LRR Energy, L.P.
Form 10-Q
August 04, 2015
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2015

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

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

There were 28,074,433 Common Units and 22,400 General Partner Units outstanding as of July 31, 2015. 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

	Caption	Page
	PART I FINANCIAL INFORMATION	
Item 1.	Financial Statements.	
	Unaudited Consolidated Condensed Balance Sheets as of June 30, 2015 and December 31, 2014	1
	Unaudited Consolidated Condensed Statements of Operations for the Three and Six Months Ended June 30, 2015 and 2014	2
	Unaudited Consolidated Condensed Statement of Changes in Unitholders Equity as of June 30, 2015	3
	Unaudited Consolidated Condensed Statements of Cash Flows for the Six Months Ended June 30, 2015 and 2014	4
	Notes to Unaudited Consolidated Condensed Financial Statements	5
Item 2.	Management s Discussion and Analysis of Financial Condition and Results of Operations .	20
Item 3.	Quantitative and Qualitative Disclosures About Market Risk.	31
Item 4.	Controls and Procedures.	31
	PART II OTHER INFORMATION	
Item 1.	Legal Proceedings.	31
Item 1A.	Risk Factors.	32
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds.	32
Item 3.	Defaults Upon Senior Securities.	32
Item 4.	Mine Safety Disclosures.	32
Item 5.	Other Information.	32
Item 6.	Exhibits.	32
	Signatures.	35

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, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,681	$ 3,576
Accounts receivable	8,659	11,124
Commodity derivative instruments	32,087	45,924
Due from affiliates	1,456	5,697
Prepaid expenses	1,240	1,840
Total current assets	51,123	68,161
Property and equipment (successful efforts method)	972,398	956,326
Accumulated depletion, depreciation and impairment	(559,893)	(506,368)
Total property and equipment, net	412,505	449,958
Commodity derivative instruments	37,159	38,540
Deferred financing costs, net of accumulated amortization and other assets	2,076	2,295
TOTAL ASSETS	$ 502,863	$ 558,954
LIABILITIES AND UNITHOLDERS EQUITY		
Current liabilities:		
Accrued liabilities	$ 9,910	$ 5,506
Accrued capital cost	7,642	9,176
Commodity derivative instruments	783	556
Interest rate derivative instruments	2,781	2,327
Asset retirement obligations	2,153	1,065
Total current liabilities	23,269	18,630
Long-term liabilities:		
Commodity derivative instruments	94	232
Interest rate derivative instruments	960	817
Term loan	50,000	50,000
Revolving credit facility	235,000	230,000
Asset retirement obligations	40,558	40,539
Deferred tax liabilities		99
Total long-term liabilities	326,612	321,687
Total liabilities	349,881	340,317
Unitholders equity:		
General partner (22,400 units issued and outstanding as of June 30, 2015 and December 31, 2014)	(9,139)	310
	162,121	208,273

Public common unitholders (19,504,833 units issued and outstanding as of June 30, 2015 and 19,492,291 units issued and outstanding as of December 31, 2014)				
Affiliated common unitholders (8,569,600 units issued and outstanding as of June 30, 2015 and 4,089,600 units issued and outstanding as of December 31, 2014)				4,643
Subordinated unitholders (4,480,000 units issued and outstanding as of December 31, 2014)				5,411
Total unitholders equity		152,982		218,637
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$	502,863	$	558,954

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,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues:				
Oil sales	$ 14,227	$ 20,354	$ 26,291	$ 40,510
Natural gas sales	3,720	7,565	7,986	15,664
Natural gas liquids sales	1,661	2,760	2,832	6,124
Gain (loss) on commodity derivative instruments, net	(8,927)	(13,328)	9,755	(18,950)
Other income	26	40	55	71
Total revenues	10,707	17,391	46,919	43,419
Operating expenses:				
Lease operating expense	6,008	6,829	12,780	12,664
Production and ad valorem taxes	1,482	2,248	2,748	4,648
Depletion and depreciation	8,694	8,680	17,574	17,145
Impairment of oil and natural gas properties	256		35,962	
Accretion expense	518	510	1,029	1,013
Loss (gain) on settlement of asset retirement obligations	4	21	68	61
General and administrative expense	12,673	2,699	16,464	5,881
Total operating expenses	29,635	20,987	86,625	41,412
Operating income (loss)	(18,928)	(3,596)	(39,706)	2,007
Other income (expense), net				
Interest expense	(3,120)	(2,575)	(5,889)	(5,116)
Gain (loss) on interest rate derivative instruments, net	(322)	(1,128)	(1,673)	(1,422)
Other income (expense), net	(3,442)	(3,703)	(7,562)	(6,538)
Income (loss) before taxes	(22,370)	(7,299)	(47,268)	(4,531)
Income tax (expense) benefit	56	(38)	18	(112)
Net income (loss) available to unitholders	$ (22,314)	$ (7,337)	$ (47,250)	$ (4,643)
Computation of net income (loss) per limited partner unit:				
General partner s interest in net income (loss)	$ (7,595)	$ (7)	$ (9,434)	$ (4)
Limited partners interest in net income (loss)	$ (14,719)	$ (7,330)	$ (37,816)	$ (4,639)
Net income (loss) per limited partner unit (basic and diluted)	$ (0.52)	$ (0.27)	$ (1.35)	$ (0.17)
	28,074	26,733	28,073	26,539

Weighted average number of limited partner units outstanding (basic and diluted)

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	Subordinated	Total
Balance, December 31, 2014	$ 310	$ 208,273	$ 4,643	$ 5,411	$ 218,637
Equity offering, net of expenses		3			3
Amortization of equity awards		838			838
Conversion of subordinated units			3,182	(3,182)	
Distribution	(15)	(14,201)	(2,801)	(2,229)	(19,246)
Net income (loss)	(9,434)	(32,792)	(5,024)		(47,250)
Balance, June 30, 2015	$ (9,139)	$ 162,121	$	$	$ 152,982

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, 2015	Six Months Ended June 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ (47,250)	$ (4,643)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depletion and depreciation	17,574	17,145
Impairment of oil and natural gas properties	35,962	
Accretion expense	1,029	1,013
Amortization of equity awards	838	534
Amortization of derivative contracts	243	330
Amortization of deferred financing costs and other	341	208
Loss (gain) on settlement of asset retirement obligations	68	61
Changes in operating assets and liabilities:		
Change in receivables	2,465	75
Change in prepaid expenses	483	(209)
Change in derivative assets and liabilities	15,659	20,605
Change in amounts due to/from affiliates	4,241	(5,992)
Change in accrued liabilities and deferred tax liabilities	4,301	2,536
Net cash provided by (used in) operating activities	35,954	31,663
CASH FLOWS FROM INVESTING ACTIVITIES		
Development of oil and natural gas properties	(17,376)	(17,094)
Acquisition of oil and natural gas properties	(230)	
Disposition of oil and natural gas properties		65
Net cash provided by (used in) investing activities	(17,606)	(17,029)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings under revolving credit facility	10,000	20,000
Principal payments on revolving credit facility	(5,000)	(25,000)
Equity offering, net of expenses	3	14,810
Distributions	(19,246)	(25,990)
Net cash provided by (used in) financing activities	(14,243)	(16,180)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	4,105	(1,546)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	3,576	4,417
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 7,681	$ 2,871

See accompanying notes to the unaudited consolidated condensed financial statements.

4

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 are limited to co-issuing our debt securities and engaging in activities related thereto.

Merger with Vanguard Natural Resources, LLC

On April 20, 2015, we entered into a Purchase Agreement and Plan of Merger (the Merger Agreement) with Vanguard Natural Resources, LLC (Vanguard), Lighthouse Merger Sub, LLC, a wholly owned indirect subsidiary of Vanguard (Merger Sub and together with Vanguard, the Vanguard Entities), Lime Rock Management, Fund I, Fund II (together with the Fund I and Lime Rock Management, the GP Sellers) and LRE GP, LLC (our General Partner and together with the GP Sellers and the Partnership, the Partnership Entities). Upon the terms and conditions set forth in the Merger Agreement, Merger Sub will be merged with and into the Partnership, with the Partnership continuing as the surviving entity and as a wholly owned subsidiary of Vanguard (the Merger) and, at the same time, all of the limited liability company interests in our General Partner will be acquired by Vanguard. Based upon the recommendation of the conflicts committee of the board of directors of our General Partner (the Board), the Board approved the Merger Agreement on April 20, 2015.

At the effective time of the Merger (the Effective Time), each of our common units issued and outstanding immediately prior to the Effective Time will be converted into the right to receive 0.550 common units representing limited liability company interests in Vanguard (Vanguard Units) or, in the case of fractional Vanguard Units, cash (without interest and rounded up to the nearest whole cent) in an amount equal to the product of (i) such fractional part of a Vanguard Unit multiplied by (ii) the average closing price for a Vanguard Unit as reported on the NASDAQ Global Select Market (the NASDAQ) for the ten consecutive full trading days ending at the close of trading on the full trading day immediately preceding the closing date of the transactions contemplated by the Merger Agreement (the Closing Date). Each of our restricted

common units that is outstanding pursuant to the 2011 LTIP will vest immediately prior to the Effective Time and be converted into the right to receive Vanguard Units. In addition, on the Closing Date, Vanguard will issue and deliver to the GP Sellers 12,320 Vanguard Units in exchange for all of the limited liability interests in our General Partner (the GP Equity Consideration).

As a condition to closing of transactions contemplated under the Merger Agreement, the parties have agreed to execute and deliver a Termination and Continuing Obligations Agreement (the Termination Agreement) substantially in the form attached as an exhibit to the Merger Agreement. Pursuant to the Termination Agreement, (i) that certain Omnibus Agreement, entered into, and effective as of, November 16, 2011 (the Omnibus Agreement), by and among us, our General Partner, OLLC, Fund I, LRR GP, LLC, the ultimate general partner of each of the Fund I entities, and Lime Rock Management, will be terminated and (ii) the Fund I entities, severally and in proportion to each entity s Property Contributor Percentage (as defined in the Omnibus Agreement), will agree to

Table of Contents

indemnify the Partnership, our General Partner, OLLC and all of our and their respective subsidiaries from and against any losses arising out of any federal, state or local income tax liabilities attributable to the ownership or operation of the oil and natural gas properties owned or leased by any of the Partnership, our General Partner, OLLC or our or their respective subsidiaries prior to the closing of our initial public offering. The indemnification obligations of Fund I under the Termination Agreement will survive until the first anniversary of the Closing Date.

The Partnership Entities and the Vanguard Entities have each made certain representations and warranties and agreed to certain covenants in the Merger Agreement. Each of the Partnership, our General Partner and Vanguard has agreed, among other things, subject to certain exceptions, to conduct its respective business in the ordinary course during the period between the execution of the Merger Agreement and the Effective Time (unless the Merger Agreement is earlier terminated in accordance with its terms). In addition, we have agreed not to solicit alternative business combination transactions during such period, and, subject to certain exceptions, not to engage in discussions or negotiations regarding any alternative business combination transactions during such period.

The closing of the Merger is subject to the satisfaction or waiver of certain customary conditions, including, among others, (i) the approval of the Merger Agreement by our unitholders; (ii) the registration statement on Form S-4 used to register the Vanguard Units to be issued in the Merger being declared effective by the Securities and Exchange Commission (the SEC); (iii) the approval for listing on the NASDAQ of the Vanguard Units to be issued in the Merger; (iv) subject to specified materiality standards, the accuracy of the representations and warranties of, and the performance of all covenants by, the parties; (v) the delivery of certain tax opinions; and (vi) entry into the Termination Agreement by the parties thereto.

The Merger Agreement contains certain termination rights for each of the Partnership and Vanguard, including, among others, if (i) the Merger is not consummated on or before December 31, 2015; (ii) the requisite approval of the Merger Agreement by our unitholders is not obtained; and (iii) the other party breaches a representation, warranty or covenant, and such breach results in the failure of certain closing conditions to be satisfied (a terminable breach). The Merger Agreement also provides that (a) we may terminate the Merger Agreement to enter into a third party s superior proposal and (b) Vanguard may terminate the Merger Agreement if the Board changes its recommendation to our unitholders to approve the Merger Agreement (a Partnership Change in Recommendation); provided, in each case, that we pay Vanguard the Termination Fee (as described below).

The Merger Agreement provides for the payment of a termination fee of approximately $7.3 million (the Termination Fee) by the Partnership to Vanguard upon the termination of the Merger Agreement under specified circumstances, including if: (i) (a) prior to our unitholder meeting, a third party proposal has been publicly submitted, publicly proposed or publicly disclosed and has not been withdrawn at the time of such meeting, (b) thereafter, the Merger Agreement is terminated in accordance with its terms under specified circumstances, and (c) prior to the date that is 12 months after the date of the Merger Agreement is terminated, we enter into or consummate any definitive agreement related to a third party proposal; (ii) Vanguard terminates the Merger Agreement due to a Partnership Change in Recommendation; or (iii) we terminate the Merger Agreement to enter into a third party s superior proposal. The Merger Agreement also provides that the non-terminating party may be required to pay the other party s expenses (up to a maximum of approximately $1.2 million (the Expenses)) if either party terminates the Merger Agreement due to a terminable breach by the other party. If the Termination Fee is payable at a time when Vanguard has received or concurrently receives payment from us in respect of Expenses, the Termination Fee will be reduced by the amount of such Expenses received by Vanguard.

The special meeting of unitholders to approve the Merger Agreement is scheduled to occur on September 10, 2015. Our unitholders of record at the close of business on July 24, 2015 will be entitled to receive notice of the special meeting and vote at the special meeting.

2. Summary of Significant Accounting Policies

Our accounting policies are set forth in the audited consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2014 (2014 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 financial statements and notes in our 2014 Annual Report.

Table of Contents

Basis of presentation

These interim financial statements are unaudited and have been prepared pursuant to the rules and regulations of the 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 financial statements in our 2014 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.

Recent accounting pronouncements

On April 10, 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. ASU No. 2014-08 amends the definition of a discontinued operation and requires entities to provide additional disclosures about discontinued operations as well as disposal transactions that do not meet the discontinued-operations criteria. We adopted ASU No. 2014-08 on January 1, 2015. The adoption of ASU No. 2014-08 did not have a material impact on our consolidated condensed financial position, results of operations or cash flows.

On May 28, 2014, the FASB issued ASU No. 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 expects to be entitled in exchange for those goods or services. In July 2015, the FASB approved a delay in adoption for public entities and ASU No. 2014-09 is effective for annual periods beginning after December 15, 2017.We are still evaluating the impact of our adoption of ASU No. 2014-09.

On August 27, 2014, the FASB issued ASU No. 2014-15, Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern. ASU No. 2014-15 provides guidance on determining when and how reporting entities must disclose going concern uncertainties in their financial statements. The new standard requires management to perform interim and annual assessments of an entity s financial statements (or within one year after the date on which the financial statements are available to be issued, when applicable). Further, an entity must provide certain disclosures if there is substantial doubt about the entity s ability to continue as a going concern. ASU No. 2014-15 is effective for annual periods ending after December 15, 2016, and interim periods thereafter; early adoption is permitted. We do not expect the adoption of ASU No. 2014-15 to have a material impact on our financial statement disclosures.

On February 18, 2015, the FASB issued No. ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. ASU No. 2015-02 applies to entities in all industries and provides a new scope exception to registered money market funds and similar unregistered money market funds. The standard makes targeted amendments to the current consolidation guidance and ends the deferral granted to investment companies from applying the variable interest entities guidance. ASU No. 2015-02 is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. We are still evaluating the impact of our adoption of ASU No. 2015-02.

On April 7, 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. ASU No. 2015-03 changes the presentation of debt issuance costs in financial statements. The new standard requires entities to present debt issuance costs as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs is reported as interest expense. ASU No. 2015-03 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015, and interim periods beginning after December 15, 2016. Early adoption is allowed for all entities for financial statements that have not been previously issued. Entities would apply the new guidance retrospectively to all prior periods. We do not expect the adoption of ASU No. 2015-03 to have a material impact on our financial statements or disclosures.

Table of Contents

3. Acquisitions

Third Party Acquisition

On October 1, 2014, we completed an acquisition of oil and natural gas properties in the Stroud field located in Lincoln and Creek Counties, Oklahoma for a purchase price of $38.0 million, subject to customary purchase price adjustments (the October 2014 Acquisition) from an unrelated third party. We paid total cash consideration of $38.2 million at closing. The October 2014 Acquisition was effective September 1, 2014. In January 2015, we paid $0.2 million in cash to the seller related to post-closing adjustments to the purchase price. We financed the acquisition with borrowings under our revolving credit facility (Note 7).

The October 2014 Acquisition was accounted for under the acquisition method of accounting, whereby the purchase price was allocated to the assets acquired and liabilities assumed based on their fair values, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (or shortfall of purchase price versus net fair value recorded as bargain purchase). Based on the purchase price allocation for October 2014 Acquisition, no goodwill or bargain purchase was recognized. The cash consideration paid for the October 2014 Acquisition and the assets and liabilities recognized are presented in the table below (in thousands, except for per unit amounts):

Property and equipment, net	$	38,848
Asset retirement obligations		(691)
Net assets	$	38,157

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties included estimates of: (i) reserves, including risk adjustments for probable and possible reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by our management at the time of the valuation and are subject to change.

The following unaudited pro forma information shows the pro forma effects of the October 2014 Acquisition. The unaudited pro forma information assumes the transaction occurred on January 1, 2014. The pro forma results of operations have been prepared by adjusting our historical results to include the historical results of the acquired assets based on information provided by the seller, our knowledge of the acquired properties and the impact of our purchase price allocation. We believe the assumptions used provide a reasonable basis for reflecting the pro forma significant effects directly attributable to the acquisition. The pro forma results of operations do not include any cost savings or other synergies that may result from the October 2014 Acquisition or any estimated costs that have been or will be incurred to integrate the assets. The following unaudited pro forma information does not purport to represent what our results of operations would have been if such acquisition had occurred on January 1, 2014 (in thousands).

		Three Months Ended June 30, 2014		Six Months Ended June 30, 2014
Total revenues	$	19,770	$	48,113
Net income (loss) available to unitholders		(6,049)		(2,052)

Basic and diluted net income (loss) per unit	(0.23)	(0.08)

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,

Table of Contents

including the current portion, approximates fair value, as interest rates are variable based on prevailing market rates and are therefore considered Level 1 instruments. Our financial and non-financial assets and liabilities that are measured on a recurring basis are measured and reported at fair value.

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

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

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

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

We utilize the most observable inputs available for the valuation technique used. The financial assets and liabilities are classified in their entirety based on the lowest level of input that is of significance to the fair value measurement. The following table describes, by level within the hierarchy, the fair value of our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014 (in thousands).

	Level 1	Level 2	Level 3	Total
June 30, 2015				
Assets:				
Commodity derivative instruments	$	$ 69,246	$	$ 69,246
Liabilities:				
Commodity derivative instruments		877		877
Interest rate derivative instruments		3,741		3,741
December 31, 2014				
Assets:				
Commodity derivative instruments	$	$ 84,464	$	$ 84,464
Liabilities:				
Commodity derivative instruments		788		788
Interest rate derivative instruments		3,144		3,144

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, 2015	December 31, 2014
Oil and natural gas properties (successful efforts method)	$ 970,906	$ 954,819
Unproved properties	1,220	1,235
Other property and equipment	272	272
	972,398	956,326
Accumulated depletion, depreciation and impairment	(559,893)	(506,368)
Total property and equipment, net	$ 412,505	$ 449,958

We recorded $8.7 million of depletion and depreciation expense for each of the three months ended June 30, 2015 and 2014. We recorded $17.6 million and $17.1 million of depletion and depreciation expense for the six months ended June 30, 2015 and 2014, respectively.

We perform an impairment analysis of our oil and natural gas properties on a quarterly basis due to the volatility in commodity prices. For the three months ended June 30, 2015, we recorded a total non-cash impairment charge of $0.3 million to impair the value of our proved oil and natural gas properties in the Mid-Continent region. We did not record any impairment charges in the three months ended June 30, 2014. For the six months ended June 30, 2015, we recorded a total non-cash impairment charge of $36.0 million to impair the value of our proved oil and natural gas properties in the Permian Basin, Gulf Coast, and the Mid-Continent regions. This impairment charge reduced the regions carrying values to an estimated fair value of $411.3 million as of June 30, 2015. We did not record any impairment charges in the six months ended June 30, 2014.

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

These asset impairments have no impact on cash flows, liquidity positions, or debt covenants. If future oil or natural gas prices decline further, the estimated undiscounted future cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for our

properties and a non-cash impairment charge may be required to be recognized in future periods.

Table of Contents

6. Asset Retirement Obligations

The following is a summary of our asset retirement obligations as of and for the six months ended June 30, 2015 (in thousands):

Beginning of period	$	41,604
Acquisitions		13
Revisions to previous estimates		5
Liabilities incurred		106
Liabilities settled		(46)
Accretion expense		1,029
End of period		42,711
Current portion of asset retirement obligations		(2,153)
Asset retirement obligations non-current	$	40,558

7. Long-Term Debt

Credit Agreement

We, as guarantor, and our wholly owned subsidiary, OLLC, as borrower, are parties to a five-year, $750 million senior secured revolving credit facility, as amended (the Credit Agreement), that matures on October 1, 2019. The Intercreditor Agreement (as described below) limits the amount of indebtedness outstanding at any time under the Credit Agreement (including undrawn amounts under letters of credit) to an amount not to exceed $500 million in the aggregate. 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 $244 million as of June 30, 2015. Our borrowing base, which is primarily based on the estimated value of our oil, natural gas liquids (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, 2015, we were in compliance with all covenants contained in the Credit Agreement.

In May 2015, we entered into the Fifth Amendment (Fifth Credit Agreement Amendment) to our Credit Agreement. The Fifth Credit Agreement Amendment, among other things, (i) increased the interest rate margins applicable to the loans with margins ranging from 2.00% to 3.10% for Eurodollar loans, and from 1.00% to 2.10% for base rate loans, in each case based on utilization of the credit facility, (ii) increased the commitment fee applicable to the unused portion of the borrowing base with amounts ranging from 0.375% to 0.800% based on utilization of the credit facility, (iii) restricted the payments of distributions to $10.6 million through September 30, 2015; however, after October 1, 2015, distributions are subject to a minimum of 15% availability under a conforming borrowing base amount, and (iv) decreased the borrowing base to $245.0 million. Pursuant to the amendment, the borrowing base began to decrease in the amount of $1.0 million per month, beginning in June 2015 and continuing until the next redetermination of the borrowing base in the fall of 2015. The borrowing base of the Credit Agreement will revert to $195.0 million upon the earlier of November 1, 2015 and a termination of the Merger Agreement.

Term Loan Agreement

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

The Term Loan Agreement contains various covenants and restrictive provisions as described in our 2014 Annual Report. As of June 30, 2015, we were in compliance with the leverage and current ratios contained in our Term Loan Agreement. We are required to test the asset coverage ratio at specified intervals as described in the Term Loan Agreement, including during the redetermination of our borrowing base under our Credit Agreement. We were not in compliance with the asset coverage ratio during the borrowing base redetermination in the second quarter of 2015; however, we received a waiver from our lender under the Term Loan Agreement for the asset coverage ratio covenant.

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.

In May 2015, we entered into the Fifth Amendment (Fifth Term Loan Amendment) to our Term Loan Agreement. The Fifth Term Loan Amendment, among other things, amended the Term Loan Agreement to (i) increase the interest rate margins applicable to the loan with margins for Eurodollar loans and Alternate Base Rate loans increasing to 9.50% and 8.50%, respectfully, after September 30, 2015, and (ii) restrict the payments of distributions to $10.6 million through September 30, 2015; however, after October 1, 2015, distributions are subject to having a minimum of 15% availability under a conforming borrowing base amount.

As of June 30, 2015, we had $285.0 million of outstanding debt and accrued interest was approximately $0.2 million. As of December 31, 2014, we had $280.0 million of outstanding debt and accrued interest was approximately $0.2 million.

Interest expense for the three months ended June 30, 2015 and 2014 was $3.1 million and $2.6 million, respectively. Interest expense for the six months ended June 30, 2015 and 2014 was $5.9 million and $5.1 million, respectively. As of June 30, 2015 and December 31, 2014, our weighted average interest rate on our outstanding indebtedness was 5.27% and 3.81%, 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.

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.

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.

12

Table of Contents

At June 30, 2015, we had the following open commodity derivative contracts:

	Index	2015	2016	2017	2018
Natural gas positions					
Price swaps (MMBtu)	NYMEX-HH	2,688,648	5,433,888	5,045,760	3,452,172
Weighted average price		$ 5.75	$ 4.29	$ 4.61	$ 4.05
Basis swaps (MMBtu)	(1)	2,601,807	2,877,047		
Weighted average price		$ (0.1666)	$ (0.1115)	$	$
Oil positions					
Price swaps (Bbl)	NYMEX-WTI	360,683	610,131	473,698	562,524
Weighted average price		$ 93.42	$ 87.27	$ 84.34	$ 82.26
Basis swaps (Bbl)	Argus-	187,000	364,800		
Weighted average price	Midland-Cushing	$ (3.2500)	$ (1.0500)	$	$
NGL positions					
Price swaps (Bbl)	Mont Belvieu	112,877			
Weighted average price		$ 34.45	$	$	$

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

At December 31, 2014, we had the following open commodity derivative contracts:

	Index	2015	2016	2017	2018
Natural gas positions					
Price swaps (MMBtu)	NYMEX-HH	5,500,236	5,433,888	5,045,760	2,374,800
Weighted average price		$ 5.72	$ 4.29	$ 4.61	$ 4.28
Basis swaps (MMBtu)	(1)	5,326,559	2,877,047		
Weighted average price		$ (0.1661)	$ (0.1115)	$	$
Oil positions					
Price swaps (Bbl)	NYMEX-WTI	757,321	610,131	473,698	562,524
Weighted average price		$ 93.16	$ 87.27	$ 84.34	$ 82.26
Basis swaps (Bbl)	Argus-	397,035			
Weighted average price	Midland-Cushing	$ (3.4087)	$	$	$
NGL positions					
Price swaps (Bbl)	Mont Belvieu	236,149			
Weighted average price		$ 34.46	$	$	$

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

At June 30, 2015, we had the following interest rate swap derivative contracts (in thousands):

Table of Contents

Effective	Maturity	Notional Amount	Average %	Index
February 2015	February 2017	75,000	1.72500%	LIBOR
February 2015	February 2017	75,000	1.72750%	LIBOR
June 2015	June 2017	70,000	1.42750%	LIBOR

At December 31, 2014, 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, 2015			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$	$ 2,781	$ 960
Gross fair value			2,781	960
Netting arrangements				
Net recorded fair value	$	$	$ 2,781	$ 960
Sale of natural gas production				
Price swaps	$ 10,753	$ 11,022	$	$
Basis swaps			184	89
Sale of crude oil production				
Price swaps	19,662	26,137		
Basis swaps		7	599	12
Sale of NGLs				
Price swaps	1,672			
Gross fair value	32,087	37,166	783	101
Netting arrangements		(7)		(7)
Net recorded fair value	$ 32,087	$ 37,159	$ 783	$ 94

Table of Contents

	As of December 31, 2014			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$	$ 2,327	$ 817
Gross fair value			2,327	817
Netting arrangements				
Net recorded fair value	$	$	$ 2,327	$ 817
Sale of natural gas production				
Price swaps	$ 14,732	$ 9,170	$	$
Basis swaps	1		286	232
Sale of crude oil production				
Price swaps	27,544	29,370		
Basis swaps			271	
Sale of NGLs				
Price swaps	3,648			
Gross fair value	45,925	38,540	557	232
Netting arrangements	(1)		(1)	
Net recorded fair value	$ 45,924	$ 38,540	$ 556	$ 232

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,	
	2015	2014	2015	2014
Commodity derivatives (revenue)	$ (8,927)	$ (13,328)	$ 9,755	$ (18,950)
Interest rate derivatives (other income (expense), net)	(322)	(1,128)	(1,673)	(1,422)

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, 2015, 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 30.5% of our outstanding common units, representing their limited partner interest in us. As of June 30, 2015, 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.

Table of Contents

As more fully described in our 2014 Annual Report, 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 converted the remaining 4,480,000 subordinated units on a one-for-one basis into common units pursuant to the terms of our partnership agreement on February 13, 2015.

Contracts with our General Partner and its Affiliates

As more fully described in our 2014 Annual Report, we have entered into agreements with our general partner and its affiliates. For each of the three months ended June 30, 2015 and 2014, we paid Lime Rock Management approximately $0.4 million either directly or indirectly related to these agreements. For the six months ended June 30, 2015 and 2014, we paid Lime Rock Management approximately $0.8 million and $0.6 million either directly or indirectly related to these agreements, respectively.

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, 2015 are included below (in thousands):

	ServCo	Lime Rock Resources	Total
Balance as of December 31, 2014	$ 5,436	$ 261	$ 5,697
Expenditures	(90,596)	(263)	(90,859)
Cash paid for expenditures	93,084		93,084
Revenues and other	(6,468)	2	(6,466)
Balance as of June 30, 2015	$ 1,456	$	$ 1,456`

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, 2015, our general partner and its affiliates held 8,569,600 of our common units and 22,400 general partner units. During the six months ended June 30, 2015 and 2014, we paid cash distributions of $19.2 million and $26.0 million, respectively, to all unitholders as of the respective record dates.

We announced our second quarter 2015 distribution on July 17, 2015 as discussed in Note 15.

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, subject to limitations as described in the Merger Agreement (described in Note 1). 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 of 1933, as amended, (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. During the six months ended June 30, 2015, we did not sell common units under the ATM Program.

Table of Contents

Units Outstanding

As of June 30, 2015, we had 28,074,433 common units and 22,400 general partner units outstanding. As of June 30, 2015, Fund I owned 8,569,600 common units, representing a 30.5% limited partner interest in us.

General Partner Allocation of Loss

In accordance with our partnership agreement, the allocation of net loss cannot cause a unitholder to have a deficit balance. Deficit balances are carried by our general partner until net income is generated in a taxable period. Our general partner will recover losses from net income generated prior to the net income being allocated to the remaining unitholders.

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,	
	2015	2014	2015	2014
Net income (loss) available to unitholders	$ (22,314)	$ (7,337)	$ (47,250)	$ (4,643)
Less: General partner s interest in net (income) loss	7,595	7	9,434	4
Limited partners interest in net income (loss)	$ (14,719)	$ (7,330)	$ (37,816)	$ (4,639)
Weighted average limited partner units outstanding:				
Common units	28,074	21,121	26,984	20,376
Subordinated units		5,612	1,089	6,163
Total	28,074	26,733	28,073	26,539
Net income (loss) per limited partner unit (basic and diluted)	$ (0.52)	$ (0.27)	$ (1.35)	$ (0.17)

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 interest in net income (loss), by the weighted average number of common units and subordinated units outstanding as of June 30, 2015 and 2014. The aggregate number of common units outstanding was 28,074,433, as of June 30, 2015. We did not have any subordinated units outstanding as of June 30, 2015. The aggregate number of common units and subordinated units outstanding was 22,674,390 and 4,480,000, respectively, as of June 30, 2014.

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, 2015, there were 1,025,013 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, 2015 is presented below:

	Number of Non-vested Restricted Units	Weighted Average Grant-date Fair Value
Non-vested restricted units at December 31, 2014	361,957	$ 9.38
Granted	12,542	5.98
Vested	(32,066)	12.53
Forfeited		
Non-vested restricted units at June 30, 2015	342,433	8.96

As of June 30, 2015, there was approximately $2.3 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 2.1 years. There were 132,554 vested restricted units as of June 30, 2015. At the close of the Merger, all unvested restricted units will vest immediately.

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. 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. Commitments and Contingencies

Litigation

The following class action lawsuits (the Lawsuits) were filed in connection with the merger by purported LRR Energy, L.P. unitholders against us, our General Partner, our Board, Vanguard, Merger Sub and the other parties to the Merger Agreement (the Defendants):

- *Barry Miller v. LRR Energy, L.P. et al., Case No. 11087-VCG*, filed in the Court of Chancery of the State of Delaware on June 3, 2015 (Miller Lawsuit)

- *Christopher Tiberio v. LRR Energy, L.P. et al., Cause No. 2015-39864*, filed in the 334th Judicial District Court of Harris County, Texas on July 10, 2015 (Tiberio Lawsuit)

- *Eddie Hammond v. LRR Energy, L.P. et al., Cause No. 2015-40154*, filed in the 295th Judicial District Court of Harris County, Texas on July 13, 2015 (Hammond Lawsuit)

- *Ronald Krieger v. LRR Energy, L.P. et al., Civil Action No. 4:15-cv-2017*, filed in the United States District Court for the Southern District of Texas on July 14, 2015 (Krieger Lawsuit)

On July 17, 2015, the Krieger Lawsuit was voluntarily dismissed without prejudice. On July 23, 2015, the Miller Lawsuit was also voluntarily dismissed without prejudice. On July 28, 2015, the Tiberio Lawsuit and the Hammond Lawsuit were both nonsuited without prejudice.

Prior to their dismissals, the Lawsuits alleged that the merger (a) provided inadequate consideration to our unitholders and alleged that we and our Board breached certain fiduciary duties to the common unitholders by accepting such inadequate

Table of Contents

consideration and (b) contained contractual terms that would dissuade other potential merger partners from making alternative proposals for us, including, but not limited to, the requirement that certain of our unitholders enter into a voting and support agreement, adoption of an allegedly unreasonable no solicitation clause, the notice provisions, and allowing our Board to withdraw its favorable recommendation only under extremely limited circumstances.

Prior to their dismissals, the Tiberio, Hammond, and Krieger Lawsuits also allege that the Vanguard Form S-4 Registration Statement filed with the SEC on June 16, 2015 failed to make all material disclosures and contained materially misleading statements about the merger in violation of Sections 14(a) and 20(a) of the Securities and Exchange Act of 1934 and SEC Rule 14a-9.

The Lawsuits sought to be certified as class actions, and asked that the court, among other relief, enjoin the merger, or rescind the merger in the event it was consummated, and award damages, attorneys fees and costs. We and the other Defendants believed the Lawsuits were without merit, denied the allegations in their entirety and requested voluntary dismissal from each of the plaintiffs. They were each dismissed. Therefore, neither we nor our General Partner is currently a party to any material legal proceedings.

15. Subsequent Events

Unit Distribution

On July 17, 2015, we announced that the Board declared a cash distribution for the second quarter of 2015 of $0.1875 per outstanding unit, or $0.75 on an annualized basis. The distribution will be paid on August 14, 2015 to all unitholders of record as of the close of business on July 31, 2015. The aggregate amount of the distribution will be $5.3 million.

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, anticipate, target, continue, potential, should, could and similar terms and phrases. Although we believe that

the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties some of which are beyond our control. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the risk factors described in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2014 (2014 Annual Report) and our Quarterly Report on Form 10-Q for the three months ended March 31, 2015 which 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 risk that oil and natural gas prices remain depressed for a prolonged period of time;*
- *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 contained in the instruments governing our existing indebtedness;*
- *the availability of pipelines, transportation and gathering systems and processing facilities owned by third parties;*
- *electronic, cyber, and physical security breaches;*

Table of Contents

- *general economic conditions; and*
- *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.

On April 20, 2015, we and Vanguard Natural Resources, LLC (Vanguard) announced the signing of a Purchase Agreement and Plan of Merger (the Merger Agreement) pursuant to which a subsidiary of Vanguard will merge into the Partnership, and at the same time, Vanguard will acquire LRE GP, LLC (our General Partner). As a result of the transaction, we and our General Partner will become wholly owned subsidiaries of Vanguard. The transaction, which has been approved by the boards of directors of both companies, including the Conflicts Committee of our General Partner s board of directors, is expected to be a tax-free unit-for-unit transaction with an exchange ratio of 0.550 Vanguard common units for each of our common units issued and outstanding immediately prior to the effective time of the merger. In addition, Vanguard will acquire all of the limited liability company interests in our General Partner in exchange for 12,320 Vanguard common units. The special meeting of unitholders to approve the Merger Agreement is scheduled to occur on September 10, 2015. Our unitholders of record at the close of business on July 24, 2015 will be entitled to receive notice of the special meeting and vote at the special meeting. We expect the transaction to close in the third quarter of 2015.

Acquisition of Properties

On October 1, 2014, we completed an acquisition of oil and natural gas properties in the Stroud field located in Lincoln and Creek Counties, Oklahoma for a purchase price of $38.0 million (the October 2014 Acquisition) from an unrelated third party. The October 2014 Acquisition was effective September 1, 2014. We financed the acquisition with borrowings under our Credit Agreement. In January 2015, we paid $0.2 million in cash to the seller related to post-closing adjustments to the purchase price.

Results of Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues (in thousands):				
Oil sales	$ 14,227	$ 20,354	$ 26,291	$ 40,510
Natural gas sales	3,720	7,565	7,986	15,664
Natural gas liquids sales	1,661	2,760	2,832	6,124
Gain (loss) on commodity derivative instruments, net	(8,927)	(13,328)	9,755	(18,950)
Other income	26	40	55	71
Total revenues	10,707	17,391	46,919	43,419

Table of Contents

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Expenses (in thousands):				
Lease operating expense	6,008	6,829	12,780	12,664
Production and ad valorem taxes	1,482	2,248	2,748	4,648
Depletion and depreciation	8,694	8,680	17,574	17,145
Impairment of oil and natural gas properties	256		35,962	
General and administrative expense	12,673	2,699	16,464	5,881
Interest expense	3,120	2,575	5,889	5,116
Loss (gain) on interest rate derivative instruments, net	322	1,128	1,673	1,422
Production:				
Oil (MBbls)	270	216	545	434
Natural gas (MMcf)	1,470	1,666	2,988	3,288
NGLs (MBbls)	99	90	189	175
Total (MBoe)	614	584	1,232	1,157
Average net production (Boe/d)	6,747	6,418	6,807	6,392
Average sales price:				
Oil (per Bbl):				
Sales price	$ 52.69	$ 94.23	$ 48.24	$ 93.34
Effect of settled commodity derivative instruments	23.74	(3.50)	27.77	(2.14)
Realized sales price	$ 76.43	$ 90.73	$ 76.01	$ 91.20
Natural gas (per Mcf):				
Sales price	$ 2.53	$ 4.54	$ 2.67	$ 4.76
Effect of settled commodity derivative instruments	2.77	0.71	2.61	0.62
Realized sales price	$ 5.30	$ 5.25	$ 5.28	$ 5.38
NGLs (per Bbl):				
Sales price	$ 16.78	$ 30.67	$ 14.98	$ 34.99
Effect of settled commodity derivative instruments	9.41	(1.81)	9.94	(2.77)
Realized sales price	$ 26.19	$ 28.86	$ 24.92	$ 32.22
Average unit cost per Boe:				
Lease operating expenses	$ 9.79	$ 11.70	$ 10.37	$ 10.95
Production and ad valorem taxes	2.41	3.85	2.23	4.02
Depletion and depreciation	14.16	14.87	14.26	14.82
General and administrative expenses	20.64	4.62	13.36	5.08

Our Results for the Three Months Ended June 30, 2015 Compared to the Three Months Ended June 30, 2014

We recorded net loss of $22.3 million for the three months ended June 30, 2015 compared to net loss of $7.3 million for the three months ended June 30, 2014, primarily related to decreased revenues due to lower commodity prices as well as increased general and administrative expenses incurred due to the transaction costs associated with the merger with Vanguard. 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, 2014 and June 30, 2015 follows (in thousands):

Table of Contents

Oil, natural gas and NGL revenues-prior period	$	30,679
Increase (decrease)		
Price realization		
Oil		(8,973)
Natural gas		(3,348)
NGLs		(1,250)
Sales volumes		
Oil		2,845
Natural gas		(496)
NGLs		151
Oil, natural gas and NGL revenues-current period	$	19,608

Sales revenues decreased from $30.7 million for the three months ended June 30, 2014 to $19.6 million for the three months ended June 30, 2015, primarily due to lower commodity price realizations offset by higher oil and NGL sales volumes. Sales revenues for the three months ended June 30, 2015 consisted of oil sales of $14.2 million, natural gas sales of $3.7 million and NGL sales of $1.7 million. 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.

Our production volumes for the three months ended June 30, 2015 included 369 MBbls of oil and NGLs and 1,470 MMcf of natural gas, or 4,055 Bbl/d of oil and NGLs and 16,154 Mcf/d of natural gas. On an equivalent basis, production for the period was 614 MBoe, or 6,747 Boe/d. 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. Oil production for the three months ended June 30, 2015 increased primarily due to the October 2014 Acquisition of the Stroud field and the continued positive drilling results at the Red Lake field.

Our average sales price per Bbl for oil and NGLs for the three months ended June 30, 2015, excluding the effect of commodity derivative contracts, was $52.69 and $16.78, respectively. Our average sales price per Mcf of natural gas for the three months ended June 30, 2015, excluding the effect of commodity derivative contracts, was $2.53. 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.

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, 2015 of approximately $8.9 million, which is comprised of positive net cash settlements and amortization of purchases of approximately $11.4 million and decreases in the fair value of derivatives of approximately $20.3 million. For the three months ended June 30, 2014, we recorded a net loss from our commodity hedging program 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. Volatility in commodity prices has had a significant impact on our gains and losses on commodity derivative contracts.

Lease Operating Expense. Our lease operating expenses were approximately $6.0 million, or $9.79 per Boe, for the three months ended June 30, 2015 compared to approximately $6.8 million, or $11.70 per Boe, for the three months ended June 30, 2014. The primary driver of the decreased lease operating expenses was as a result of lower workover expenses and salt water disposal costs.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $1.5 million, or $2.41 per Boe, for the three months ended June 30, 2015 compared to approximately $2.2 million, or $3.85 per Boe, for the three months ended June 30, 2014. Production taxes accounted for approximately $1.4 million and ad valorem taxes for $0.1 million of the total taxes recorded during the three months ended June 30, 2015. Production taxes accounted for approximately $2.1 million and ad valorem taxes for $0.1 million of the total taxes recorded during the three months ended June 30, 2014. Production taxes for the three months ended June 30, 2015 declined from the same period in 2014 primarily due to lower commodity price realizations and the lower net taxable value associated with the production taxes.

Table of Contents

Depletion and Depreciation. Our depletion and depreciation expense was $8.7 million, or $14.16 per Boe, for the three months ended June 30, 2015 compared to $8.7 million, or $14.87 per Boe, for the three months ended June 30, 2014.

Impairment of Oil and Natural Gas Properties. For the three months ended June 30, 2015, we recorded a total non-cash impairment charge of $0.3 million to impair the value of our proved oil and natural gas properties in the Mid-Continent region. We did not record an impairment charge in the three months ended June 30, 2014. If future oil or natural gas prices or reserves decline further, 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, 2015, the NYMEX-WTI oil spot price was $47.12 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.77 per MMBtu.

General and Administrative Expenses. Our general and administrative expenses were approximately $12.7 million, or $20.64 per Boe, for the three months ended June 30, 2015 compared to approximately $2.7 million, or $4.62 per Boe, for the three months ended June 30, 2014. The increase in general and administrative expense is primarily related to expenses associated with legal and consulting fees and severance payments relating to the merger with Vanguard of $8.9 million.

Interest Expense. Our interest expense is comprised of interest on our credit facility and term loan and amortization of debt issuance costs. Interest expense was approximately $3.1 million and $2.6 million for the three months ended June 30, 2015 and 2014, respectively. The increase in interest expense is primarily related to a higher debt balances in 2015.

Effects of Interest Rate Derivatives. Loss on interest rate derivative contracts, net, was approximately $0.3 million for the three months ended June 30, 2015, including $0.7 million in negative cash settlements and $0.4 million in increases in fair value of the derivatives. Loss on interest rate derivative contracts, net, was approximately $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.

Our Results for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014

We recorded a net loss of $47.3 million for the six months ended June 30, 2015 compared to a net loss of $4.6 million for the six months ended June 30, 2014, primarily related to the impairment charge of $36.0 million and increased general and administrative expenses incurred due to the transaction costs associated with the merger with Vanguard offset by higher total revenues. 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, 2014 and June 30, 2015 follows (in thousands):

Oil, natural gas and NGL revenues-prior period	$	62,298
Increase (decrease)		
Price realization		
Oil		(19,573)
Natural gas		(6,878)
NGLs		(3,502)
Sales volumes		
Oil		5,355
Natural gas		(801)
NGLs		210
Oil, natural gas and NGL revenues-current period	$	37,109

Sales revenues decreased from $62.3 million for the six months ended June 30, 2014 to $37.1 million for the six months ended June 30, 2015, primarily due to lower commodity price realizations offset by higher oil and NGL sales volumes. Sales revenues for the six months ended June 30, 2015 consisted of oil sales of $26.3 million, natural

Table of Contents

gas sales of $8.0 million and NGL sales of $2.8 million. 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.

Our production volumes for the six months ended June 30, 2015 included 734 MBbls of oil and NGLs and 2,988 MMcf of natural gas, or 4,055 Bbl/d of oil and NGLs and 16,508 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,232 MBoe, or 6,807 Boe/d. 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. Oil production for the six months ended June 30, 2015 increased primarily due to the October 2014 Acquisition of the Stroud field and the continued positive drilling results at the Red Lake field.

Our average sales price per Bbl for oil and NGLs for the six months ended June 30, 2015, excluding the effect of commodity derivative contracts, was $48.24 and $14.98, respectively. Our average sales price per Mcf of natural gas for the six months ended June 30, 2015, excluding the effect of commodity derivative contracts, was $2.67. 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.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, we recorded a net gain from our commodity hedging program for the six months ended June 30, 2015 of $9.8 million, which was comprised of positive net cash settlements and amortization of purchases of approximately $24.8 million and declines in the fair value of derivatives of approximately $15.0 million. For the six months ended June 30, 2014, we recorded a net loss from our commodity hedging program 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. 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 $12.8 million, or $10.37 per Boe, for the six months ended June 30, 2015 compared to $12.7 million, or $10.95 per Boe, for the six months ended June 30, 2014.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were $2.7 million, or $2.23 per Boe, for the six months ended June 30, 2015 compared to $4.6 million, or $4.02 per Boe, for the six months ended June 30, 2014. Production taxes accounted for approximately $2.5 million and ad valorem taxes for $0.2 million of the total taxes recorded during the six months ended June 30, 2015. 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 for the six months ended June 30, 2015 declined from the same period in 2014 primarily due to lower commodity price realizations and the lower net taxable value associated with the production taxes.

Depletion and Depreciation. Our depletion and depreciation expense was $17.6 million, or $14.26 per Boe, for the six months ended June 30, 2015 compared to $17.1 million, or $14.82 per Boe, for the six months ended June 30, 2014.

Impairment of Oil and Natural Gas Properties. For the six months ended June 30, 2015, we recorded a total non-cash impairment charge of $36.0 million to impair the value of our proved oil and natural gas properties in the Permian Basin, Gulf Coast, and the Mid-Continent regions. We did not record an impairment charge in the six months ended June 30, 2014. If future oil or natural gas prices or reserves decline further, 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, 2015, the NYMEX-WTI oil spot price was $47.12 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.77 per MMBtu.

General and Administrative Expenses. Our general and administrative expenses were $16.5 million, or $13.36 per Boe, for the six months ended June 30, 2015 compared to $5.9 million, or $5.08 per Boe, for the six months ended June 30, 2014. The increase in general and administrative expense is primarily related to expenses associated with legal and consulting fees and severance payments relating to the merger with Vanguard of $9.1 million.

Table of Contents

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 $5.9 million and $5.1 million for the six months ended June 30, 2015 and 2014, respectively. The increase in interest expense is primarily related to higher debt balances during 2015.

Effects of Interest Rate Derivatives. Loss on interest rate derivative contracts, net, was $1.7 million for the six months ended June 30, 2015, including $1.1 million in negative cash settlements and $0.6 million in declines in fair value of the 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.

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 (benefit);
- 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 expenditures.

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.

Table of Contents

Our Adjusted EBITDA for the three months ended June 30, 2015 and 2014 was $20.5 million and $19.6 million, respectively. Our Adjusted EBITDA for the six months ended June 30, 2015 and 2014 was $40.2 million and $40.7 million, respectively.

Our Distributable Cash Flow for the three months ended June 30, 2015 and 2014 was $12.0 million and $11.8 million, respectively. Our Distributable Cash Flow for the six months ended June 30, 2015 and 2014 was $23.9 million and $25.2 million, respectively.

Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Income

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	**2014**	**2015**	**2014**
(in thousands)				
Net income (loss)	$ (22,314)	$ (7,337)	$ (47,250)	$ (4,643)
Income tax expense (benefit)	(56)	38	(18)	112
Interest expense-net, including loss (gain) on interest rate derivative instruments, net	3,442	3,703	7,562	6,538
Depletion and depreciation	8,694	8,680	17,574	17,145
Accretion of asset retirement obligations	518	510	1,029	1,013
Amortization of equity awards	493	249	838	534
Loss (gain) on settlement of asset retirement obligations	4	21	68	61
Loss (gain) on commodity derivative instruments, net	8,927	13,328	(9,755)	18,950
Commodity derivative instrument net cash settlements	11,542	444	25,061	967
Impairment of oil and natural gas properties	256		35,962	
Other non-recurring items(1)	8,948		9,098	
Adjusted EBITDA	$ 20,454	$ 19,636	$ 40,169	$ 40,677
Adjusted EBITDA	20,454	19,636	40,169	40,677
Cash income tax expense	(47)	(44)	(85)	(88)
Cash interest expense	(3,695)	(2,757)	(6,638)	(5,401)
Estimated maintenance capital (2)	(4,750)	(5,000)	(9,500)	(10,000)
Distributable cash flow	$ 11,962	$ 11,835	$ 23,946	$ 25,188

(1) Includes one-time costs associated with the merger with Vanguard including consulting and legal fees and severance payments.

(2) Estimated maintenance capital expenditures as defined by our partnership agreement represents 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, to meet our indebtedness obligations, to refinance our indebtedness, to meet our collateral requirements, or to pay our distributions 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.

In February 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, subject to limitations as described in the Merger Agreement. Our second lien term loan requires that 50% of the net cash proceeds from any equity offering be used to repay borrowings

Table of Contents

outstanding under the term loan. 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, 2015, we did not sell common units under the ATM Program.

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.

Based on the number of common units and general partner units outstanding as of July 31, 2015, quarterly distributions to all of our unitholders at our current quarterly distribution rate would total $5.3 million. The Merger Agreement prohibits an increase in the distribution from the current quarterly rate.

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. If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures or further reduce distributions to unitholders.

Based upon current oil and natural gas price expectations and our commodity derivatives positions at June 30, 2015, which cover 80% of our estimated production from total proved developed producing reserves, we anticipate that our cash on hand and cash flow from operations will provide us sufficient working capital to fund our total planned 2015 capital expenditures and cash distributions.

We expect to spend $19.0 million in total capital expenditures in 2015. Our 2015 budget consists entirely of maintenance capital expenditures. We may further reduce our capital expenditure budget as we continue to monitor commodity prices and liquidity.

Credit Agreement

We, as guarantor, and our wholly owned subsidiary, OLLC, as borrower, are parties to a five-year, $750 million senior secured revolving credit facility, as amended (the Credit Agreement), that matures on October 1, 2019. The Intercreditor Agreement (as described below under Term Loan Agreement) limits the amount of indebtedness outstanding at any time under the Credit Agreement (including undrawn amounts under letters of credit) to an amount not to exceed $500.0 million in the aggregate. The Credit Agreement is reserve-based and we are permitted to borrow under our credit facility an amount up to the borrowing base. Our borrowing base, which is primarily

Table of Contents

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 and once during the interim periods at their sole discretion.

In the second quarter of 2015, primarily as a result of significantly lower commodity prices, our borrowing base was reduced to $245.0 million under an amendment to our Credit Agreement. The amendment is discussed in Note 7. Pursuant to the amendment, the borrowing base will decrease by $1.0 million per month beginning in June 2015 and continuing until the next borrowing base redetermination in November 2015. As of June 30, 2015, our borrowing base was $244 million.

If we fail to perform our obligations under the covenants described in our 2014 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, 2015, we were in compliance with our covenants contained in the Credit Agreement.

At June 30, 2015, we had $235.0 million of outstanding borrowings under our Credit Agreement and available borrowing capacity of $9.0 million. As of July 31, 2015, we had approximately $235.0 million of outstanding borrowings under our Credit Agreement and available borrowing capacity of approximately $8.0 million.

Term Loan Agreement

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

The Term Loan Agreement contains various covenants and restrictive provisions as described in our 2014 Annual Report. As of June 30, 2015, we were in compliance with the leverage and current ratios contained in our Term Loan Agreement. We are required to test the asset coverage ratio at specified intervals as described in the Term Loan Agreement, including during the redetermination of our borrowing base under our Credit Agreement. We were not in compliance with the asset coverage ratio during the borrowing base redetermination in the second quarter of 2015; however, we received a waiver from our lender in the Term Loan Agreement for the asset coverage ratio covenant. We entered into an amendment to our Term Loan Agreement as discussed in Note 7.

At June 30, 2015, we had $50.0 million of outstanding borrowings under our Term Loan Agreement and no available borrowing capacity.

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 in place as of June 30, 2015. The weighted average price is based on the swap price for oil, NGL and natural gas swaps. We use swaps 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**
2015	$ 93.42	1,960	$ 34.45	613	$ 5.75	14,612
2016	$ 87.27	1,672	$		$ 4.29	14,887
2017	$ 84.34	1,298	$		$ 4.61	13,824
2018	$ 82.26	1,541	$		$ 4.05	9,458

Table of Contents

The following table summarizes, for the periods presented, our natural gas basis swaps in place as of June 30, 2015. 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
2015	$ (0.2294)	5,771	$ (0.0967)	2,911	$ (0.1382)	4,636	$ (0.1343)	822
2016	$		$ (0.0810)	2,691	$ (0.1326)	4,408	$ (0.0975)	784

The following table summarizes, for the period presented, our oil basis swaps in place as of June 30, 2015. 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.

	Midland-Cushing	
Term	$/Bbl	Bbl/d
2015	$ (3.2500)	1,016
2016	$ (1.0500)	999

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,	
	2015	2014
Net cash provided by (used in):		
Operating activities	$ 35,954	$ 31,663
Investing activities	(17,606)	(17,029)
Financing activities	(14,243)	(16,180)

Operating Activities.

Net cash provided by operating activities was $36.0 million and $31.7 million for the six months ended June 30, 2015 and 2014, 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 $27.9 million and $49.5 million at June 30, 2015 and December 31, 2014, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled

$7.7 million and $3.6 million at June 30, 2015 and December 31, 2014, respectively.

Investing Activities.

Net cash used in investing activities was $17.6 million for the six months ended June 30, 2015, which primarily represented $17.4 million of additions to our property and equipment balances and $0.2 million related to post closing adjustments for the October 2014 acquisition of oil and gas natural properties. Net cash used in investing activities was $17.0 million for the six months ended June 30, 2014, which primarily represented additions to our property and equipment balances during the period.

Financing Activities.

Cash flows used in financing activities was $14.2 million for the six months ended June 30, 2015, and consisted

Table of Contents

of net borrowings under our revolving credit facility of approximately $5.0 million and distributions to unitholders of $19.2 million.

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.

Off-Balance Sheet Arrangements

As of June 30, 2015, 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 2014 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 2014 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, 2015.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2015 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

Table of Contents

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 Annual Report on Form 10-K for the year ended December 31, 2014 and in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 other than noted below.

Lawsuits have been filed challenging the merger and additional lawsuits may be filed in the future. Any injunctive relief, rescission, damages, or other adverse judgment could prevent the merger from occurring or could have a material adverse effect on us.

Alleged LRR Energy, L.P. unitholders have filed lawsuits challenging the merger against us, our General Partner, the Board, Vanguard, Merger Sub and the other parties to the merger agreement. Although each of these lawsuits has been dismissed or nonsuited, additional lawsuits challenging the merger may be filed in the future. For more information on these lawsuits, see Item 1. Legal Proceedings above.

One of the conditions to the completion of the merger is that no order, decree or injunction of any court or agency of competent jurisdiction shall be in effect, and no law shall have been enacted or adopted, that enjoins, prohibits or makes illegal consummation of any of the transactions contemplated by the merger agreement. A preliminary injunction could delay or jeopardize the completion of the merger, and an adverse judgment granting permanent injunctive relief could indefinitely enjoin completion of the merger. An adverse judgment for rescission or for monetary damages could have a material adverse effect on us.

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
2.1	Purchase Agreement and Plan of Merger, dated as of April 20, 2015, by and among Vanguard Natural Resources, LLC, Lighthouse Merger Sub, LLC, Lime Rock Management LP, Lime Rock Resources A, L.P., Lime Rock Resources B, L.P., Lime Rock Resources C, L.P., Lime Rock Resources II-A, L.P., Lime Rock Resources II-C, L.P., LRR Energy, L.P. and LRE GP, LLC (incorporated by reference to Exhibit 2.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on April 22, 2015).
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

Table of Contents

	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).
4.1	Registration Rights Agreement, dated as of April 20, 2015, by and among Vanguard Natural Resources, LLC, Lime Rock Management LP, Lime Rock Resources A, L.P., Lime Rock Resources B, L.P., Lime Rock Resources C, L.P., Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P (incorporated by reference to Exhibit 4.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on April 22, 2015).
4.2	Amended and Restated Registration Rights Agreement, dated as of May 21, 2015, by and among Vanguard Natural Resources, LLC, Lime Rock Management LP, Lime Rock Resources A, L.P., Lime Rock Resources B, L.P., Lime Rock Resources C, L.P., Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P (incorporated by reference to Exhibit 4.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on May 26, 2015).
10.1	Voting and Support Agreement, dated as of April 20, 2015, by and among Vanguard Natural Resources, LLC, Lime Rock Resources A, L.P., Lime Rock Resources B, L.P., Lime Rock Resources C, L.P., LRR Energy, L.P., LRE GP, LLC, Lime Rock Management LP, Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on April 22, 2015).
10.2	Fifth Amendment dated as of May 4, 2015 to Second Lien Credit Agreement dated as of July 22, 2011, 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 May 6, 2015).
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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

Table of Contents

	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 4, 2015

By: /s/ Eric Mullins
Eric Mullins
Co-Chief Executive Officer

Date: August 4, 2015

By: /s/ Jaime R. Casas
Jaime R. Casas
Vice President and Chief Financial Officer
(Principal Financial Officer)

Table of Contents

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Table of Contents

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101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith

** Submitted electronically herewith