(4,213)	(9,726)	(36,125)
Net income	448	13	8,976	949	3,419	13,805
Balance, September 30, 2013	$	$ 376	$ 231,482	$ 7,355	$ 27,741	$ 266,954

See accompanying notes to the unaudited consolidated condensed financial statements.

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LRR Energy, L.P.

Consolidated Condensed Statements of Cash Flows

(Unaudited)

(in thousands)

	Nine Months Ended September 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 13,805	$ 6,541
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion and depreciation	29,772	32,152
Impairment of oil and natural gas properties		3,544
Accretion expense	1,433	1,171
Amortization of equity awards	391	231
Amortization of derivative contracts	746	7
Amortization of deferred financing costs and other	290	262
Loss (gain) on settlement of asset retirement obligations	334	(14)
Purchase of derivative contracts		(59)
Changes in operating assets and liabilities:		
Change in receivables	(3,317)	4,891
Change in prepaid expenses	(230)	58
Change in derivative assets and liabilities	5,137	14,072
Change in accrued liabilities and deferred tax liabilities	3,618	(2,245)
Change in amounts due to/from affiliates	(4,270)	(3,001)
Net cash provided by operating activities	47,709	57,610
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of oil and natural gas properties		(8,035)
Development of oil and natural gas properties	(24,857)	(26,905)
Expenditures for other property and equipment		(16)
Net cash used in investing activities	(24,857)	(34,956)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings under revolving credit facility	45,000	77,200
Principal payments on revolving credit facility	(28,000)	(50,000)
Borrowings under term loan		50,000
Equity offering, net of expenses	59,513	
Deferred financing costs		(561)
Distribution to Lime Rock Resources	(60,672)	(64,038)
Contribution to Lime Rock Resources	(734)	(3,925)
Distributions	(36,125)	(26,542)
Net cash used in financing activities	(21,018)	(17,866)
NET INCREASE IN CASH AND CASH EQUIVALENTS	1,834	4,788
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	3,467	1,513
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 5,301	$ 6,301
Supplemental disclosure of non-cash items to reconcile investing and financing activities		

Property and equipment:				
Change in accrued capital costs	$	2,892	$	(960)
Asset retirement obligations		(417)		(257)

See accompanying notes to the unaudited consolidated condensed financial statements.

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LRR Energy, L.P.

Notes to Consolidated Condensed Financial Statements

(unaudited)

1. Description of Business

LRR Energy, L.P. (we, us, our, or the Partnership) is a Delaware limited partnership formed in April 2011 by Lime Rock Management LP (Li Rock Management), an affiliate of Lime Rock Resources A, L.P. (LRR A), Lime Rock Resources B, L.P. (LRR B) and Lime Rock Resources C, L.P. (LRR C), to operate, acquire, exploit and develop producing oil and natural gas properties in North America with long-lived, predictable production profiles. As used herein, references to Fund I refer collectively to LRR A, LRR B and LRR C; references to Fund II refer collectively to Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P; and references to Fund III refer collectively to Lime Rock Resources III-A, L.P. and Lime Rock Resources III-C, L.P. References to Lime Rock Resources refer collectively to Fund I, Fund II and Fund III. Our properties are located in the Permian Basin region in West Texas and southeast New Mexico, the Mid-Continent region in Oklahoma and East Texas and the Gulf Coast region in Texas. We conduct our operations through our wholly owned subsidiary, LRE Operating, LLC (OLLC).

We own 100% of LRE Finance Corporation (LRE Finance). LRE Finance was organized for the purpose of co-issuing our debt securities and has no material assets or liabilities other than as co-issuer of our debt securities, if and when issued. Its activities are limited to co-issuing our debt securities and engaging in activities related thereto.

2. Summary of Significant Accounting Policies

As noted in Note 3, we are required to revise our historical financial statements to include results attributable to acquisitions from entities under common control. On August 28, 2013, we revised certain financial information included in our Annual Report on Form 10-K for the year ended December 31, 2012. References to our 2012 Annual Report incorporate both information included in the Annual Report on Form 10-K for the year ended December 31, 2012 and the Current Report on Form 8-K filed on August 28, 2013. Our accounting policies are set forth in Note 2 of the audited consolidated/combined financial statements in our 2012 Annual Report and are supplemented by the notes to these unaudited consolidated condensed financial statements. There have been no significant changes to these policies, and these unaudited consolidated condensed financial statements should be read in conjunction with the audited consolidated/combined financial statements and notes in our 2012 Annual Report.

Basis of presentation

These interim financial statements are unaudited and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) regarding interim financial reporting. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America (GAAP) for complete consolidated financial statements and should be read in conjunction with the audited consolidated/combined financial statements in our 2012 Annual Report. While the year-end balance sheet data was derived from audited financial statements, this interim report does not include all disclosures required by GAAP for annual periods. These unaudited interim consolidated condensed financial statements reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for the periods presented.

Certain reclassifications were made to the historical financial statements to conform to the 2013 presentation. The effects of the reclassification were not material to our unaudited interim consolidated condensed financial statements.

The Partnership s historical financial statements previously filed with the SEC have been revised in this quarterly report on Form 10-Q to include the results attributable to the acquisitions described in Note 3 and other acquisitions completed in 2012 that we considered to be between entities under common control.

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Recent accounting pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-11, Disclosures about Offsetting Assets and Liabilities. ASU No. 2011-11 required entities to disclose both gross information and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The objective of the disclosure is to facilitate comparison between those entities that prepare their financial statements on the basis of GAAP and those entities that prepare their financial statements on the basis of International Financial Reporting Standards. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which clarified the scope of these disclosures to include bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. We adopted this guidance effective January 1, 2013. This guidance did not have a material impact on our consolidated financial position, results of operations or cash flows.

3. Acquisitions

Acquisition between Entities under Common Control

On January 3, 2013, we completed an acquisition from Fund I of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma for a purchase price of $21.0 million, subject to customary purchase price adjustments (the January 2013 Acquisition). In addition, as part of the January 2013 Acquisition, we acquired in the money commodity hedge contracts valued at approximately $1.7 million as of the closing of the January 2013 Acquisition. The January 2013 Acquisition was effective October 1, 2012. In June 2013, we paid $0.4 million in cash to Fund I related to post-closing adjustments to the purchase price. We funded the January 2013 Acquisition with borrowings under our revolving credit facility (Note 7).

The following table presents the net assets conveyed by Fund I to us in the January 2013 Acquisition (in thousands):

Property and equipment, net	$	23,998
Oil and natural gas commodity hedge contracts		1,742
Asset retirement obligations and other liabilities		(1,067)
Net assets	$	24,673

On April 1, 2013, we completed an acquisition of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma and crude oil hedges from Fund II for a purchase price of $38.2 million (the April 2013 Acquisition). As part of the April 2013 Acquisition, we acquired in the money crude oil hedges valued at approximately $0.4 million as of the closing of the April 2013 Acquisition. The April 2013 Acquisition was effective April 1, 2013. We funded the April 2013 Acquisition with proceeds from our equity offering described in Note 10.

The following table presents the net assets conveyed by Fund II to us in the April 2013 Acquisition (in thousands):

Property and equipment, net	$	36,586
Oil and natural gas commodity hedge contracts		386
Asset retirement obligations and other liabilities		(990)
Net assets	$	35,982

The net assets of the January 2013 Acquisition and April 2013 Acquisition were recorded using carryover book value of Fund I and Fund II, respectively, as the acquisitions were deemed transactions between entities under common control. Our historical financial statements were revised to include the results attributable to previous acquisitions from Fund I and Fund II as if we owned the properties for all periods presented in our consolidated condensed financial statements.

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4. Fair Value Measurements

Our financial instruments, including cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. All such financial instruments are considered Level 1 instruments. The carrying value of our senior secured revolving credit facility and term loan, including the current portion, approximates fair value, as interest rates are variable based on prevailing market rates and are therefore considered Level 1 instruments. Our financial and non-financial assets and liabilities that are measured on a recurring basis are measured and reported at fair value.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of fair value hierarchy are as follows:

Level 1 Defined as inputs such as unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 Defined as inputs other than quoted prices in active markets that are either directly or indirectly observable for the asset or liability.

Level 3 Defined as unobservable inputs for use when little or no market data exists, requiring an entity to develop its own assumptions for the asset or liability.

We utilize the most observable inputs available for the valuation technique used. The financial assets and liabilities are classified in their entirety based on the lowest level of input that is of significance to the fair value measurement. The following table describes, by level within the hierarchy, the fair value of our financial assets and liabilities that were accounted for at fair value on a recurring basis (in thousands).

	Level 1	Level 2	Level 3	Total
September 30, 2013				
Assets:				
Commodity derivative instruments	$	$ 29,126	$	$ 29,126
Liabilities:				
Commodity derivative instruments		2,954		2,954
Interest rate derivative instruments		2,279		2,279
December 31, 2012				
Assets:				
Commodity derivative instruments	$	$ 36,484	$	$ 36,484
Liabilities:				
Commodity derivative instruments		2,545		2,545
Interest rate derivative instruments		4,185		4,185

All fair values reflected in the table above and on the consolidated condensed balance sheets have been adjusted for non-performance risk. The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Commodity Derivative Instruments The fair value of the commodity derivative instruments is estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services reflecting broker market quotes.

Interest Rate Derivative Instruments The fair value of the interest rate derivative instruments is estimated using a combined income and market valuation methodology based upon forward interest rates and volatility curves.

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The curves are obtained from independent pricing services reflecting broker market quotes.

5. Property and Equipment

The following table sets forth the components of property and equipment, net (in thousands):

		September 30, 2013		December 31, 2012
Oil and natural gas properties (successful efforts method)	$	866,643	$	839,154
Unproved properties		1,258		1,264
Other property and equipment		290		318
		868,191		840,736
Accumulated depletion, depreciation and impairment		(354,527)		(324,774)
Total property and equipment, net	$	513,664	$	515,962

We recorded $9.5 million of depletion and depreciation expense for each of the three months ended September 30, 2013 and 2012. We recorded $29.8 million and $32.2 million of depletion and depreciation expense for the nine months ended September 30, 2013 and 2012, respectively.

We perform an impairment analysis of our oil and natural gas properties on a quarterly basis due to the volatility in commodity prices. We did not record any impairment charges in the three or nine months ended September 30, 2013. For the three and nine months ended September 30, 2012, we recorded non-cash impairment charges of approximately $0.5 million and $3.5 million, respectively, to impair the value of our unproved properties and proved oil and natural gas properties in the Mid-Continent region. These non-cash charges are included in the Impairment of oil and natural gas properties line item in the consolidated condensed statements of operations.

This impairment of proved oil and natural gas properties was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in an internal reserve report. These reports are based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials. These are classified as Level 3 measurements. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in our estimated cash flows are the product of a process that begins with New York Mercantile Exchange (NYMEX) forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Furthermore, significant assumptions in valuing the proved reserves included the reserve quantities, anticipated drilling and operating costs, anticipated production taxes, future expected natural gas prices and basis differentials, anticipated drilling schedules, anticipated production declines, and an appropriate discount rate commensurate with the risk of the underlying cash flow estimates. Cash flow estimates for the impairment testing excluded derivative instruments used to mitigate the risk of lower future natural gas prices. Significant assumptions in valuing the unproved reserves included the evaluation of the probable and possible reserves included in the reserve reports, future expected oil and natural gas prices and basis differentials, and anticipated drilling schedules.

This asset impairment had no impact on cash flows, liquidity positions, or debt covenants. If future oil or natural gas prices decline further, the estimated undiscounted future cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for our properties and a non-cash impairment charge may be required to be recognized in future periods.

6. Asset Retirement Obligations

The following is a summary of our asset retirement obligations as of and for the nine months ended September 30, 2013 (in thousands):

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Beginning of period	$	34,091
Revisions to previous estimates		
Liabilities incurred		417
Liabilities settled		(360)
Accretion expense		1,433
End of period		35,581
Less: Current portion of asset retirement obligations		(333)
Asset retirement obligations non-current	$	35,248

7. Long-Term Debt

Credit Agreement

In July 2011, subject to consummation of our initial public offering, we, as guarantor, and our wholly owned subsidiary, OLLC, as borrower, entered into a five-year, $500 million senior secured revolving credit facility, as amended (the Credit Agreement), that matures in July 2016. The Credit Agreement is reserve-based and we are permitted to borrow under our credit facility an amount up to the borrowing base, which was $250 million as of September 30, 2013. Our borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders and once during the interim periods at their sole discretion. As of September 30, 2013, we were in compliance with all covenants contained in the Credit Agreement.

In November 2013, we expect our borrowing base to be reviewed by our lending group. We do not expect any material changes to our borrowing base.

Term Loan Agreement

On June 28, 2012, we, as parent guarantor, and our wholly owned subsidiary, OLLC, as borrower, entered into a Second Lien Credit Agreement (the Term Loan Agreement). The Term Loan Agreement provides for a $50 million senior secured second lien term loan to OLLC. OLLC borrowed $50 million under the Term Loan Agreement and used the borrowings to repay outstanding borrowings under the Credit Agreement. As of September 30, 2013, we were in compliance with all covenants contained in the Term Loan Agreement.

The obligations under the Term Loan Agreement and the Credit Agreement are governed by an Intercreditor Agreement with OLLC as borrower and the Partnership as parent guarantor, which (i) provides that any liens on the assets and properties of OLLC, the Partnership or any of their subsidiaries securing the indebtedness under the Term Loan Agreement are subordinate to liens on the assets and properties of OLLC, the Partnership or any of their subsidiaries securing indebtedness under the Credit Agreement and derivative contracts with lenders and their affiliates and (ii) sets forth the respective rights, obligations and remedies of the lenders under the Credit Agreement with respect to their first-priority liens and the lenders under the Term Loan Agreement with respect to their second-priority liens.

As of September 30, 2013, we had approximately $245.0 million of outstanding debt and accrued interest was approximately $0.3 million. As of December 31, 2012, we had approximately $228.0 million of outstanding debt and accrued interest was approximately $0.2 million.

Interest expense for the three months ended September 30, 2013 and 2012 was $2.3 million and $2.1 million, respectively. Interest expense for the nine months ended September 30, 2013 and 2012 was $6.9 million and $4.5 million, respectively. As of September 30, 2013 and December 31, 2012, our weighted average interest rate on our outstanding indebtedness was 3.60% and 3.47%, respectively. Please refer to Note 8 below for a discussion of our interest rate derivative contracts.

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8. Derivatives

Objective and strategy

We are exposed to commodity price and interest rate risk and consider it prudent to periodically reduce our exposure to cash flow variability resulting from commodity price changes and interest rate fluctuations. Accordingly, we enter into derivative instruments to manage our exposure to commodity price fluctuations, locational differences between a published index and the NYMEX futures on natural gas or crude oil productions, and interest rate fluctuations.

Our open positions typically consist of contracts such as (i) crude oil and natural gas financial collar contracts, (ii) crude oil, natural gas liquids (NGLs) and natural gas financial swaps, (iii) crude oil and natural gas basis financial swaps, (iv) crude oil and natural gas puts and (v) interest rate swap agreements. Our derivative instruments are with the counterparties that are also lenders in our Credit Agreement.

Swaps and options are used to manage our exposure to commodity price risk and basis risk inherent in our oil and natural gas production. Commodity price swap agreements are used to fix the price of expected future oil and natural gas sales at major industry trading locations such as Henry Hub Louisiana (HH) for gas and Cushing Oklahoma (WTI) for oil. Basis swaps are used to fix the price differential between the product price at one location versus another. Options are used to establish a floor and a ceiling price (collar) for expected oil or gas sales. Interest rate swaps are used to fix interest rates on existing indebtedness.

Under commodity swap agreements, we exchange a stream of payments over time according to specified terms with another counterparty. Specifically for commodity price swap agreements, we agree to pay an adjustable or floating price tied to an agreed upon index for the commodity, either gas or oil, and in return receive a fixed price based on notional quantities. Under basis swap agreements, we agree to pay an adjustable or floating price tied to two agreed upon indices for gas and in return receive the differential between a floating index and fixed price based on notional quantities. A collar is a combination of a put purchased by us and a call option written by us. In a typical collar transaction, if the floating price based on a market index is below the floor price, we receive from the counterparty an amount equal to this difference multiplied by the specified volume, effectively a put option. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty an amount equal to the difference multiplied by the specific quantity, effectively a call option.

The interest rate swap agreements effectively fix our interest rate on amounts borrowed under the credit facility. The purpose of these instruments is to mitigate our existing exposure to unfavorable interest rate changes. Under interest rate swap agreements, we pay a fixed interest rate payment on a notional amount in exchange for receiving a floating amount based on LIBOR on the same notional amount.

We elected not to designate any positions as cash flow hedges for accounting purposes and, accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in the consolidated condensed statements of operations. We record our derivative activities on a mark-to-market or fair value basis. Fair values are based on pricing models that consider various assumptions, including quoted forward prices for commodities, the time value of money and volatility, and are comparable to values obtained from counterparties. Pursuant to the accounting standard that permits netting of assets, liabilities, and collateral where the right of offset exists, we present the fair value of derivative financial instruments on a net basis in the consolidated condensed balance sheets.

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At September 30, 2013, we had the following open commodity derivative contracts:

	Index	2013	2014	2015	2016	2017
Natural gas positions						
Price swaps (MMBTUs)	NYMEX-HH	1,889,315	6,077,016	5,500,236	5,433,888	5,045,760
Weighted average price		$ 5.13	$ 5.53	$ 5.72	$ 4.29	$ 4.61
Basis swaps (MMBTUs)	NYMEX	1,861,575	5,876,098	5,326,559	2,877,047	
Weighted average price		$ (0.1365)	$ (0.1521)	$ (0.1661)	$ (0.1115)	$
Puts (MMBTUs)	NYMEX-HH	29,265				
Strike price		$ 3.00	$	$	$	$
Oil positions						
Price swaps (BBLs)	NYMEX-WTI	189,210	673,994	420,381	397,488	198,744
Weighted average price		$ 95.76	$ 95.85	$ 94.72	$ 86.02	$ 85.75
Basis swaps (BBLs)	Argus-	116,090	410,400			
Weighted average price	Midland-Cushing	$ (1.25)	$ (1.00)	$	$	$
NGL positions						
Price swaps (BBLs)	Mont Belvieu	52,829	183,857			
Weighted average price		$ 42.00	$ 34.11	$	$	$

At December 31, 2012, we had the following open commodity derivative contracts:

	Index	2013	2014	2015	2016	2017
Natural gas positions						
Price swaps (MMBTUs)	NYMEX-HH	7,516,540	6,077,016	5,500,236	4,878,990	4,605,396
Weighted average price		$ 5.16	$ 5.53	$ 5.72	$ 4.28	$ 4.61
Basis swaps (MMBTUs)	NYMEX	7,446,301	5,876,098	5,326,559	2,877,047	
Weighted average price		$ (0.1361)	$ (0.1521)	$ (0.1661)	$ (0.1115)	$
Puts (MMBTUs)	NYMEX-HH	178,710				
Strike price		$ 3.00	$	$	$	$
Oil positions						
Price swaps (BBLs)	NYMEX-WTI	698,816	519,102	420,381	397,488	198,744
Weighted average price		$ 95.95	$ 96.61	$ 94.72	$ 86.02	$ 85.75
NGL positions						
Price swaps (BBLs)	Mont Belvieu	144,323				
Weighted average price		$ 50.49	$	$	$	$

At September 30, 2013 and December 31, 2012, we had the following interest rate swap derivative contracts (in thousands):

Effective	Maturity		Notional Amount	Average %	Index
February 2012	February 2015	$	150,000	0.5175%	LIBOR
February 2015	February 2017		75,000	1.7250%	LIBOR
February 2015	February 2017		75,000	1.7275%	LIBOR
June 2012	June 2015		70,000	0.52375%	LIBOR
June 2015	June 2017		70,000	1.4275%	LIBOR

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Effect of Derivative Instruments Balance Sheet

The fair value of our commodity and interest rate derivative instruments is included in the tables below (in thousands):

	As of September 30, 2013			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$ 502	$ 650	$ 2,131
Gross fair value		502	650	2,131
Netting arrangements		(502)		(502)
Net recorded fair value	$	$	$ 650	$ 1,629
Sale of natural gas production				
Price swaps	$ 10,591	$ 13,472	$ 44	$ 105
Basis swaps	12	116	222	125
Sale of crude oil production				
Price swaps	1,032	4,569	2,390	491
Basis swaps			305	68
Sale of NGLs				
Price swaps	437	37	283	61
Gross fair value	12,072	18,194	3,244	850
Netting arrangements	(437)	(703)	(437)	(703)
Net recorded fair value	$ 11,635	$ 17,491	$ 2,807	$ 147

	As of December 31, 2012			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$ 13	$ 659	$ 3,539
Gross fair value		13	659	3,539
Netting arrangements		(13)		(13)
Net recorded fair value	$	$	$ 659	$ 3,526
Sale of natural gas production				
Price swaps	$ 12,185	$ 17,460	$ 155	$ 1,073
Basis swaps	18	27	317	470
Sale of crude oil production				
Price swaps	3,949	5,248	2,061	2,066
Sale of NGLs				
Price swaps	1,209		15	
Gross fair value	17,361	22,735	2,548	3,609
Netting arrangements	(877)	(2,735)	(877)	(2,735)
Net recorded fair value	$ 16,484	$ 20,000	$ 1,671	$ 874

Effect of Derivative Instruments Statement of Operations

The net gain or (loss) amounts and classification related to derivative instruments are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Commodity derivatives (revenue)	$ (6,282)	$ (16,458)	$ 5	$ 7,975
Interest rate derivatives (other income/expense)	(1,401)	(2,278)	1,371	(4,466)

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Credit Risk

All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative instruments involves the risk that the counterparties may be unable to meet the financial terms of the transactions. We monitor the creditworthiness of each of our counterparties and assess the possibility of whether each counterparty to the derivative contract would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. We also have netting arrangements in place with each counterparty to reduce credit exposure. The derivative transactions are placed with major financial institutions that present minimal credit risks to us. Additionally, we consider ourselves to be of substantial credit quality and have the financial resources and willingness to meet our potential repayment obligations associated with the derivative transactions.

9. Related Parties

Ownership of our General Partner by Lime Rock Management and its Affiliates

As of September 30, 2013, Lime Rock Management, an affiliate of Fund I, owned all of the Class A member interests in our general partner, Fund I owned all of the Class B member interests in our general partner and Fund II owned all of the Class C member interests in our general partner. In addition, Fund I owned an aggregate of approximately 9.5% of our outstanding common units and all of our subordinated units, representing a 32.7% limited partner interest in us. As of September 30, 2013, our general partner owned an approximate 0.1% general partner interest in us, represented by 22,400 general partner units, and all of our incentive distribution rights.

As more fully described in our 2012 Annual Report, three separate one-third tranches of the subordinated units may convert on the first business day after the distribution to unitholders in respect of any quarter ending on or after December 31, 2012, December 31, 2013 and December 31, 2014, respectively, provided that an aggregate amount equal to the minimum quarterly distribution payable with respect to all units that would be payable on four, eight or twelve consecutive quarters, as applicable, has been earned and paid prior to the applicable date, in each case provided there are no arrearages in the minimum quarterly distribution on our common units at that time. We do not expect one third of the subordinated units to convert pursuant to the provisions of our partnership agreement following our distribution for the third quarter of 2013 that will be paid on November 14, 2013. Each quarter, we will determine whether the test for conversion of the subordinated units has been met until the subordinated units convert pursuant to the provisions of our partnership agreement.

Contracts with our General Partner and its Affiliates

We have entered into various agreements with our general partner and its affiliates. For each of the three months ended September 30, 2013 and 2012, we paid Lime Rock Management approximately $0.5 million, either directly or indirectly, related to these agreements. For the nine months ended September 30, 2013 and 2012, we paid Lime Rock Management approximately $1.0 million and $1.2 million, respectively, either directly or indirectly, related to these agreements.

In connection with the management of our business, Lime Rock Resources Operating Company, Inc. (ServCo), an affiliate of our general partner, provides services for invoicing and processing of payments to our vendors. Periodically, ServCo remits cash to us for the net working capital received on our behalf. Changes in the affiliates (payable)/receivable balances during the nine months ended September 30, 2013 are included below (in thousands):

	ServCo	Lime Rock Resources	Total
Balance as of December 31, 2012	$ (2,229)	$ 252	$ (1,977)
Expenditures	(67,185)	(412)	(67,597)
Cash paid for expenditures	66,649	406	67,055
Revenues and other	5,058	(246)	4,812
Balance as of September 30, 2013	$ 2,293	$ 0	$ 2,293

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Distributions of Available Cash to Our General Partner and Affiliates

We will generally make cash distributions to our unitholders and our general partner pro rata. As of September 30, 2013, our general partner and its affiliates held 1,849,600 of our common units, all of our subordinated units and 22,400 general partner units. During the nine months ended September 30, 2013 and 2012, we paid cash distributions of $36.1 million and $26.5 million, respectively, to all unitholders as of the respective record dates.

We announced our third quarter 2013 distribution on October 18, 2013 as discussed in Note 14.

10. Unitholders Equity

Equity Offering

On March 22, 2013, we closed a public equity offering of 3,700,000 common units representing limited partner interests in the Partnership at a price to the public of $16.84 per common unit, or $16.1664 per common unit after payment of the underwriting discount. We received net proceeds from the sale of 3,700,000 newly issued common units of approximately $59.5 million, after deducting underwriting discounts and commissions and offering expenses of approximately $0.3 million. We used the net proceeds of the offering to fund our April 2013 Acquisition discussed in Note 3 and repay borrowings outstanding on our Credit Agreement.

Fund I sold 3,200,000 common units in the equity offering at a price to the public of $16.84 per common unit, or $16.1664 per common unit after payment of the underwriting discount. We did not receive any proceeds from the sale of common units by Fund I; however, the equity balance of Fund I was adjusted for its reduced ownership interest in us.

Units Outstanding

As of September 30, 2013, we had 19,448,539 common units, 6,720,000 subordinated units and 22,400 general partner units outstanding. As of September 30, 2013, Fund I owned 1,849,600 common units and all of our subordinated units, representing a 32.7% limited partner interest in us.

11. Net Income (Loss) Per Limited Partner Unit

The following sets forth the calculation of net income (loss) per limited partner unit (in thousands, except per unit amounts):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
Net income (loss)	$	284	$	(15,279)	$	13,805	$	6,541
Net income attributable to predecessor operations				(279)		(448)		(6,045)
Net income (loss) available to unitholders		284		(15,558)		13,357		496
Less: General partner s approximate 0.1% interest in net income (loss)				16		(13)		
Limited partners interest in net income (loss)	$	284	$	(15,542)	$	13,344	$	496
Weighted average limited partner units outstanding:								
Common units		19,449		15,708		18,378		15,706
Subordinated units		6,720		6,720		6,720		6,720
Total		26,169		22,428		25,098		22,426
Net income (loss) per limited partner unit (basic and diluted)	$	0.01	$	(0.69)	$	0.53	$	0.02

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Our subordinated units and restricted unit awards are considered to be participating securities for purposes of calculating our net income (loss) per limited partner unit, and accordingly, are included in basic computation as such. Net income (loss) per limited partner unit is determined by dividing the net income (loss) available to the common unitholders, after deducting our general partner s approximate 0.1% interest in net income (loss), by the weighted average number of common units and subordinated units outstanding as of September 30, 2013 and 2012. The aggregate number of common units and subordinated units outstanding was 19,448,539 and 6,720,000, respectively, as of September 30, 2013. The aggregate number of common units and subordinated units outstanding was 15,708,474 and 6,720,000, respectively, as of September 30, 2012.

12. Equity-Based Compensation

On November 10, 2011, our general partner adopted a long-term incentive plan (2011 LTIP) for employees, consultants and directors of our general partner and its affiliates, including Lime Rock Management and ServCo, who perform services for us. The 2011 LTIP consists of unit options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, unit awards and other unit-based awards. The 2011 LTIP initially limits the number of units that may be delivered pursuant to vested awards to 1,500,000 common units. As of September 30, 2013, there were 1,409,061 units available for issuance under the 2011 LTIP. The 2011 LTIP is currently administered by our general partner s board of directors.

The fair value of restricted units is determined based on the fair market value of the units on the date of grant. The outstanding restricted units vest in equal amounts (subject to rounding) over a three-year period following the date of grant and are entitled to receive quarterly distributions during the vesting period.

A summary of the status of the non-vested restricted units as of September 30, 2013, is presented below:

	Number of Non-vested Restricted Units	**Weighted Average Grant-Date Fair Value**
Non-vested restricted units at December 31, 2012	54,584	
Granted	22,197	$ 17.12
Vested	(2,800)	20.89
Forfeited		
Non-vested restricted units at September 30, 2013	73,981	

As of September 30, 2013, there was approximately $0.9 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.9 years. A total of 16,958 restricted units granted under the 2011 LTIP have vested as of September 30, 2013.

13. Subsidiary Guarantors

We and LRE Finance, our 100 percent-owned subsidiary, filed a registration statement on Form S-3 with the SEC on August 28, 2013, and the SEC declared the registration statement effective on September 10, 2013. Securities that may be offered and sold include debt securities that are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933. LRE Finance may co-issue any debt securities issued by us pursuant to the registration statement. LRE Finance was formed solely for the purpose of co-issuing our debt securities and has no material assets or liabilities other than as co-issuer of our debt securities. OLLC, our 100 percent-owned subsidiary, may guarantee any debt securities issued by us and such guarantee will be full and unconditional, subject to customary release provisions. The guarantee will be released (i) automatically upon any sale, exchange or transfer of our equity interests in OLLC, (ii) automatically upon the liquidation and dissolution of OLLC, (iii) following delivery of notice to the trustee under the indenture related to the debt securities of the release of OLLC of its obligations under our revolving credit facility, and (iv) upon legal or covenant defeasance or other satisfaction of the obligations under the related debt securities. Other than LRE Finance, OLLC is our sole subsidiary, and thus, no other subsidiary will guarantee our debt securities.

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Furthermore, we have no assets or operations independent of OLLC, and there are no significant restrictions upon the ability of OLLC to distribute funds to us by dividend or loan. Finally, none of our assets or the assets of OLLC represent restricted net assets pursuant to Rule 4-08(e)(3) of Regulation S-X.

14. Subsequent Events

Unit Distribution

On October 18, 2013, we announced that the board of directors of our general partner declared a cash distribution for the third quarter of 2013 of $0.4875 per outstanding unit, or $1.95 on an annualized basis. The distribution will be paid on November 14, 2013 to all unitholders of record as of the close of business on October 31, 2013. The aggregate amount of the distribution will be approximately $12.8 million.

Commodity Hedges

Subsequent to September 30, 2013, we acquired the following commodity hedges:

	Index	2014	2015
Oil positions			
Price swaps (BBLs)	NYMEX-WTI	49,640	
Weighted average price		$ 94.50	$
NGL positions			
Price swaps (BBLs)	Mont Belvieu		147,823
Weighted average price		$	$ 34.50

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

Cautionary Note Regarding Forward-Looking Statements

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

- *business strategies;*
- *ability to replace the reserves we produce through drilling and property acquisitions;*
- *drilling locations;*
- *oil and natural gas reserves;*
- *technology;*
- *realized oil and natural gas prices;*
- *production volumes;*
- *lease operating expenses;*
- *general and administrative expenses;*
- *future operating results;*
- *cash flows and liquidity;*
- *availability of drilling and production equipment;*
- *general economic conditions;*
- *effectiveness of risk management activities; and*
- *plans, objectives, expectations and intentions.*

All statements, other than statements of historical fact, are forward-looking statements. These forward-looking statements can be identified by their use of terms and phrases such as may, predict, pursue, expect, estimate, project, plan, believe, intend, achievable, anticipate, target, continue, potential, should, could and similar terms and phrases. Although we believe that *the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties some of which are beyond our control. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the risk factors described in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2012 that describe factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:*

- *our ability to generate sufficient cash to pay the minimum quarterly distribution on our common units;*
- *our ability to replace the oil and natural gas reserves we produce;*
- *our substantial future capital expenditures, which may reduce our cash available for distribution and could materially affect our ability to make distributions on our common units;*
- *a decline in oil, natural gas or natural gas liquids (NGL) prices;*
- *the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production;*
- *the risk that our hedging strategy may be ineffective or may reduce our income;*
- *uncertainty inherent in estimating our reserves;*
- *the risks and uncertainties involved in developing and producing oil and natural gas;*
- *risks related to potential acquisitions, including our ability to make accretive acquisitions on economically acceptable terms or to integrate acquired properties;*
- *competition in the oil and natural gas industry;*
- *cash flows and liquidity;*
- *restrictions and financial covenants in our credit facility and term loan;*
- *the availability of pipelines, transportation and gathering systems and processing facilities owned by third parties;*
- *electronic, cyber, and physical security breaches;*
- *general economic conditions; and*

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• *legislation and governmental regulations, including climate change legislation and federal or state regulation of hydraulic fracturing.*

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document and speak only as of the date of this report. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Overview

LRR Energy, L.P. (we, us, our, or the Partnership) is a Delaware limited partnership formed in April 2011 by Lime Rock Management LP (Li Rock Management), an affiliate of Lime Rock Resources A, L.P. (LRR A), Lime Rock Resources B, L.P. (LRR B) and Lime Rock Resources C, L.P. (LRR C), to operate, acquire, exploit and develop producing oil and natural gas properties in North America with long-lived, predictable production profiles. LRR A, LRR B and LRR C were formed by Lime Rock Management in July 2005 for the purpose of acquiring mature, low-risk producing oil and natural gas properties with long-lived production profiles. As used herein, references to Fund I refer collectively to LRR A, LRR B and LRR C; references to Fund II refer collectively to Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P; and references to Fund III refer collectively to Lime Rock Resources III-A, L.P. and Lime Rock Resources III-C, L.P. References to Lime Rock Resources refer collectively to Fund I, Fund II and Fund III.

Our properties are located in the Permian Basin region in West Texas and southeast New Mexico, the Mid-Continent region in Oklahoma and East Texas and the Gulf Coast region in Texas.

Contribution of Properties

On January 3, 2013, we completed an acquisition from Fund I of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma for a purchase price of $21.0 million, subject to customary purchase price adjustments (the January 2013 Acquisition). In addition, as part of the January 2013 Acquisition, we acquired in the money commodity hedge contracts valued at approximately $1.7 million at the closing of the January 2013 Acquisition. The January 2013 Acquisition was effective October 1, 2012. In June 2013, we paid $0.4 million in cash to Fund I related to post-closing adjustments to the purchase price.

On April 1, 2013, we completed an acquisition of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma and crude oil hedges from Fund II for a purchase price of $38.2 million (the April 2013 Acquisition). As part of the April 2013 Acquisition, we acquired in the money crude oil hedges valued at approximately $0.4 million as of the closing of the April 2013 Acquisition. The April 2013 Acquisition was effective April 1, 2013. We funded the April 2013 Acquisition with proceeds from our equity offering described in Note 10 to the consolidated condensed financial statements included in this report.

Results of Operations

The January 2013 Acquisition and April 2013 Acquisition were deemed to be transactions between entities under common control. As a result, our financial statements were revised to include the activities of such assets for all periods presented, similar to a pooling of interests, to include the financial position, results of operations and cash flows of the assets acquired and liabilities assumed. On August 28, 2013, we revised certain financial information included in our Annual Report on Form 10-K for the year ended December 31, 2012. References to our 2012 Annual Report incorporate both information included in the Annual Report on Form 10-K for the year ended December 31, 2012 and the Current Report on Form 8-K filed on August 28, 2013. The table set forth below includes recast historical financial and operating information attributable to previous acquisitions from Fund I and Fund II as if we owned the properties for all periods presented in our consolidated financial statements.

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	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Revenues (in thousands):				
Oil sales	$ 22,239	$ 19,381	$ 56,714	$ 56,569
Natural gas sales	6,564	6,158	20,364	16,968
Natural gas liquids sales	2,655	2,783	7,165	8,969
Gain (loss) on commodity derivative instruments, net	(6,282)	(16,458)	5	7,975
Other income	19	30	106	33
Total revenues	25,195	11,894	84,354	90,514
Expenses (in thousands):				
Lease operating expense	6,005	7,597	18,072	22,668
Production and ad valorem taxes	2,434	2,150	6,478	5,950
Depletion and depreciation	9,533	9,525	29,772	32,152
Impairment of oil and natural gas properties		451		3,544
General and administrative expense	2,669	2,580	8,866	9,325
Interest expense	2,349	2,081	6,863	4,541
(Gain) loss on interest rate derivative instruments, net	1,401	2,278	(1,371)	4,466
Production:				
Oil (MBbls)	216	227	614	634
Natural gas (MMcf)	1,849	2,160	5,500	6,507
NGLs (MBbls)	84	89	229	232
Total (MBoe)	608	676	1,760	1,951
Average net production (Boe/d)	6,609	7,348	6,447	7,120
Average sales price:				
Oil (per Bbl)				
Sales price	$ 102.96	$ 85.38	$ 92.37	$ 89.23
Effect of settled commodity derivative instruments	(9.76)	4.68	(2.92)	3.37
Realized price	$ 93.20	$ 90.06	$ 89.45	$ 92.60
Natural gas (per Mcf)				
Sales price	$ 3.55	$ 2.85	$ 3.70	$ 2.61
Effect of settled commodity derivative instruments	1.40	1.92	1.40	2.25
Realized price	$ 4.95	$ 4.77	$ 5.10	$ 4.86
NGLs (per Bbl)				
Sales price	$ 31.61	$ 31.27	$ 31.29	$ 38.66
Effect of settled commodity derivative instruments	3.83	6.82	4.88	4.72
Realized price	$ 35.44	$ 38.09	$ 36.17	$ 43.38
Average unit cost per Boe:				
Lease operating expenses	$ 9.87	$ 11.24	$ 10.27	$ 11.62
Production and ad valorem taxes	4.00	3.18	3.68	3.05
Depletion and depreciation	15.67	14.09	16.92	16.48
General and administrative expenses	4.39	3.82	5.04	4.78

Our Results for the Three Months Ended September 30, 2013 Compared to the Three Months Ended September 30, 2012

We recorded net income of $0.3 million for the three months ended September 30, 2013 compared to net loss of $15.3 million during the three months ended September 30, 2012, primarily related to higher revenues and lower operating expenses. The following discussion summarizes key components of the changes between periods.

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Sales Revenues. A summary of increases (decreases) in our oil, natural gas and NGL revenues between the three months ended September 30, 2012 and September 30, 2013 follows (in thousands):

Oil, natural gas and NGL revenues-prior period	$	28,322
Increase (decrease)		
Price realization		
Oil		3,991
Natural gas		1,510
NGLs		30
Sales volumes		
Oil		(1,133)
Natural gas		(1,104)
NGLs		(158)
Oil, natural gas and NGL revenues-current period	$	31,458

Sales revenues increased from $28.3 million for the three months ended September 30, 2012 to $31.5 million for the three months ended September 30, 2013, primarily due to higher commodity price realizations offset by lower oil, natural gas and NGL sales volumes. Sales revenues for the three months ended September 30, 2013 consisted of oil sales of $22.2 million, natural gas sales of $6.6 million and NGL sales of $2.7 million. Sales revenues for the three months ended September 30, 2012 consisted of oil sales of $19.4 million, natural gas sales of $6.1 million and NGL sales of $2.8 million.

Our production volumes for the three months ended September 30, 2013 included 300 MBbls of oil and NGLs and 1,849 MMcf of natural gas, or 3,261 Bbl/d of oil and NGLs and 20,098 Mcf/d of natural gas. On an equivalent basis, production for the period was 608 MBoe, or 6,609 Boe/d. Our production volumes for the three months ended September 30, 2012 included 316 MBbls of oil and NGLs and 2,160 MMcf of natural gas, or 3,435 Bbl/d of oil and NGLs and 23,478 Mcf/d of natural gas. On an equivalent basis, production for the period was 676 MBoe, or 7,348 Boe/d.

Our average sales price per Bbl for oil and NGLs for the three months ended September 30, 2013, excluding the effect of commodity derivative contracts, was $102.96 and $31.61, respectively. Our average sales price per Mcf of natural gas for the three months ended September 30, 2013, excluding the effect of commodity derivative contracts, was $3.55. Our average sales price per Bbl for oil and NGLs for the three months ended September 30, 2012, excluding the effect of commodity derivative contracts, was $85.38 and $31.27, respectively. Our average sales price per Mcf of natural gas for the three months ended September 30, 2012, excluding the effect of commodity derivative contracts, was $2.85.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, we recorded a net loss from our commodity hedging program for the three months ended September 30, 2013 of approximately $6.3 million, which is comprised of positive settlements and amortization of purchases of approximately $0.8 million and declines in the fair value of derivatives of approximately $7.1 million. For the three months ended September 30, 2012, we recorded a net loss from our commodity hedging program of approximately $16.5 million, which is comprised of positive settlements and amortization of approximately $5.8 million and declines in fair value of derivatives of approximately $22.3 million. Volatility in commodity prices has had a significant impact on our gains and losses on commodity derivative contracts.

Lease Operating Expense. Our lease operating expenses were approximately $6.0 million, or $9.87 per Boe, for the three months ended September 30, 2013 compared to approximately $7.6 million, or $11.24 per Boe, for the three months ended September 30, 2012. The primary drivers of the decreased lease operating expenses were lower workover expenses and lower saltwater disposal costs.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $2.4 million, or $4.00 per Boe, for the three months ended September 30, 2013 compared to approximately $2.2 million, or $3.18 per Boe, for the three months ended September 30, 2012. Production taxes accounted for approximately $2.2 million and ad valorem taxes for $0.2 million of the total taxes recorded during the three months ended September 30, 2013. Production taxes accounted for approximately $2.0 million and ad valorem taxes for $0.2 million of the total taxes

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recorded during the three months ended September 30, 2012. The increase in per Boe amounts was primarily related to lower production volumes.

Depletion and Depreciation. Our depletion and depreciation expense was approximately $9.5 million, or $15.67 per Boe, for the three months ended September 30, 2013 compared to approximately $9.5 million, or $14.09 per Boe, for the three months ended September 30, 2012. The increase in per Boe amounts was primarily related to lower production volumes.

Impairment of Oil and Natural Gas Properties. We did not record an impairment charge in the three months ended September 30, 2013. We recorded an impairment of $0.5 million for the three months ended September 30, 2012 on our unproved properties during the period. If future oil or natural gas prices decline, the estimated undiscounted future cash flows for our proved oil and natural gas properties may not exceed the net capitalized costs for such properties and a non-cash impairment charge may be required to be recognized in future periods. As of November 1, 2013, the NYMEX-WTI oil spot price was $94.61 per Bbl and the NYMEX-Henry Hub natural gas spot price was $3.46 per MMBtu.

General and Administration Expenses. Our general and administrative expenses were approximately $2.7 million, or $4.39 per Boe, for the three months ended September 30, 2013 compared to approximately $2.6 million, or $3.82 per Boe, for the three months ended September 30, 2012. The increase in per Boe amounts was primarily due to lower production volumes.

Interest Expense. Our interest expense is comprised of interest on our credit facility and term loan and amortization of debt issuance costs. Interest expense was approximately $2.3 million and $2.1 million for the three months ended September 30, 2013 and 2012, respectively.

Effects of Interest Rate Derivatives. Losses on interest rate derivative contracts, net, was approximately $1.4 million for the three months ended September 30, 2013, including $0.2 million in negative settlements and $1.2 million in declines in fair value of the derivatives. Losses on interest rate derivative contracts, net, was approximately $2.3 million for the three months ended September 30, 2012, including $0.2 million in negative settlements and $2.1 million in declines in fair value of the derivatives.

Our Results for the Nine Months Ended September 30, 2013 Compared to the Nine Months Ended September 30, 2012

We recorded net income of $13.8 million for the nine months ended September 30, 2013 compared to net income of $6.5 million during the nine months ended September 30, 2012, primarily related to lower overall expenses. The following discussion summarizes key components of the changes between periods.

Sales Revenues. A summary of increases (decreases) in our oil, natural gas and NGL revenues between the nine months ended September 30, 2012 and September 30, 2013 follows (in thousands):

Oil, natural gas and NGL revenues-prior period	$	82,506
Increase (decrease)		
Price realization		
Oil		1,991
Natural gas		7,123
NGLs		(1,710)
Sales volumes		
Oil		(1,847)
Natural gas		(3,726)
NGLs		(94)
Oil, natural gas and NGL revenues-current period	$	84,243

Sales revenues increased from $82.5 million for the nine months ended September 30, 2012 to $84.2 million for the nine months ended September 30, 2013, primarily driven by higher natural gas price realizations offset by lower production. Sales revenues for the nine months ended September 30, 2013 consisted of oil sales of $56.7 million, natural gas sales of $20.3 million and NGL sales of $7.2 million. Sales revenues for the nine months ended September 30, 2012 consisted of oil sales of $56.5 million, natural gas sales of $17.0 million and NGL sales of $9.0 million.

Our production volumes for the nine months ended September 30, 2013 included 843 MBbls of oil and NGLs and 5,500 MMcf of natural gas, or 3,088 Bbl/d of oil and NGLs and 20,147 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,760 MBoe, or 6,447 Boe/d. Our production volumes for the nine months ended September 30, 2012 included 866 MBbls of oil and NGLs and 6,507 MMcf of natural gas, or 3,161 Bbl/d of oil and NGLs and 23,748 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,951 MBoe, or 7,120 Boe/d.

Our average daily production of 6,447 Boe/d for the nine months ended September 30, 2013 was negatively impacted by the following items which resulted in lower production of approximately 345 Boe/d. The actual timing and amount of resumed production related to the items below may differ from these estimates.

At our Red Lake field, our third party gas processor required us to flare approximately 90 Boe/d due to plant capacity constraints and compressor issues during the nine months ended September 30, 2013. We are currently flaring approximately 50 Boe/d due to third-party plant compression limits and we expect that we will continue to flare at this level until a new compressor station at the plant is put into service, which we expect will occur during the fourth quarter of 2013. Delays in our recompletion program at our Red Lake field during the first quarter resulted in lower production of approximately 14 Boe/d. The delayed projects were completed during the second quarter of 2013.

Production at our Putnam field experienced weather related shut-ins of approximately 22 Boe/d during the first quarter of 2013. The Putnam field resumed normal operations in the second quarter of 2013.

Our Pecos Slope field was curtailed by approximately 1.3 MMcf/d (211 Boe/d) during the nine months ended September 30, 2013 due to the previously disclosed high nitrogen content of our produced natural gas (1.0 MMcf/d or 167 Boe/d) and a compressor failure (0.3 MMcf/d or 44 Boe/d). The compressor resumed service on February 18, 2013. The current nitrogen content curtailment is approximately 1.2 MMcf/d (200 Boe/d) and we expect it to remain at this level until the field-wide nitrogen rejection facility is completed, which we expect will occur in the first quarter of 2014. A well at our New Years Ridge field had a tubing failure during the first quarter of 2013 resulting in curtailed production of approximately 49 Mcfe/d (8 Boe/d) during the nine months ended September 30, 2013. The well resumed service during the second quarter of 2013.

Our average sales price per Bbl for oil and NGLs for the nine months ended September 30, 2013, excluding the effect of commodity derivative contracts, was $92.37 and $31.29, respectively. Our average sales price per Mcf of natural gas for the nine months ended September 30, 2013, excluding the effect of commodity derivative contracts, was $3.70. Our average sales price per Bbl for oil and NGLs for the nine months ended September 30, 2012, excluding the effect of commodity derivative contracts, was $89.23 and $38.66, respectively. Our average sales price per Mcf of natural gas for the nine months ended September 30, 2012, excluding the effect of commodity derivative contracts, was $2.61.

In addition to lower realized production, our financial results for the nine months ended September 30, 2013 were impacted by a higher Midland to Cushing oil differential during the first quarter of 2013. The differential averaged $7.88 per barrel for the first quarter compared to the full year 2011 and 2012 average differential of $2.30 per barrel. We estimated the impact of the higher differential (compared to the 2011 and 2012 average differential) on revenue for the first quarter of 2013 was approximately $0.8 million. In February 2013, we executed Midland to Cushing oil basis swaps for March 2013 through December 2014 on the majority of our expected production that we expected to be impacted by the differential.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, we recorded a net gain from our commodity hedging program for the nine months ended September 30, 2013 of less than $0.1 million, which is comprised of a positive settlements and amortization of purchases of approximately $7.1 million and declines in fair value of derivatives of approximately $7.0 million. For the nine months ended September 30, 2012, we recorded a net gain from our commodity hedging program of approximately $8.0 million, which is comprised of

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positive settlements and amortization of approximately $17.9 million and declines in fair value of derivatives of approximately $9.9 million. Volatility in commodity prices has had a significant impact on our gains and losses on commodity derivative contracts.

Lease Operating Expense. Our lease operating expenses were approximately $18.1 million, or $10.27 per Boe, for the nine months ended September 30, 2013 compared to approximately $22.7 million, or $11.62 per Boe, for the nine months ended September 30, 2012. The primary drivers of the decreased lease operating expenses were lower workover expenses and lower saltwater disposal costs.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $6.5 million, or $3.68 per Boe, for the nine months ended September 30, 2013 compared to approximately $5.9 million, or $3.05 per Boe, for the nine months ended September 30, 2012. Production taxes accounted for approximately $5.9 million and ad valorem taxes for $0.6 million of the total taxes recorded during the nine months ended September 30, 2013. Production taxes accounted for approximately $5.4 million and ad valorem taxes for $0.5 million of the total taxes recorded during the nine months ended September 30, 2012.

Depletion and Depreciation. Our depletion and depreciation expense was approximately $29.8 million, or $16.92 per Boe, for the nine months ended September 30, 2013 compared to approximately $32.2 million, or $16.48 per Boe, for the nine months ended September 30, 2012. The decrease in the depreciation expense was primarily related to lower production volumes.

Impairment of Oil and Natural Gas Properties. We did not record an impairment charge in the nine months ended September 30, 2013. We recorded an impairment of approximately $3.5 million for the nine months ended September 30, 2012 on our proved properties during the period. If future oil or natural gas prices decline, the estimated undiscounted future cash flows for our proved oil and natural gas properties may not exceed the net capitalized costs for such properties and a non-cash impairment charge may be required to be recognized in future periods. As of November 1, 2013, the NYMEX-WTI oil spot price was $94.61 per Bbl and the NYMEX-Henry Hub natural gas spot price was $3.46 per MMBtu.

General and Administration Expenses. Our general and administrative expenses were approximately $8.9 million, or $5.04 per Boe, for the nine months ended September 30, 2013 compared to approximately $9.3 million, or $4.78 per Boe, for the nine months ended September 30, 2012. The increase in per Boe amounts was primarily due to lower production volumes.

Interest Expense. Our interest expense is comprised of interest on our credit facility and term loan and amortization of debt issuance costs. Interest expense was approximately $6.9 million and $4.5 million for the nine months ended September 30, 2013 and 2012, respectively. The increase in interest expense was primarily due to the increased debt level outstanding during the nine months ended September 30, 2013.

Effects of Interest Rate Derivatives. Gains on interest rate derivative contracts, net, was approximately $1.4 million for the nine months ended September 30, 2013, including $0.5 million in negative settlements and $1.9 million in positive fluctuations in fair value of derivatives. Losses on interest rate derivative contracts, net, was approximately $4.5 million for the nine months ended September 30, 2012, including $0.3 million in negative settlements and $4.2 million in declines in fair value of derivative instruments.

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Non-GAAP Financial Measures

Below we disclose the non-GAAP financial measures Adjusted EBITDA and Distributable Cash Flow for the periods presented and provide reconciliations of these items to net income, our most directly comparable financial performance measure calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income plus or minus:

- Income tax expense;
- Interest expense-net, including gains (losses) on interest rate derivative instruments, net;
- Depletion and depreciation;
- Accretion of asset retirement obligations;
- Amortization of equity awards;
- Gain (loss) on settlement of asset retirement obligations;
- Gain (loss) on commodity derivative instruments, net;
- Commodity derivative instrument settlements;
- Amortization of derivative contracts;
- Impairment of oil and natural gas properties; and
- Other non-recurring items that we deem appropriate.

We define Distributable Cash Flow as Adjusted EBITDA less cash income tax expense, cash interest expense and estimated maintenance capital expenditures.

Adjusted EBITDA and Distributable Cash Flow are used as supplemental financial measures by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess:

- our operating performance as compared to that of other companies and partnerships in our industry, without regard to financing methods, capital structure or historical cost basis; and
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders.

Our management believes that both Adjusted EBITDA and Distributable Cash Flow are useful to investors because these measures are used by many partnerships in the industry as measures of operating and financial performance and are commonly employed by financial analysts and others to evaluate the operating and financial performance of the Partnership from period to period and to compare it with the performance of other publicly traded partnerships within the industry. Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income, operating income, or any other measures of financial performance presented in accordance with GAAP. Our Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA and Distributable Cash Flow in the same manner.

Our Adjusted EBITDA for the three months ended September 30, 2013 and 2012 was approximately $21.5 million and $21.9 million, respectively. Our Adjusted EBITDA for the nine months ended September 30, 2013 and 2012 was approximately $59.1 million and $62.7 million, respectively.

Our Distributable Cash Flow for the three months ended September 30, 2013 and 2012 was approximately $14.0 million and $14.6 million, respectively. Our Distributable Cash Flow for the nine months ended September 30, 2013 and 2012 was approximately $36.7 million and $42.6 million, respectively.

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Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Income

The following table presents a reconciliation of Adjusted EBITDA and Distributable Cash Flow to net income, our most directly comparable GAAP financial performance measure, for each of the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Net income (loss)	$ 284	$ (15,279)	$ 13,805	$ 6,541
Income tax expense	35	20	102	170
Interest expense-net, including (gain) loss on interest rate derivative instruments	3,750	4,359	5,492	9,007
Depletion and depreciation	9,533	9,525	29,772	32,152
Accretion of asset retirement obligations	486	397	1,433	1,171
Amortization of equity awards	138	81	391	231
Loss (gain) on settlement of asset retirement obligations	(1)	94	334	(14)
Loss (gain) on commodity derivative instruments, net	6,282	16,458	(5)	(7,975)
Commodity derivative instrument settlements	801	5,808	7,049	17,876
Amortization of derivative contracts	238	6	746	7
Impairment of oil and natural gas properties		451		3,544
Adjusted EBITDA	$ 21,546	$ 21,920	$ 59,119	$ 62,710
Adjusted EBITDA	21,546	21,920	59,119	62,710
Cash income tax expense	(35)	(20)	(108)	(64)
Cash interest expense	(2,438)	(2,234)	(7,054)	(4,865)
Estimated maintenance capital (1)	(5,075)	(5,075)	(15,225)	(15,225)
Distributable Cash Flow	$ 13,998	$ 14,591	$ 36,732	$ 42,556

(1) Amount represents pro-rated capital for the period. Estimated maintenance capital expenditures as defined by our partnership agreement represent our estimate of the amount of capital required on average per year to maintain our production over the long term.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements depends on our ability to generate cash. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for oil and natural gas, weather and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

Our primary sources of liquidity and capital resources are cash flows generated by operating activities, borrowings under our credit facility and term loan and equity offerings. We may issue additional equity and debt as needed.

We enter into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 65% to 85% of our estimated production from total proved developed producing reserves over a three-to-five year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to our unitholders and our general partner. In making cash distributions, our general partner attempts to avoid large variations in the amount we distribute from quarter to quarter. In order to facilitate this, our partnership agreement permits our general partner to establish cash reserves to be used to pay distributions for any one or more of the next four quarters. In addition, our partnership agreement allows our general partner to borrow funds to make distributions.

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We may borrow to make distributions to our unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long-term, but short-term factors have caused available cash from operations to be insufficient to sustain our level of distributions. In addition, a significant portion of our production is hedged. We are generally required to settle our commodity hedge derivatives within five days of the end of the month. As is typical in the oil and gas industry, we generally do not receive the proceeds from the sale of our hedged production until 45 to 60 days following the end of the month. As a result, when commodity prices increase above the fixed price in the derivative contracts, we are required to pay the derivative counterparty the difference between the fixed price in the derivative contract and the market price before we receive the proceeds from the sale of the hedged production. If this occurs, we may make working capital borrowings to fund our distributions. Because we distribute all of our available cash, we will not have those amounts available to reinvest in our business to increase our proved reserves and production and as a result, we may not grow as quickly as other oil and gas entities or at all.

We are committed to reinvesting a sufficient amount of our cash flow to fund our exploitation and development capital expenditures in order to maintain our production, and we use, and intend to use in the future, primarily external financing sources, including commercial bank borrowings and the issuance of debt and equity interests, rather than cash reserves established by our general partner, to make acquisitions to further increase our production and proved reserves. Because our proved reserves and production decline continually over time and because we do not own any significant undeveloped properties or leasehold acreage, we will need to make acquisitions to sustain our level of distributions to unitholders over time.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures, reduce distributions to unitholders, and/or fund a portion of our capital expenditures using borrowings under our credit facility or term loan, issuances of debt and equity securities or from other sources, such as asset sales. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our credit facility and term loan. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

As of September 30, 2013, we had borrowing capacity of $55.0 million under our $500 million revolving credit facility ($250 million borrowing base less $195.0 million of outstanding borrowings) and $5.3 million of cash on hand. As of September 30, 2013, we had no available borrowing capacity under our $50 million term loan.

Based upon current oil and natural gas price expectations and our commodity derivatives positions for the period ended September 30, 2013, which cover 84% of our remaining 2013 estimated production from total proved developed producing reserves, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient working capital to meet our planned 2013 capital expenditure and minimum distribution requirements as described under Outlook below.

Credit Agreement

In July 2011, subject to consummation of our initial public offering, we, as guarantor, and our wholly owned subsidiary, LRE Operating, LLC (OLLC), as borrower, entered into a five-year, $500 million senior secured revolving credit facility, as amended (the Credit Agreement), that matures in July 2016. The Credit Agreement is reserve-based and we are permitted to borrow under our credit facility an amount up to the borrowing base, which was $250 million as of September 30, 2013. Our borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders and once during the interim periods at their sole discretion. In November 2013, we expect our borrowing base to be reviewed by our lending group. We do not expect any material changes to our borrowing base.

A future decline in commodity prices could result in a redetermination that lowers our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base, or we could be required to pledge other oil and natural gas properties as additional collateral. We do not anticipate having any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our credit facility. Additionally, we will not be able to pay

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distributions to our unitholders in any such quarter in the event there exists a borrowing base deficiency or an event of default either before or after giving effect to such distribution or we are not in pro forma compliance with the credit facility after giving effect to such distribution.

If we fail to perform our obligations under the covenants described in our 2012 Annual Report, the revolving credit commitments could be terminated and any outstanding indebtedness under the credit facility, together with accrued interest, could be declared immediately due and payable. As of September 30, 2013, we were in compliance with our covenants.

At September 30, 2013, we had approximately $195.0 million of outstanding borrowings under our credit facility and available borrowing capacity of approximately $55.0 million.

Term Loan Agreement

On June 28, 2012, we, as parent guarantor, and our wholly owned subsidiary, OLLC, as borrower, entered into a Second Lien Credit Agreement (the Term Loan Agreement). The Term Loan Agreement provides for a $50 million senior secured second lien term loan to OLLC. OLLC borrowed $50 million under the Term Loan Agreement and used the borrowings to repay outstanding borrowings under the Credit Agreement.

Our Term Loan Agreement contains various covenants and restrictive provisions as described in our 2012 Annual Report. As of September 30, 2013, we were in compliance with all covenants contained in the Term Loan Agreement.

Commodity Derivative Contracts

The following table summarizes, for the periods presented, the weighted average price and notional volumes of our oil, NGL and natural gas swaps and collars in place as of September 30, 2013. The weighted average price is based on the swap price for oil, NGL and natural gas swaps and the floor price of oil and natural gas collars. We use swaps and collars as a mechanism for managing commodity price risks whereby we pay the counterparty floating prices and receive fixed prices from the counterparty. By entering into the hedge agreements, we mitigate the effect on our cash flows of changes in the prices we receive for our oil, NGL and natural gas production.

	Oil (NYMEX-WTI) Weighted Average		NGL (Mount Belvieu) Weighted Average		Natural Gas (NYMEX-Henry Hub) Weighted Average	
Term	**$/Bbl**	**Bbls/d**	**$/Bbl**	**Bbls/d**	**$/Mmbtu**	**Mmbtu/d**
2013	$ 95.76	2,057	$ 42.00	574	$ 5.09	20,854
2014	$ 95.85	1,847	$ 34.11	504	$ 5.53	16,649
2015	$ 94.72	1,152	$		$ 5.72	15,069
2016	$ 86.02	1,089	$		$ 4.29	14,887
2017	$ 85.75	545	$		$ 4.61	13,824

The following table summarizes, for the periods presented, our natural gas basis swaps in place as of September 30, 2013. These contracts are designed to effectively fix a price differential between the NYMEX-Henry Hub price and the index price at which the physical natural gas is sold.

	Centerpoint East		Houston Ship Channel		WAHA		TEXOK	
Term	**$/Mmbtu**	**Mmbtu/d**	**$/Mmbtu**	**Mmbtu/d**	**$/Mmbtu**	**Mmbtu/d**	**$/Mmbtu**	**Mmbtu/d**
2013	$ (0.1872)	8,014	$ (0.0838)	4,499	$ (0.1172)	6,579	$ (0.0990)	1,142
2014	$ (0.2121)	6,459	$ (0.0835)	3,475	$ (0.1290)	5,245	$ (0.1220)	919
2015	$ (0.2291)	5,939	$ (0.0959)	3,031	$ (0.1380)	4,777	$ (0.1334)	846
2016	$		$ (0.0810)	2,691	$ (0.1326)	4,408	$ (0.0975)	784

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The following table summarizes, for the periods presented, our oil basis swaps in place as of September 30, 2013. These contracts are designed to effectively fix a price differential between the NYMEX-WTI price and the index price at which the physical oil is sold.

Term		Midland-Cushing $/Bbl	Bbl/d
2013	$	(1.2500)	1,262
2014	$	(1.0000)	1,124

Cash Flows

Cash flows provided (used) by type of activity were as follows for the periods indicated (in thousands):

	Nine Months Ended September 30, 2013		2012	
Net cash provided by (used in):				
Operating activities	$	47,709	$	57,610
Investing activities		(24,857)		(34,956)
Financing activities		(21,018)		(17,866)

Operating Activities.

Net cash provided by operating activities was approximately $47.7 million and $57.6 million for the nine months ended September 30, 2013 and 2012, respectively. Revenues fluctuate due to the volatility of commodity prices, and therefore our cash provided by operating activities is impacted by the prices received for oil and natural gas sales, as well as levels of production volumes and operating expenses.

Our working capital totaled $16.7 million and $19.4 million at September 30, 2013 and December 31, 2012, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $5.3 million and $3.5 million at September 30, 2013 and December 31, 2012, respectively.

Investing Activities.

Net cash used in investing activities was approximately $24.9 million and $35.0 million for the nine months ended September 30, 2013 and 2012, respectively, which primarily represented additions to our property and equipment balances during the period.

Financing Activities.

Net cash used in financing activities was approximately $21.0 million for the nine months ended September 30, 2013, and consisted of net proceeds received from an equity offering of approximately $59.5 million and net borrowings under the Credit Agreement of $17.0 million offset by contributions and distributions to Lime Rock Resources associated with acquisitions of $61.4 million and distributions to unitholders of $36.1 million.

Net cash used in financing activities was approximately $17.9 million for the nine months ended September 30, 2012, which included distributions paid to our unitholders of $26.5 million, contributions and distributions to Lime Rock Resources of $68.0 million and deferred financing costs of $0.6 million, offset by net borrowings of $77.2 million.

Outlook

We expect to spend approximately $34.0 million in total capital expenditures in 2013, of which approximately $20.3 million represents maintenance capital expenditures, on the development of our oil and natural gas properties.

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We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.4750 per unit per quarter ($1.90 per unit on an annualized basis). Based on the number of common units, subordinated units and general partner units outstanding as of November 1, 2013, quarterly distributions to all of our unitholders at the minimum quarterly distribution rate would total approximately $12.4 million. We recently announced an increase to our quarterly distribution for the third quarter of 2013. Our current distribution is $0.4875 per unit ($1.95 per unit on an annualized basis), or $12.8 million in aggregate. Our board of directors determines our distribution each quarter and there is no guarantee that the board will maintain or increase our current quarterly distribution in future periods.

We intend to pursue acquisitions of long-lived, low-risk producing oil and natural gas properties with reserve exploitation potential. We would expect to finance any significant acquisition of oil and natural gas properties in 2013 through external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities.

Off-Balance Sheet Arrangements

As of September 30, 2013, we had no off-balance sheet arrangements.

Critical Accounting Policies and Estimates

There have been no material changes to our critical accounting policies from those described in our 2012 Annual Report.

Recently Issued Accounting Pronouncements

Refer to Note 2 of the consolidated condensed financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes to the commodity price risk, interest rate risk and counterparty and customer credit risk discussed in our 2012 Annual Report under the caption Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosure About Market Risk.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act, as amended (the Exchange Act), we have evaluated, under the supervision and with the participation of our management, including our principal executive officers and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officers and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Our principal executive officers and principal financial officer, with the participation of management, have concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of September 30, 2013.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, neither we nor our general partner is currently a party to any material legal proceedings. In addition, we are not aware of any significant legal or governmental proceedings against us or our general partner, or contemplated to be brought against us or our general partner, under the various environmental protection statues to which we or our general partner is subject.

Item 1A. Risk Factors.

There have been no material changes to the risk factors described in our 2012 Annual Report.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

None.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of LRR Energy, L.P. dated as of April 28, 2011 (incorporated by reference to Exhibit 3.1 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.2	First Amended and Restated Agreement of Limited Partnership of LRR Energy, L.P. dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Annual Report on Form 10-K (SEC File No. 001-35344), filed on March 27, 2012).
3.3	Certificate of Formation of LRE GP, LLC dated as of April 28, 2011 (incorporated by reference to Exhibit 3.4 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of LRE GP, LLC dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
31.1*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.

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31.3*	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
32.1*	Certification by Co-Chief Executive Officers and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith

** Submitted electronically herewith

In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this Quarterly Report on Form 10-Q shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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SIGNATURES

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

	LRR Energy, L.P.	
	By:	**LRE GP, LLC,** its General Partner
Date: November 6, 2013	By:	/s/ Eric Mullins Eric Mullins Co-Chief Executive Officer
Date: November 6, 2013	By:	/s/ Jaime R. Casas Jaime R. Casas Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)

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EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Limited Partnership of LRR Energy, L.P. dated as of April 28, 2011 (incorporated by reference to Exhibit 3.1 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.2	First Amended and Restated Agreement of Limited Partnership of LRR Energy, L.P. dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Annual Report on Form 10-K (SEC File No. 001-35344), filed on March 27, 2012).
3.3	Certificate of Formation of LRE GP, LLC dated as of April 28, 2011 (incorporated by reference to Exhibit 3.4 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of LRE GP, LLC dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
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