UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

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 22,969,599 Common Units, 4,480,000 Subordinated Units and 22,400 General Partner Units outstanding as of July 31, 2014. The Common Units trade on the New York Stock Exchange under the ticker symbol LRE .

Table of Contents

LRR Energy, L.P.

TABLE OF CONTENTS

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements.

LRR Energy, L.P.

Consolidated Condensed Balance Sheets

(Unaudited)

(in thousands, except unit amounts)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,871	$ 4,417
Accounts receivable	9,792	9,867
Commodity derivative instruments	8,022	9,726
Due from affiliates	5,737	
Prepaid expenses	1,717	1,603
Total current assets	28,139	25,613
Property and equipment (successful efforts method)	895,352	876,674
Accumulated depletion, depreciation and impairment	(449,054)	(431,837)
Total property and equipment, net	446,298	444,837
Commodity derivative instruments	5,569	16,746
Deferred financing costs, net of accumulated amortization and other	1,039	1,154
TOTAL ASSETS	$ 481,045	$ 488,350
LIABILITIES AND UNITHOLDERS EQUITY		
Current liabilities:		
Accrued liabilities	$ 4,797	$ 2,300
Accrued capital cost	4,115	2,574
Due to affiliates		255
Commodity derivative instruments	5,783	2,217
Interest rate derivative instruments	1,304	648
Asset retirement obligations	503	488
Total current liabilities	16,502	8,482
Long-term liabilities:		
Commodity derivative instruments	3,643	174
Interest rate derivative instruments	1,915	1,554
Term loan	50,000	50,000
Revolving credit facility	195,000	200,000
Asset retirement obligations	36,933	35,838
Deferred tax liabilities	83	44
Total long-term liabilities	287,574	287,610
Total liabilities	304,076	296,092
Unitholders equity:		
General partner (22,400 units issued and outstanding as of June 30, 2014 and December 31, 2013)	277	303

Public common unitholders (18,584,790 units issued and outstanding as of June 30, 2014 and 17,710,334 units issued and outstanding as of December 31, 2013)		175,920		181,290
Affiliated common unitholders (4,089,600 units issued and outstanding as of June 30, 2014 and 1,849,600 issued and outstanding as of December 31, 2013)		216		2,093
Subordinated unitholders (4,480,000 units issued and outstanding as of June 30, 2014 and 6,720,000 units issued and outstanding as of December 31, 2013)		556		8,572
Total unitholders equity		176,969		192,258
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$	481,045	$	488,350

See accompanying notes to the unaudited consolidated condensed financial statements.

Table of Contents

LRR Energy, L.P.

Consolidated Condensed Statements of Operations

(Unaudited)

(in thousands, except per unit amounts)

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Revenues:				
Oil sales	$ 20,354	$ 19,012	$ 40,510	$ 34,475
Natural gas sales	7,565	7,720	15,664	13,800
Natural gas liquids sales	2,760	2,275	6,124	4,510
Gain (loss) on commodity derivative instruments, net	(13,328)	12,354	(18,950)	6,287
Other income	40	18	71	87
Total revenues	17,391	41,379	43,419	59,159
Operating expenses:				
Lease operating expense	6,829	5,270	12,664	12,067
Production and ad valorem taxes	2,248	2,198	4,648	4,044
Depletion and depreciation	8,680	10,129	17,145	20,239
Accretion expense	510	477	1,013	947
Loss (gain) on settlement of asset retirement obligations	21	360	61	335
General and administrative expense	2,699	2,768	5,881	6,197
Total operating expenses	20,987	21,202	41,412	43,829
Operating income (loss)	(3,596)	20,177	2,007	15,330
Other income (expense), net				
Interest expense	(2,575)	(2,249)	(5,116)	(4,514)
Gain (loss) on interest rate derivative instruments, net	(1,128)	2,657	(1,422)	2,772
Other income (expense), net	(3,703)	408	(6,538)	(1,742)
Income (loss) before taxes	(7,299)	20,585	(4,531)	13,588
Income tax expense	(38)	(62)	(112)	(67)
Net income (loss)	$ (7,337)	$ 20,523	$ (4,643)	$ 13,521
Net loss (income) attributable to common control operations				(448)
Net income (loss) available to unitholders	$ (7,337)	$ 20,523	$ (4,643)	$ 13,073
Computation of net income (loss) per limited partner unit:				
General partner s interest in net income (loss)	$ (7)	$ 21	$ (4)	$ 13
Limited partners interest in net income (loss)	$ (7,330)	$ 20,502	$ (4,639)	$ 13,060
Net income (loss) per limited partner unit (basic and diluted)	$ (0.27)	$ 0.78	$ (0.17)	$ 0.53

Weighted average number of limited partner units outstanding (basic and diluted)	26,733	26,169	26,539	24,555

See accompanying notes to the unaudited consolidated condensed financial statements.

Table of Contents

LRR Energy, L.P.

Consolidated Condensed Statement of Changes in Unitholders Equity

(Unaudited)

(in thousands)

		Limited Partners			
	General Partner	Public Common	Affiliated Common	Affiliated Subordinated	Total
Balance, December 31, 2013	$ 303	$ 181,290	$ 2,093	$ 8,572	$ 192,258
Equity offering, net of expenses		14,810			14,810
Amortization of equity awards		534			534
Conversion of subordinated units			623	(623)	
Distribution	(22)	(17,548)	(1,832)	(6,588)	(25,990)
Net income (loss)	(4)	(3,166)	(668)	(805)	(4,643)
Balance, June 30, 2014	$ 277	$ 175,920	$ 216	$ 556	$ 176,969

See accompanying notes to the unaudited consolidated condensed financial statements.

Table of Contents

LRR Energy, L.P.

Consolidated Condensed Statements of Cash Flows

(Unaudited)

(in thousands)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ (4,643)	$ 13,521
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depletion and depreciation	17,145	20,239
Accretion expense	1,013	947
Amortization of equity awards	534	253
Amortization of derivative contracts	330	508
Amortization of deferred financing costs and other	208	187
Loss (gain) on settlement of asset retirement obligations	61	335
Changes in operating assets and liabilities:		
Change in receivables	75	(2,568)
Change in prepaid expenses	(209)	(279)
Change in derivative assets and liabilities	20,605	(3,163)
Change in amounts due to/from affiliates	(5,992)	(5,446)
Change in accrued liabilities and deferred tax liabilities	2,536	2,581
Net cash provided by (used in) operating activities	31,663	27,115
CASH FLOWS FROM INVESTING ACTIVITIES		
Development of oil and natural gas properties	(17,094)	(14,375)
Disposition of oil and natural gas properties	65	
Net cash provided by (used in) investing activities	(17,029)	(14,375)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings under revolving credit facility	20,000	38,000
Principal payments on revolving credit facility	(25,000)	(24,000)
Equity offering, net of expenses	14,810	59,513
Distributions	(25,990)	(23,422)
Distribution to Lime Rock Resources		(60,672)
Contribution to Lime Rock Resources		(734)
Net cash provided by (used in) financing activities	(16,180)	(11,315)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,546)	1,425
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	4,417	3,467
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 2,871	$ 4,892
Supplemental disclosure of non-cash items to reconcile investing and financing activities		
Property and equipment:		
Accrued capital costs	$ 1,735	$ 4,662
Asset retirement obligations	(181)	(313)

See accompanying notes to the unaudited consolidated condensed financial statements.

Table of Contents

LRR Energy, L.P.

Notes to Consolidated Condensed Financial Statements

(unaudited)

1. Organization and 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 will be limited to co-issuing our debt securities and engaging in activities related thereto.

2. Summary of Significant Accounting Policies

Our accounting policies are set forth in the audited consolidated/combined financial statements in our Annual Report on Form 10-K for the year ended December 31, 2013 (2013 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 2013 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 2013 Annual Report. While the year-end condensed 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 2014 presentation. The effects of the reclassification were not material to our unaudited interim consolidated condensed financial statements.

Recent accounting pronouncements

On May 28, 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers. ASU No. 2014-09 outlined a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. The core principle of the revenue model is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity

Table of Contents

expects to be entitled in exchange for those goods or services. ASU No. 2014-09 is effective for annual reporting periods beginning after December 15, 2016 and early adoption is not permitted. We are still evaluating the impact of our adoption of ASU No. 2014-09.

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 (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, 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.

4. Fair Value Measurements

Our financial instruments, including cash and cash equivalents and accounts receivable, 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

Table of Contents

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 as of June 30, 2014 and December 31, 2013 (in thousands).

	Level 1	Level 2	Level 3	Total
June 30, 2014				
Assets:				
Commodity derivative instruments	$	$ 13,591	$	$ 13,591
Liabilities:				
Commodity derivative instruments		9,426		9,426
Interest rate derivative instruments		3,219		3,219
December 31, 2013				
Assets:				
Commodity derivative instruments	$	$ 26,472	$	$ 26,472
Liabilities:				
Commodity derivative instruments		2,391		2,391
Interest rate derivative instruments		2,202		2,202

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

Table of Contents

5. Property and Equipment

Property and equipment is stated at cost less accumulated depletion, depreciation and impairment and consisted of the following (in thousands):

	June 30, 2014	December 31, 2013
Oil and natural gas properties (successful efforts method)	$ 893,825	$ 875,126
Unproved properties	1,238	1,258
Other property and equipment	289	290
	895,352	876,674
Accumulated depletion, depreciation and impairment	(449,054)	(431,837)
Total property and equipment, net	$ 446,298	$ 444,837

We recorded $8.7 million and $10.1 million of depletion and depreciation expense for the three months ended June 30, 2014 and 2013, respectively. We recorded $17.1 million and $20.2 million of depletion and depreciation expense for the six months ended June 30, 2014 and 2013, 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 six months ended June 30, 2014 or 2013. If future oil or natural gas prices or our reserves decline, the estimated undiscounted future cash flows for the 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 six months ended June 30, 2014 (in thousands):

Beginning of period	$ 36,326
Dispositions	(84)
Liabilities incurred	181
Accretion expense	1,013
End of period	37,436
Current portion of asset retirement obligations	(503)
Asset retirement obligations non-current	$ 36,933

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, $500.0 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 $235.0 million as of June 30, 2014. Our borrowing base, which is primarily based on the estimated value of our oil, NGL, and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders at their sole discretion. As of June 30, 2014, we were in compliance with all covenants contained in the Credit Agreement.

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 $50.0 million senior secured second lien term loan to OLLC. OLLC borrowed $50.0 million under the Term Loan Agreement and used the borrowings to repay outstanding borrowings under the Credit Agreement. As of June 30, 2014, we were in compliance with all covenants contained in the Term Loan Agreement. The Term Loan Agreement was amended in June 2014 (Note 10).

Table of Contents

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 June 30, 2014, we had $245.0 million of outstanding debt and accrued interest was approximately $0.2 million. As of December 31, 2013, we had $250.0 million of outstanding debt and accrued interest was approximately $0.2 million.

Interest expense for the three months ended June 30, 2014 and 2013 was $2.6 million and $2.2 million, respectively. Interest expense for the six months ended June 30, 2014 and 2013 was $5.1 million and $4.5 million, respectively. As of June 30, 2014 and December 31, 2013, our weighted average interest rate on our outstanding indebtedness was 4.21% and 3.88%, respectively. Please refer to Note 8 below for a discussion of our interest rate derivative contracts.

8. Derivatives

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 (NGL) 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.

Table of Contents

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. We present the fair value of derivative financial instruments on a net basis in the consolidated condensed balance sheets.

At June 30, 2014, we had the following open commodity derivative contracts:

	Index	2014	2015	2016	2017
Natural gas positions					
Price swaps (MMBTUs)	NYMEX-HH	2,961,198	5,500,236	5,433,888	5,045,760
Weighted average price		$ 5.56	$ 5.72	$ 4.29	$ 4.61
Basis swaps (MMBTUs)	(1)	2,860,739	5,326,559	2,877,047	
Weighted average price		$ (0.1530)	$ (0.1661)	$ (0.1115)	$
Oil positions					
Price swaps (BBLs)	NYMEX-WTI	378,675	683,286	397,488	198,744
Weighted average price		$ 96.18	$ 93.39	$ 86.02	$ 85.75
Basis swaps (BBLs)	Argus-	195,605			
Weighted average price	Midland-Cushing	$ (1.00)	$	$	$
NGL positions					
Price swaps (BBLs)	Mont Belvieu	137,760	236,149		
Weighted average price		$ 34.72	$ 34.46	$	$

(1) Our natural gas basis swaps are traded on the following indices: Centerpoint East, Houston Ship Channel, WAHA and TEXOK.

At December 31, 2013, we had the following open commodity derivative contracts:

	Index	2014	2015	2016	2017
Natural gas positions					
Price swaps (MMBTUs)	NYMEX-HH	6,077,016	5,500,236	5,433,888	5,045,760
Weighted average price		$ 5.53	$ 5.72	$ 4.29	$ 4.61
Basis swaps (MMBTUs)	(1)	5,876,098	5,326,559	2,877,047	
Weighted average price		$ (0.1521)	$ (0.1661)	$ (0.1115)	$
Oil positions					
Price swaps (BBLs)	NYMEX-WTI	723,634	561,833	397,488	198,744
Weighted average price		$ 95.76	$ 93.16	$ 86.02	$ 85.75
Basis swaps (BBLs)	Argus-	410,400			
Weighted average price	Midland-Cushing	$ (1.00)	$	$	$

NGL positions					
Price swaps (BBLs)	Mont Belvieu	183,857	147,823		
Weighted average price		$ 34.11	$ 34.50	$	$

(1) Our natural gas basis swaps are traded on the following indices: Centerpoint East, Houston Ship Channel, WAHA and TEXOK.

Table of Contents

At June 30, 2014 and December 31, 2013, we had the following interest rate swap derivative contracts (in thousands):

Effective	Maturity		Notional Amount	Average %	Index
February 2012	February 2015	$	150,000	0.51750%	LIBOR
February 2015	February 2017		75,000	1.72500%	LIBOR
February 2015	February 2017		75,000	1.72750%	LIBOR
June 2012	June 2015		70,000	0.52375%	LIBOR
June 2015	June 2017		70,000	1.42750%	LIBOR

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 June 30, 2014							
		Current Assets		Long-term Assets		Current Liabilities		Long-term Liabilities
Interest rate								
Swaps	$		$		$	1,304	$	1,915
Gross fair value						1,304		1,915
Netting arrangements								
Net recorded fair value	$		$		$	1,304	$	1,915
Sale of natural gas production								
Price swaps	$	7,374	$	5,563	$	240	$	3
Basis swaps		2		49		413		379
Sale of crude oil production								
Price swaps		40		458		4,621		3,629
Basis swaps		648						
Sale of NGLs								
Price swaps		65		4		616		137
Gross fair value		8,129		6,074		5,890		4,148
Netting arrangements		(107)		(505)		(107)		(505)
Net recorded fair value	$	8,022	$	5,569	$	5,783	$	3,643

	As of December 31, 2013							
		Current Assets		Long-term Assets		Current Liabilities		Long-term Liabilities
Interest rate								
Swaps	$		$	637	$	648	$	2,191
Gross fair value				637		648		2,191
Netting arrangements				(637)				(637)
Net recorded fair value	$		$		$	648	$	1,554
Sale of natural gas production								
Price swaps	$	8,250	$	11,937	$	196	$	73
Basis swaps		56		211		317		65

Sale of crude oil production				
Price swaps	1,564	5,042	1,519	331
Basis swaps	227			
Sale of NGLs				
Price swaps	106	4	662	153
Gross fair value	10,203	17,194	2,694	622
Netting arrangements	(477)	(448)	(477)	(448)
Net recorded fair value	$ 9,726	$ 16,746	$ 2,217	$ 174

Table of Contents

Effect of Derivative Instruments Statements of Operations

The net gain (loss) amounts and classification related to derivative instruments for the periods indicated are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Commodity derivatives (revenue)	$ (13,328)	$ 12,354	$ (18,950)	$ 6,287
Interest rate derivatives (other income (expense), net)	(1,128)	2,657	(1,422)	2,772

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 in Our General Partner by Lime Rock Management and its Affiliates

As of June 30, 2014, 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 18.0% of our outstanding common units and all of our subordinated units, representing an approximate 31.5% limited partner interest in us. As of June 30, 2014, 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 2013 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 converted 2,240,000 subordinated units on a one-for-one basis into common units pursuant to the terms of our partnership agreement on May 16, 2014. We do not expect the second tranche of the subordinated units to convert pursuant to the provisions of our partnership agreement following our distribution for the second quarter of 2014 that will be paid on August 14, 2014. 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

As more fully described in our 2013 Annual Report, we have entered into agreements with our general partner and its affiliates. For the three months ended June 30, 2014 and 2013, we paid Lime Rock Management approximately $0.4 million and $0.2 million either directly or indirectly related to these agreements, respectively. For the six months ended June 30, 2014 and 2013, we paid Lime Rock Management approximately $0.6 million and $0.5 million either directly or indirectly related to these agreements, respectively.

Table of Contents

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 six months ended June 30, 2014 are included below (in thousands):

	ServCo	Lime Rock Resources	Total
Balance as of December 31, 2013	$ (518)	$ 263	$ (255)
Expenditures	(51,549)		(51,549)
Cash paid for expenditures	66,718		66,718
Revenues and other	(9,175)	(2)	(9,177)
Balance as of June 30, 2014	$ 5,476	$ 261	$ 5,737

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 June 30, 2014, our general partner and its affiliates held 4,089,600 of our common units, all of our subordinated units and 22,400 general partner units. During the six months ended June 30, 2014 and 2013, we paid cash distributions of $26.0 million and $23.4 million, respectively, to all unitholders as of the respective record dates.

We announced our second quarter 2014 distribution on July 18, 2014 as discussed in Note 14.

10. Unitholders Equity

At-the-Market Offering Program

On February 4, 2014, we launched an at-the-market offering program (the ATM Program) with MLV & Co. LLC (MLV) as sales agent. We may sell from time to time through MLV our common units representing limited partner interests having an aggregate offering amount of up to $75.0 million. Any sales of common units under the ATM Program may be made by any method permitted by law deemed to be an at-the-market offering defined by Rule 415 of the Securities Act, including, without limitation, sales made directly on the New York Stock Exchange, or any other existing trading market for our common units or to or through a market maker.

Our second lien term loan requires that 50% of the net cash proceeds from any equity offering be used to repay borrowings outstanding under the term loan. On June 6, 2014, we entered into an amendment to our Term Loan to waive this requirement through September 30, 2014. During the six months ended June 30, 2014, we received net proceeds from the sale of 885,135 newly issued common units of $14.8 million, after deducting underwriting discounts and commissions and offering expenses of approximately $0.5 million, and used the proceeds for general partnership purposes. During the six months ended June 30, 2014, we paid approximately $0.3 million of aggregate compensation to MLV for sales under the ATM Program.

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 $59.5 million, after deducting underwriting discounts and commissions and offering expenses of $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.

Table of Contents

Units Outstanding

As of June 30, 2014, we had 22,674,390 common units, 4,480,000 subordinated units and 22,400 general partner units outstanding. As of June 30, 2014, Fund I owned 4,089,600 common units and all of our subordinated units, representing an approximate 31.5% 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 for the following periods (in thousands, except per unit amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$ (7,337)	$ 20,523	$ (4,643)	$ 13,521
Net income (loss) attributable to common control operations				(448)
Net income (loss) available to unitholders	(7,337)	20,523	(4,643)	13,073
Less: General partner s interest in net loss (income)	7	(21)	4	(13)
Limited partners interest in net income (loss)	$ (7,330)	$ 20,502	$ (4,639)	$ 13,060
Weighted average limited partner units outstanding:				
Common units	21,121	19,449	20,376	17,835
Subordinated units	5,612	6,720	6,163	6,720
Total	26,733	26,169	26,539	24,555
Net income (loss) per limited partner unit (basic and diluted)	$ (0.27)	$ 0.78	$ (0.17)	$ 0.53

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 June 30, 2014 and 2013. The aggregate number of common units and subordinated units outstanding was 22,674,390 and 4,480,000, respectively, as of June 30, 2014. The aggregate number of common units and subordinated units outstanding was 19,448,539 and 6,720,000, respectively, as of June 30, 2013.

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 June 30, 2014, there were 1,308,345 units available for issuance under the 2011 LTIP. The 2011 LTIP is currently administered by our General Partner s board of directors or a committee thereof.

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.

Table of Contents

A summary of the status of the non-vested restricted units as of June 30, 2014, is presented below:

	Number of Non-vested Restricted Units	Weighted Average Grant-Date Fair Value
Non-vested restricted units at December 31, 2013	165,262	$
Granted	3,012	16.60
Vested	(12,341)	17.92
Forfeited	(13,691)	16.54
Non-vested restricted units at June 30, 2014	142,242	

As of June 30, 2014, there was approximately $2.1 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 2.2 years. There were 49,410 vested restricted units as of June 30, 2014.

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, if and when issued. 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.

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 or OLLC s assets represents restricted net assets pursuant to Rule 4-08(e)(3) of Regulation S-X.

14. Subsequent Events

Unit Distribution

On July 18, 2014, we announced that the board of directors of our general partner declared a cash distribution for the second quarter of 2014 of $0.4950 per outstanding unit, or $1.98 on an annualized basis. The distribution will be paid on August 14, 2014 to all unitholders of record as of the close of business on July 31, 2014. The aggregate amount of the distribution will be $13.6 million.

Commodity Hedges

Subsequent to June 30, 2014, we acquired the following commodity hedges:

	Index		2015
Oil positions			
Basis swaps (BBLs)	Argus-		397,035
Weighted average price	Midland-Cushing	$	(3.41)

Table of Contents

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, anti 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, 2013 (2013 Annual Report) 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 quarterly distributions 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, or substantial volatility of, 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*

Table of Contents

• *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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues (in thousands):				
Oil sales	$ 20,354	$ 19,012	$ 40,510	$ 34,475
Natural gas sales	7,565	7,720	15,664	13,800
Natural gas liquids sales	2,760	2,275	6,124	4,510
Gain (loss) on commodity derivative instruments, net	(13,328)	12,354	(18,950)	6,287
Other income	40	18	71	87
Total revenues	17,391	41,379	43,419	59,159

Table of Contents

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Expenses (in thousands):				
Lease operating expense	6,829	5,270	12,664	12,067
Production and ad valorem taxes	2,248	2,198	4,648	4,044
Depletion and depreciation	8,680	10,129	17,145	20,239
General and administrative expense	2,699	2,768	5,881	6,197
Interest expense	2,575	2,249	5,116	4,514
Loss (gain) on interest rate derivative instruments, net	1,128	(2,657)	1,422	(2,772)
Production:				
Oil (MBbls)	216	210	434	398
Natural gas (MMcf)	1,666	1,843	3,288	3,651
NGLs (MBbls)	90	73	175	145
Total (MBoe)	584	590	1,157	1,152
Average net production (Boe/d)	6,418	6,484	6,392	6,365
Average sales price:				
Oil (per Bbl):				
Sales price	$ 94.23	$ 90.53	$ 93.34	$ 86.62
Effect of settled commodity derivative instruments	(3.50)	0.39	(2.14)	0.80
Realized price	$ 90.73	$ 90.92	$ 91.20	$ 87.42
Natural gas (per Mcf):				
Sales price	$ 4.54	$ 4.19	$ 4.76	$ 3.78
Effect of settled commodity derivative instruments	0.71	0.87	0.62	1.41
Realized price	$ 5.25	$ 5.06	$ 5.38	$ 5.19
NGLs (per Bbl):				
Sales price	$ 30.67	$ 31.16	$ 34.99	$ 31.10
Effect of settled commodity derivative instruments	(1.81)	6.26	(2.77)	5.49
Realized price	$ 28.86	$ 37.42	$ 32.22	$ 36.59
Average unit cost per Boe:				
Lease operating expenses	$ 11.70	$ 8.93	$ 10.95	$ 10.48
Production and ad valorem taxes	3.85	3.72	4.02	3.51
Depletion and depreciation	14.87	17.16	14.82	17.58
General and administrative expenses	4.62	4.69	5.08	5.38

Our Results for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013

We recorded a net loss of $7.3 million for the three months ended June 30, 2014 compared to net income of $20.5 million during the three months ended June 30, 2013, primarily related to losses on commodity derivative instruments, higher lease operating expenses, offset by increased revenues and lower depletion and depreciation expense. 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 three months ended June 30, 2013 and June 30, 2014 follows (in thousands):

Oil, natural gas and NGL revenues-prior period	$	29,007
Increase (decrease)		
Price realization		
Oil		777
Natural gas		645
NGLs		(36)
Sales volumes		
Oil		565
Natural gas		(800)
NGLs		521
Oil, natural gas and NGL revenues-current period	$	30,679

Table of Contents

Sales revenues increased from $29.0 million for the three months ended June 30, 2013 to $30.7 million for the three months ended June 30, 2014, primarily due to higher commodity price realizations and oil and NGL sales volumes offset by lower natural gas volumes. Sales revenues for the three months ended June 30, 2014 consisted of oil sales of $20.3 million, natural gas sales of $7.6 million and NGL sales of $2.8 million. Sales revenues for the three months ended June 30, 2013 consisted of oil sales of $19.0 million, natural gas sales of $7.7 million and NGL sales of $2.3 million.

Our production volumes for the three months ended June 30, 2014 included 306 MBbls of oil and NGLs and 1,666 MMcf of natural gas, or 3,363 Bbl/d of oil and NGLs and 18,308 Mcf/d of natural gas. On an equivalent basis, production for the period was 584 MBoe, or 6,418 Boe/d. Our average net production for the three months ended June 30, 2014 was negatively impacted by flaring at the Red Lake field of approximately 30 Boe/d due to third-party compression limits. Our production volumes for the three months ended June 30, 2013 included 283 MBbls of oil and NGLs and 1,843 MMcf of natural gas, or 3,110 Bbl/d of oil and NGLs and 20,253 Mcf/d of natural gas. On an equivalent basis, production for the period was 590 MBoe, or 6,484 Boe/d. Our average net production for the three months ended June 30, 2013 was negatively impacted by flaring at the Red Lake field of approximately 90 Boe/d due to third-party compression limits.

Our average sales price per Bbl for oil and NGLs for the three months ended June 30, 2014, excluding the effect of commodity derivative contracts, was $94.23 and $30.67, respectively. Our average sales price per Mcf of natural gas for the three months ended June 30, 2014, excluding the effect of commodity derivative contracts, was $4.54. Our average sales price per Bbl for oil and NGLs for the three months ended June 30, 2013, excluding the effect of commodity derivative contracts, was $90.53 and $31.16, respectively. Our average sales price per Mcf of natural gas for the three months ended June 30, 2013, excluding the effect of commodity derivative contracts, was $4.19.

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 June 30, 2014 of $13.3 million, which was comprised of positive net cash settlements and amortization of purchases of approximately $0.3 million and declines in the fair value of derivatives of approximately $13.6 million. For the three months ended June 30, 2013, we recorded a net gain from our commodity hedging program of $12.3 million, which was comprised of positive net cash settlements and amortization of approximately $2.1 million and positive fluctuations in fair value of derivatives of approximately $10.2 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 $6.8 million, or $11.70 per Boe, for the three months ended June 30, 2014 compared to $5.3 million, or $8.93 per Boe, for the three months ended June 30, 2013. The primary driver of the increased lease operating expenses was higher costs at our Red Lake field associated with the increased development activity and production offset by lower workover expenses.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were $2.2 million, or $3.85 per Boe, for the three months ended June 30, 2014 compared to $2.2 million, or $3.72 per Boe, for the three months ended June 30, 2013. Production taxes accounted for approximately $2.1 million and ad valorem taxes for approximately $0.1 million of the total taxes recorded during the three months ended June 30, 2014. Production taxes accounted for approximately $2.0 million and ad valorem taxes for approximately $0.2 million of the total taxes recorded during the three months ended June 30, 2013.

Depletion and Depreciation. Our depletion and depreciation expense was $8.7 million, or $14.87 per Boe, for the three months ended June 30, 2014 compared to $10.1 million, or $17.16 per Boe, for the three months ended June 30, 2013. The decrease in depletion and depreciation expense and per Boe amounts was primarily related lower property and equipment balances as of June 30, 2014.

Impairment of Oil and Natural Gas Properties. We did not record an impairment charge in the three months ended June 30, 2014 and 2013. If future oil or natural gas prices or reserves decline, the estimated undiscounted future cash flows for our 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 July 31, 2014, the NYMEX-WTI oil spot price was $98.17 per Bbl and the NYMEX-Henry Hub natural gas spot price was $3.74 per MMBtu.

Table of Contents

General and Administrative Expenses. Our general and administrative expenses were $2.7 million, or $4.62 per Boe, for the three months ended June 30, 2014 compared to $2.8 million, or $4.69 per Boe, for the three months ended June 30, 2013.

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 $2.6 million and $2.2 million for the three months ended June 30, 2014 and 2013, respectively.

Effects of Interest Rate Derivatives. Loss on interest rate derivative contracts, net, was $1.1 million for the three months ended June 30, 2014, including $0.2 million in negative cash settlements and $0.9 million in declines in fair value of the derivatives. Gain on interest rate derivative contracts, net, was $2.7 million for the three months ended June 30, 2013, including $0.2 million in negative cash settlements and $2.9 million in positive fluctuations in fair value of the derivatives.

Our Results for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013

We recorded a net loss of $4.6 million for the six months ended June 30, 2014 compared to net income of $13.5 million during the six months ended June 30, 2013, primarily related to losses on commodity derivative instruments, net and higher operating expenses, offset by increased revenues and lower depletion and depreciation expense. 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 six months ended June 30, 2013 and June 30, 2014 follows (in thousands):

Oil, natural gas and NGL revenues-prior period	$	52,785
Increase (decrease)		
Price realization		
Oil		2,675
Natural gas		3,592
NGLs		564
Sales volumes		
Oil		3,360
Natural gas		(1,728)
NGLs		1,050
Oil, natural gas and NGL revenues-current period	$	62,298

Sales revenues increased from $52.8 million for the six months ended June 30, 2013 to $62.3 million for the six months ended June 30, 2014, primarily due to higher commodity price realizations and oil and NGL sales volumes offset by lower natural gas volumes. Sales revenues for the six months ended June 30, 2014 consisted of oil sales of $40.5 million, natural gas sales of $15.7 million and NGL sales of $6.1 million. Sales revenues for the six months ended June 30, 2013 consisted of oil sales of $34.5 million, natural gas sales of $13.8 million and NGL sales of $4.5 million.

Our production volumes for the six months ended June 30, 2014 included 609 MBbls of oil and NGLs and 3,288 MMcf of natural gas, or 3,365 Bbl/d of oil and NGLs and 18,166 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,157 MBoe, or 6,392 Boe/d. Our average net production for the six months ended June 30, 2014 was negatively impacted by flaring at the Red Lake field of approximately 50 Boe/d due to third-party compression limits. Our production volumes for the six months ended June 30, 2013 included 543 MBbls of oil and NGLs and 3,651 MMcf of natural gas, or 3,000 Bbl/d of oil and NGLs and 20,171 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,152 MBoe, or 6,365 Boe/d. Our average net production for the six months ended June 30, 2013 was negatively impacted by flaring at the Red Lake field of approximately 80 Boe/d due to third-party compression limits.

Table of Contents

Our average sales price per Bbl for oil and NGLs for the six months ended June 30, 2014, excluding the effect of commodity derivative contracts, was $93.34 and $34.99, respectively. Our average sales price per Mcf of natural gas for the six months ended June 30, 2014, excluding the effect of commodity derivative contracts, was $4.76. Our average sales price per Bbl for oil and NGLs for the six months ended June 30, 2013, excluding the effect of commodity derivative contracts, was $86.62 and $31.10, respectively. Our average sales price per Mcf of natural gas for the six months ended June 30, 2013, excluding the effect of commodity derivative contracts, was $3.78.

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 six months ended June 30, 2014 of $18.9 million, which was comprised of positive net cash settlements and amortization of purchases of approximately $0.6 million and declines in the fair value of derivatives of approximately $19.5 million. For the six months ended June 30, 2013, we recorded a net gain from our commodity hedging program of $6.3 million, which was comprised of positive net cash settlements and amortization of approximately $6.3 million and positive fluctuations in fair value of derivatives of less than $0.1 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 $12.7 million, or $10.95 per Boe, for the six months ended June 30, 2014 compared to $12.1 million, or $10.48 per Boe, for the six months ended June 30, 2013. Lease operating expenses increased by approximately $1.5 million primarily due to increased development activity and production at the Red Lake field offset by lower workover expenses of approximately $0.9 million.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were $4.6 million, or $4.02 per Boe, for the six months ended June 30, 2014 compared to $4.0 million, or $3.51 per Boe, for the six months ended June 30, 2013. The increase in production and ad valorem taxes was primarily due to increased severance taxes at the Red Lake field. Production taxes accounted for approximately $4.3 million and ad valorem taxes for $0.3 million of the total taxes recorded during the six months ended June 30, 2014. Production taxes accounted for approximately $3.6 million and ad valorem taxes for $0.4 million of the total taxes recorded during the six months ended June 30, 2013.

Depletion and Depreciation. Our depletion and depreciation expense was $17.1 million, or $14.82 per Boe, for the six months ended June 30, 2014 compared to $20.2 million, or $17.58 per Boe, for the six months ended June 30, 2013. The decrease in depletion and depreciation expense and per Boe amounts was primarily related lower property and equipment balances as of June 30, 2014.

Impairment of Oil and Natural Gas Properties. We did not record an impairment charge in the six months ended June 30, 2014 and 2013. If future oil or natural gas prices or reserves decline, the estimated undiscounted future cash flows for our 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 July 31, 2014, the NYMEX-WTI oil spot price was $98.17 per Bbl and the NYMEX-Henry Hub natural gas spot price was $3.74 per MMBtu.

General and Administrative Expenses. Our general and administrative expenses were $5.9 million, or $5.08 per Boe, for the six months ended June 30, 2014 compared to $6.2 million, or $5.38 per Boe, for the six months ended June 30, 2013.

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 $5.1 million and $4.5 million for the six months ended June 30, 2014 and 2013, respectively.

Effects of Interest Rate Derivatives. Loss on interest rate derivative contracts, net, was $1.4 million for the six months ended June 30, 2014, including $0.4 million in negative cash settlements and $1.0 million in declines in fair value of the derivatives. Gain on interest rate derivative contracts, net, was $2.8 million for the six months ended June 30, 2013, including $0.3 million in negative cash settlements and $3.1 million in positive fluctuations in fair value of the derivatives.

Table of Contents

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 (loss), our most directly comparable financial performance measure calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income (loss) plus or minus:

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

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our financial performance as compared to that of other companies and partnerships in our industry, without regard to financing methods, capital structure or historical cost basis.

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

Distributable Cash Flow is a supplemental financial measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us (prior to the establishment of any retained cash reserve by our general partner) to the cash distributions we expect to pay our unitholders. Distributable Cash Flow is also an important financial measure for our unitholders as it serves as an indicator of our success in providing a cash return on investment. Specifically, distributable cash flow indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable Cash Flow is a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the yield is based on the amount of cash distributions the entity pays to a unitholder compared to the unit price.

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 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 (loss), operating income (loss), 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 June 30, 2014 and 2013 was $19.6 million and $21.3 million, respectively. The decrease was primarily driven by higher lease operating expenses. Our Adjusted EBITDA for the six months ended June 30, 2014 and 2013 was $40.7 million and $37.6 million, respectively. The increase was primarily driven by higher revenues.

Our Distributable Cash Flow for the three months ended June 30, 2014 and 2013 was $11.8 million and $13.9 million, respectively. The decrease in Distributable Cash Flow was driven by the decreased Adjusted EBITDA as discussed above and increased cash interest expense. Our Distributable Cash Flow for the six months ended June 30, 2014 and 2013 was $25.2 million and $22.7 million, respectively. The increase in Distributable Cash Flow was driven by the increased Adjusted EBITDA as discussed above offset by increased cash interest expense.

Table of Contents

Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Income (Loss)

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

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
(in thousands)				
Net income (loss)	$ (7,337)	$ 20,523	$ (4,643)	$ 13,521
Income tax expense	38	62	112	67
Interest expense-net, including loss (gain) on interest rate derivative instruments, net	3,703	(408)	6,538	1,742
Depletion and depreciation	8,680	10,129	17,145	20,239
Accretion of asset retirement obligations	510	477	1,013	947
Amortization of equity awards	249	138	534	253
Loss (gain) on settlement of asset retirement obligations	21	360	61	335
Loss (gain) on commodity derivative instruments, net	13,328	(12,354)	18,950	(6,287)
Commodity derivative instrument net cash settlements	444	2,404	967	6,756
Impairment of oil and natural gas properties				
Adjusted EBITDA	$ 19,636	$ 21,331	$ 40,677	$ 37,573
Adjusted EBITDA	19,636	21,331	40,677	37,573
Income tax expense	(44)	(47)	(88)	(73)
Cash interest expense	(2,757)	(2,314)	(5,401)	(4,616)
Estimated maintenance capital (1)	(5,000)	(5,075)	(10,000)	(10,150)
Distributable cash flow	$ 11,835	$ 13,895	$ 25,188	$ 22,734

(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 and borrowings under our credit facility and term loan and equity offerings under our recently established at-the-market offering program (the ATM Program), described below. We may issue additional equity and debt as needed.

On February 4, 2014, we launched the ATM Program with MLV & Co. LLC (MLV) as sales agent. We may sell from time to time through MLV our common units representing limited partner interests having an aggregate offering amount of up to $75.0 million. Any sales of common units under the ATM Program may be made by any method permitted by law deemed to be an at-the-market offering defined by Rule 415 of the Securities Act, including, without limitation, sales made directly on the New York Stock Exchange, on any other existing trading market for our common units or to or through a market maker. During the six months ended June 30, 2014, we received net proceeds from the sale of 885,135 newly issued common units of $14.8 million, after deducting underwriting discounts and commissions and offering expenses of $0.5 million, and used the proceeds for general partnership purposes. During the six months ended June 30, 2014, we paid approximately $0.3 million of aggregate compensation to MLV for sales under the ATM Program.

Table of Contents

Our second lien term loan requires that 50% of the net cash proceeds from any equity offering be used to repay borrowings outstanding under the term loan. On June 6, 2014, we entered into an amendment to our term loan to waive this requirement through September 30, 2014.

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.

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 July 31, 2014, quarterly distributions to all of our unitholders at our current quarterly distribution rate would total $13.6 million.

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 intend to use primarily external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, 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 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 June 30, 2014, we had borrowing capacity of $40.0 million under our $500.0 million revolving credit facility ($235.0 million borrowing base less $195.0 million of outstanding borrowings) and $2.9 million of cash on hand. As of June 30, 2014, we had no available borrowing capacity under our $50.0 million term loan.

Table of Contents

Based upon current oil and natural gas price expectations and our commodity derivatives positions at June 30, 2014, which cover 86% of our estimated production from total proved developed producing reserves, we anticipate that our cash on hand, cash flow from operations, proceeds from our ATM Program and available borrowing capacity under our revolving credit facility will provide us sufficient working capital to fund our total planned 2014 capital expenditures and annualized cash distributions as described above.

We expect to spend $37.5 million in total capital expenditures in 2014, of which $20.0 million represents maintenance capital expenditures on the development of our existing oil and natural gas properties.

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 2014 through external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities, including through our ATM Program.

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, $500.0 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 $235.0 million as of June 30, 2014. 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.

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 Agreement. Additionally, we will not be able to pay 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 Agreement after giving effect to such distribution.

If we fail to perform our obligations under the covenants described in our 2013 Annual Report, the revolving credit commitments could be terminated and any outstanding indebtedness under the Credit Agreement, together with accrued interest, could be declared immediately due and payable. As of June 30, 2014, we were in compliance with our covenants contained in the Credit Agreement.

At June 30, 2014, we had $195.0 million of outstanding borrowings under our Credit Agreement and available borrowing capacity of $40.0 million. As of July 31, 2014, we had approximately $190.0 million of outstanding borrowings under our Credit Agreement and available borrowing capacity of approximately $45.0 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 $50.0 million senior secured second lien term loan to OLLC. OLLC borrowed $50.0 million under the Term Loan Agreement and used the borrowings to repay outstanding borrowings under the Credit Agreement.

The Term Loan Agreement contains various covenants and restrictive provisions as described in our 2013 Annual Report. As of June 30, 2014, we were in compliance with all covenants contained in the Term Loan Agreement.

Table of Contents

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 June 30, 2014. 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**
2014	$ 96.18	2,058	$ 34.72	749	$ 5.56	16,093
2015	$ 93.39	1,872	$ 34.46	647	$ 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 June 30, 2014. 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**
2014	$ (0.2131)	6,268	$ (0.0839)	3,317	$ (0.1291)	5,070	$ (0.1229)	892
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

The following table summarizes, for the periods presented, our oil basis swaps in place as of June 30, 2014. 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.

	Argus Midland-Cushing	
Term	**$/Bbl**	**Bbl/d**
2014	$ (1.00)	1,063

Cash Flows

Cash flows provided by (used in) operating, investing and financing activities were as follows for the periods indicated (in thousands):

	Six Months Ended June 30, 2014	2013
Net cash provided by (used in):		
Operating activities	$ 31,663	$ 27,115
Investing activities	(17,029)	(14,375)
Financing activities	(16,180)	(11,315)

Table of Contents

Operating Activities.

Net cash provided by operating activities was $31.7 million and $27.1 million for the six months ended June 30, 2014 and 2013, 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 $11.6 million and $17.1 million at June 30, 2014 and December 31, 2013, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $2.9 million and $4.4 million at June 30, 2014 and December 31, 2013, respectively.

Investing Activities.

Net cash used in investing activities was $17.0 million and $14.4 million for the six months ended June 30, 2014 and 2013, respectively, which primarily represented additions to our property and equipment balances during the periods.

Financing Activities.

Cash flows used in financing activities was $16.2 million for the six months ended June 30, 2014, and consisted of net proceeds received from an equity offering of $14.8 million offset by distributions to unitholders of $26.0 million and net repayments on the Credit Agreement of $5.0 million.

Cash flows used in financing activities was approximately $11.3 million for the six months ended June 30, 2013, which consisted of net proceeds from the March 2013 equity offering of $59.5 million and net borrowings of $14.0 million offset by distributions paid to our unitholders of $23.4 million and contributions and distributions to Lime Rock Resources of $61.4 million.

Off-Balance Sheet Arrangements

As of June 30, 2014, 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 2013 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 2013 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 June 30, 2014.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 2013 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).

Table of Contents

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).
10.1	Third Amendment dated as of June 6, 2014 to Second Lien Credit Agreement dated as of June 28, 2012, among LRE Operating, LLC, as Borrower, LRR Energy, L.P., as Parent Guarantor, the lenders from time to time party thereto and Wells Fargo Energy Capital, Inc., as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on June 11, 2014).
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.
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

Table of Contents

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: August 6, 2014	By:	/s/ Eric Mullins Eric Mullins Co-Chief Executive Officer
Date: August 6, 2014	By:	/s/ Jaime R. Casas Jaime R. Casas Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)

Table of Contents

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).
10.1	Third Amendment dated as of June 6, 2014 to Second Lien Credit Agreement dated as of June 28, 2012, among LRE Operating, LLC, as Borrower, LRR Energy, L.P., as Parent Guarantor, the lenders from time to time party thereto and Wells Fargo Energy Capital, Inc., as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on June 11, 2014).
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.
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