LRR Energy, L.P.
Form 10-Q
August 14, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2012

OR

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

For the transition period from to .

Commission File Number: 001-35344

LRR Energy, L.P.

(Exact name of registrant as specified in its charter)

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

Telephone Number: (713) 292-9510

(Registrant s telephone number, including area code)

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

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

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

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

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

There were 15,708,474 Common Units, 6,720,000 Subordinated Units and 22,400 General Partner Units outstanding as of August 10, 2012. The Common Units trade on the New York Stock Exchange under the ticker symbol LRE .

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements.

LRR Energy, L.P.

Consolidated Condensed Balance Sheets

(Unaudited)

(in thousands, except unit amounts)

	Partnership			
		June 30, 2012		December 31, 2011
ASSETS				
Current assets:				
Cash and cash equivalents	$	4,656	$	1,513
Accounts receivable		8,452		12,924
Commodity derivative instruments		23,088		16,064
Prepaid expenses		662		578
Total current assets		36,858		31,079
Property and equipment (successful efforts method)		744,312		725,486
Accumulated depletion, depreciation and impairment		(286,745)		(263,931)
Total property and equipment, net		457,567		461,555
Commodity derivative instruments		32,057		27,015
Deferred financing costs, net of accumulated amortization		1,739		1,365
TOTAL ASSETS	$	528,221	$	521,014
LIABILITIES AND UNITHOLDERS EQUITY				
Current liabilities:				
Trade accounts payable	$		$	2,707
Accrued liabilities		3,910		2,746
Accrued capital cost		6,724		1,421
Commodity derivative instruments		565		186
Amounts due to affiliates		583		536
Interest rate derivative instruments		463		
Asset retirement obligations		371		359
Total current liabilities		12,616		7,955
Long-term liabilities:				
Commodity derivative instruments		620		
Interest rate derivative instruments		1,584		
Term loan		50,000		
Revolving credit facility		172,800		155,800
Asset retirement obligations		24,423		23,795
Deferred tax liabilities		140		35
Total long-term liabilities		249,567		179,630
Total liabilities		262,183		187,585
Unitholders equity:				
Predecessor s capital				61,926

General partner (22,400 units issued and outstanding as of June 30, 2012 and December 31, 2011)		432		438
Public common unitholders (10,608,000 units issued and outstanding as of June 30, 2012 and December 31, 2011)		187,025		189,537
Affiliated common unitholders (5,049,600 units issued and outstanding as of June 30, 2012 and December 31, 2011)		33,744		35,007
Subordinated unitholders (6,720,000 units issued and outstanding as of June 30, 2012 and December 31, 2011)		44,837		46,521
Total Unitholders Equity		266,038		333,429
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$	528,221	$	521,014

See accompanying notes to the unaudited consolidated/combined condensed financial statements

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LRR Energy, L.P.

Condensed Statements of Operations

(Unaudited)

(in thousands, except per unit amounts)

	Partnership Three Months Ended June 30, 2012 (consolidated)	Predecessor Three Months Ended June 30, 2011 (combined)	Partnership Six Months Ended June 30, 2012 (consolidated)	Predecessor Six Months Ended June 30, 2011 (combined)
Revenues:				
Oil sales	$ 15,555	$ 18,258	$ 30,913	$ 34,661
Natural gas sales	4,345	10,929	9,786	21,754
Natural gas liquids sales	2,713	4,422	5,770	7,758
Realized gain (loss) on commodity derivative instruments	6,820	(7,239)	12,068	41
Unrealized gain (loss) on commodity derivative instruments	10,997	16,124	11,008	(3,109)
Other income		41	3	80
Total revenues	40,430	42,535	69,548	61,185
Operating expenses:				
Lease operating expense	6,912	5,392	13,208	11,935
Production and ad valorem taxes	1,700	1,712	3,361	3,020
Depletion and depreciation	10,559	7,756	19,859	20,871
Impairment of oil and natural gas properties			3,093	
Accretion expense	361	372	717	744
(Gain) loss on settlement of asset retirement obligations	(10)		(108)	
Management fees		1,495		2,967
General and administrative expense	3,229	1,510	6,301	3,206
Total operating expenses	22,751	18,237	46,431	42,743
Operating income	17,679	24,298	23,117	18,442
Other income (expense), net				
Interest income				1
Interest expense	(1,332)	(273)	(2,460)	(559)
Realized loss on interest rate derivative instruments	(108)	(145)	(141)	(298)
Unrealized gain (loss) on interest rate derivative instruments	(2,852)	36	(2,047)	163
Other income (expense), net	(4,292)	(382)	(4,648)	(693)
Income before taxes	13,387	23,916	18,469	17,749
Income tax expense	(24)	(103)	(150)	(146)
Net income	$ 13,363	$ 23,813	$ 18,319	$ 17,603
Net income attributable to predecessor operations	(1,158)		(2,265)	
Net income available to unitholders	$ 12,205		$ 16,054	

Computation of net income per limited partner unit:				
General partners interest in net income	$	12	$	16
Limited partners interest in net income	$	12,193	$	16,038
Net income per limited partner unit (basic and diluted)	$	0.54	$	0.72
Weighted average number of limited partner units outstanding		22,428		22,425

See accompanying notes to the unaudited consolidated/combined condensed financial statements

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LRR Energy, L.P.

Consolidated Condensed Statement of Changes in Unitholders Equity

(Unaudited)

(in thousands)

					Limited Partners		
	Predecessors Capital	General Partner	Public Common	Affiliated Common	Affiliated Subordinated	Total
Balance, December 31, 2011	$ 61,926	$ 438	$ 189,537	$ 35,007	$ 46,521	$ 333,429
Contribution from predecessor	(4,869)	(6)	(2,752)	(1,303)	(1,731)	(10,661)
Book value of transferred properties contributed by predecessor	(59,322)					(59,322)
Amortization of equity awards			150			150
Distribution		(16)	(7,536)	(3,572)	(4,753)	(15,877)
Net income	2,265	16	7,626	3,612	4,800	18,319
Balance, June 30, 2012	$	$ 432	$ 187,025	$ 33,744	$ 44,837	$ 266,038

See accompanying notes to the unaudited consolidated/combined condensed financial statements

LRR Energy, L.P.

Condensed Statements of Cash Flows

(Unaudited)

(in thousands)

	Partnership Six Months Ended June 30, 2012 (consolidated)	Predecessor Six Months Ended June 30, 2011 (combined)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 18,319	$ 17,603
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion and depreciation	19,859	20,871
Impairment of oil and natural gas properties	3,093	
Unrealized (gain) loss on derivative instruments, net	(8,961)	2,946
Accretion expense	717	744
Amortization of equity awards	150	
Amortization of deferred financing costs and other	160	40
Gain on settlement of asset retirement obligations	(108)	
Purchase of derivative contracts	(59)	
Changes in operating assets and liabilities:		
Change in receivables	4,472	890
Change in prepaid expenses	(84)	(2,251)
Change in trade accounts payable and accrued liabilities	(1,438)	(1,567)
Change in amounts due from affiliates	47	(1,282)
Net cash provided by operating activities	36,167	37,994
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of oil and natural gas properties	(1,009)	(354)
Development of oil and natural gas properties	(12,607)	(26,158)
Disposition of oil and gas properties		2,967
Expenditures for other property and equipment	(16)	(40)
Net cash used in investing activities	(13,632)	(23,585)
CASH FLOWS FROM FINANCING ACTIVITIES		
Capital contributions		3,551
Contribution to Fund I	(4,869)	
Deferred financing costs	(532)	
Borrowings under revolving credit facility	67,000	
Payments on revolving credit facility	(50,000)	
Borrowings under term loan	50,000	
Distribution to Fund I	(65,114)	
Distributions to unitholders	(15,877)	(24,382)
Net cash used in financing activities	(19,392)	(20,831)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	3,143	(6,422)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	1,513	12,455
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 4,656	$ 6,033

Supplemental disclosure of non-cash items to reconcile investing and financing activities				
Property and equipment:				
Change in accrued capital costs	$	5,303	$	2,818
Asset retirement obligations		(166)		

See accompanying notes to the unaudited consolidated/combined condensed financial statements

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LRR Energy, L.P.

Notes to Consolidated/Combined Condensed Financial Statements

(unaudited)

1. Description of Business

LRR Energy, L.P. (we, us, our, or the Partnership) is a Delaware limited partnership formed in April 2011 by Lime Rock Management LP (Li Rock Management), an affiliate of Lime Rock Resources A, L.P. (LRR A), Lime Rock Resources B, L.P. (LRR B) and Lime Rock Resources C, L.P. (LRR C), to operate, acquire, exploit and develop producing oil and natural gas properties in North America with long-lived, predictable production profiles. As used herein, references to Fund I or predecessor refer collectively to LRR A, LRR B and LRR C. References to Lime Rock Resources refer collectively to LRR A, LRR B, LRR C, Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. The properties conveyed to us in connection with our initial public offering (IPO) (such conveyance described below) 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).

Prior to our IPO, Fund I owned 100% of the properties conveyed to us in connection with our IPO. At the closing of our IPO, we entered into a purchase, sale, contribution, conveyance and assumption agreement with Fund I pursuant to which Fund I sold and contributed to us specified oil and natural gas properties and related net profits interests and operations and certain commodity derivative contracts (the Partnership Properties). Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and our assumption of $27.3 million of LRR A s indebtedness.

After reviewing applicable accounting literature, we consider the Partnership Properties to be under common control with Fund I. We have presented the combined historical financial statements of Fund I as our historical financial statements because we believe them to be informative to our investors and representative of our management s ability to manage the Partnership Properties. The financial data and operations of Fund I are referred to herein as predecessor.

The following table presents the net assets conveyed by Fund I to the Partnership immediately prior to the closing of our IPO including the debt assumption (in thousands):

Property and equipment, net	$	400,056
Derivative instruments		36,705
Total assets	$	436,761
Long-term debt	$	27,251
Derivative instruments		476
Asset retirement obligations		22,673
Total liabilities	$	50,400
Net assets	$	386,361

On June 1, 2012, we completed an acquisition from Fund I of certain oil and natural gas properties (the Transferred Properties) located in the Permian Basin region of New Mexico and onshore Gulf Coast region of Texas for $65.1 million in cash (the Transaction). The Transaction was effective as of March 1, 2012. We funded the acquisition with borrowings under our revolving credit facility (Note 7). Please refer to Notes 2 and 3 regarding the recast of financial information for transactions between entities under common control.

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

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Property and equipment, net	$	60,365
Asset retirement obligations and other liabilities		(1,043)
Net assets	$	59,322

2. Summary of Significant Accounting Policies

Our accounting policies are set forth in Note 2 of the audited consolidated/combined financial statements in our Annual Report on Form 10-K for the year ended December 31, 2011, and are supplemented by the notes to these unaudited consolidated/combined condensed financial statements. There have been no significant changes to these policies other than noted below, and these unaudited consolidated/combined condensed financial statements should be read in conjunction with the audited consolidated/combined financial statements and notes in our Annual Report on Form 10-K for the year ended December 31, 2011.

Basis of Presentation

These interim financial statements are unaudited and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) regarding interim financial reporting. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America (GAAP) for complete consolidated/combined financial statements and should be read in conjunction with the audited consolidated/combined financial statements in our Annual Report on Form 10-K for the year ended December 31, 2011. While the year-end balance sheet data was derived from audited financial statements, this interim report does not include all disclosures required by GAAP for annual periods. These unaudited interim consolidated/combined financial statements reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for the periods presented.

Because Fund I owns 5,049,600 common units and all of our 6,720,000 subordinated units, representing an aggregate 52.4% limited partner interest in us, each acquisition of assets from Fund I is considered a transaction between entities under common control. As a result, we are required to revise our financial statements to include the activities of the Transferred Properties.

Accordingly, our historical financial statements previously filed with the SEC have been revised in this Quarterly Report on Form 10-Q to include the results attributable to the Transferred Properties as if the Partnership owned such assets for all periods presented in 2012. The consolidated financial statements for periods prior to our acquisition of the Transferred Properties have been prepared from our predecessor s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the assets during the periods reported. See our accounting policy below under Transactions Between Entities Under Common Control.

Net income attributable to the Transferred Properties for periods prior to the Partnership s acquisition of such assets was not available for distribution to our unitholders. Therefore, this income was not allocated to the limited partners for the purpose of calculating net income per common unit.

Revised Balance Sheet. Our historical balance sheet as of December 31, 2011 was impacted based on revisions from the Transferred Properties by an increase in total assets of $62.9 million which primarily represented increases to our property, plant and equipment. Total liabilities and partners capital was also increased by $62.9 million, comprised of increases of less than $0.1 million in current liabilities, $1.0 million in noncurrent liabilities and $61.9 million in partners capital.

Revised Statements of Operations. Our statements of operations for the three and six months ended June 30, 2012 were impacted based on revisions from the Transferred Properties by an increase in net income of $1.2 million and $2.3 million, respectively.

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Transactions Between Entities Under Common Control

Master limited partnerships (MLPs) enter into transactions whereby the MLP receives a transfer of certain assets from its sponsor or predecessor for consideration of either cash, units, assumption of debt, or any combination thereof. We account for the net assets received using the carryover book value of the predecessor as these are transactions between entities under common control. Our historical financial statements have been revised to include the results attributable to the assets contributed from Fund I as if we owned such assets for all periods presented by us. The following financial statement items were impacted:

Oil and Natural Gas Properties Received. The book value and related activity of oil and natural gas properties received from our predecessor is determined using the carrying value of the specific assets contributed.

Asset Retirement Obligations Received. The book value and related activity of asset retirement obligations received from our predecessor was determined by using the carrying value of the specific liabilities attributable to the assets contributed.

Oil, Natural Gas and NGL Revenues and Expenses. Oil, natural gas and NGL revenues and expenses related to the Transferred Properties are based on the actual results of the Transferred Properties. Historical lease operating statements by individual asset were used as the basis for revenues and direct operating expenses.

General and Administrative Expense. The general and administrative expense attributable to the Transferred Properties was determined by the ratio of production for the Transferred Properties to our total predecessor s production for the period presented.

Recent Accounting Pronouncements

In May 2011, the FASB issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. The Amendments explain how to measure fair value and change the wording used to describe many of the fair value requirements in GAAP, but do not require additional fair value measurements. The guidance became effective for interim and annual periods beginning on or after December 15, 2011. We adopted these amendments on January 1, 2012 and they did not have a material impact on our consolidated financial position, results of operations or cash flows.

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities. The amendments in this update require enhanced disclosures around financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

3. Acquisitions and Divestitures

Acquisitions Between Entities Under Common Control

On June 1, 2012, we completed the acquisition of the Transferred Properties from Fund I for a total purchase price of $65.1 million, after giving effect to purchase price adjustments from the effective date of the Transaction (March 1, 2012). The final post closing adjustments will be finalized in the third quarter of 2012. We financed the transaction with borrowings under our existing credit facility as discussed in Note 7. The net assets were recorded using carryover book value of Fund I as the acquisition was a transaction between entities under common control. Our historical financial statements were revised to include the results attributable to the Transferred Properties as if we owned the properties for all periods we have presented in our consolidated condensed financial statements. See Note 2 for further disclosures regarding this transaction.

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Third-Party Acquisitions

We acquire proved oil and natural gas properties that meet management s criteria with respect to reserve lives, development potential, production risk and other operational characteristics. We generally do not acquire assets other than oil and natural gas property interests. We assume the liability for asset retirement obligations (ARO) related to each acquisition and record the liability at fair value as of the date of closing.

Our acquisitions are accounted for under the acquisition method of accounting. Accordingly, we conduct assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while acquisition costs associated with the acquisitions are expensed as incurred.

The fair values of oil and natural gas properties and ARO are 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 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.

Our acquisitions typically qualify as business combinations, and as such, we estimate the fair value of these properties as of the acquisition dates. The fair value is 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 (exit price). Fair value measurements also utilize assumptions of market participants. In the estimation of fair value, we use a discounted cash flow model and make market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed under Note 4. After post-closing and title adjustments, the assets acquired and liabilities assumed approximate fair value for the acquisitions.

We did not acquire any significant properties from third-parties during the six months ended June 30, 2012 or 2011.

Divestitures

We did not divest any properties during the six months ended June 30, 2012 or 2011.

4. Fair Value Measurements

Our financial instruments, including cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. 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.

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As required by GAAP, 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 the predecessor s financial assets and liabilities that were accounted for at fair value on a recurring basis as of the date indicated (in thousands).

	Level 1	Level 2	Level 3	Total
June 30, 2012				
Assets:				
Commodity derivative instruments	$	$ 55,145	$	$ 55,145
Liabilities:				
Commodity derivative instruments		1,185		1,185
Interest rate derivative instruments		2,047		2,047

	Level 1	Level 2	Level 3	Total
December 31, 2011				
Assets:				
Commodity derivative instruments	$	$	$ 43,079	$ 43,079
Liabilities:				
Commodity derivative instruments			186	186

All fair values reflected in the table above and on the unaudited 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. We did not have any outstanding interest rate derivative instruments at December 31, 2011.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the three and six months ended June 30, 2012 and 2011 (in thousands):

	Partnership Three Months Ended June 30, 2012	Predecessor Three Months Ended June 30, 2011	Partnership Six Months Ended June 30, 2012	Predecessor Six Months Ended June 30, 2011
Balance at beginning of period	$	$ 4,398	$ 42,893	$ 23,504
Total gains or losses (realized or unrealized):				
Included in earnings		8,776		(3,203)
Settlements		7,384		257
Transfers in and out of Level 3 (1)			(42,893)	

Balance at end of period	$	$ 20,558	$	$ 20,558
Changes in unrealized gains (losses) relating to derivatives still held at end of period	$ 8,145	$ 16,160	$ 8,961	$ (2,946)

(1) As part of a review by management of our fair value financial statement disclosures in light of ASU 2011-04, management has determined, effective January 1, 2012, the fair values of our derivative instruments should be classified as Level 2. Management has determined the prices quoted by the independent pricing service are observable inputs that management is able to independently test and corroborate for reasonableness through market prices. Accordingly, on January 1, 2012, we

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transferred all derivative instruments which are measured on a recurring basis from Level 3 into Level 2.

5. Property and Equipment

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

		June 30, 2012		December 31, 2011
Oil and natural gas properties (successful efforts method)	$	742,424	$	723,505
Unproved properties		1,570		1,679
Other property and equipment		318		302
		744,312		725,486
Accumulated depletion, depreciation and impairment		(286,745)		(263,931)
Total property and equipment, net	$	457,567	$	461,555

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 six months ended June 30, 2012, we recorded non-cash impairment charges of approximately $3.1 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 for the three months ended June 30, 2012 or the three months and six months ended June 30, 2011.

The impairment of proved oil and natural gas properties was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in an internal reserve report. This report was based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 3 inputs. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the predecessor s 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 oil and 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 oil and natural gas prices. Significant assumptions in valuing the unproved reserves included the evaluation of the probable and possible reserves included in the internal reserve report, future expected oil and natural gas prices and basis differentials, and our anticipated drilling schedules.

This asset impairment had no impact on our cash flows, liquidity position, or debt covenants. If future oil or natural gas prices decline further during 2012, the estimated undiscounted future cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for our recently acquired properties and a non-cash impairment charge may be required to be recognized in future periods.

6. Asset Retirement Obligations

The following is a summary of our ARO as of and for the six months ended June 30, 2012 (in thousands):

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Beginning of period	$	24,154
Revisions to previous estimates		(131)
Liabilities incurred		166
Liabilities settled		(112)
Accretion expense		717
End of period		24,794
Less: Current portion of asset retirement obligations		(371)
Asset retirement obligations non-current	$	24,423

7. Long-Term Debt

In July 2011, subject to consummation of our IPO, we, as guarantor, and our wholly owned subsidiary, OLLC, as borrower, entered into a five-year, $500 million senior secured revolving credit facility, as amended, (the Credit Agreement) that matures in July 2016. The Credit Agreement is reserve-based and we are permitted to borrow under our credit facility an amount up to the borrowing base, which was $240 million as of June 30, 2012. Our borrowing base, which is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders at their sole discretion. Unanimous approval by the lenders is required for any increase to the borrowing base.

Borrowings under the Credit Agreement are secured by liens on at least 80% of the PV-10 value of our and our subsidiaries oil and natural gas properties and all of our equity interests in the OLLC and any future guarantor subsidiaries and all of our and our subsidiaries other assets including personal property. Borrowings under the Credit Agreement bear interest, at OLLC s option, at either (i) the greater of the prime rate as determined by the Administrative Agent, the federal funds effective rate plus 0.50%, and the 30-day adjusted LIBOR plus 1.0%, all of which is subject to a margin that varies from 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letter of credit exposure to the borrowing base then in effect), or (ii) the applicable reserve-adjusted LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

The Credit Agreement requires us to maintain a leverage ratio of Total Debt to EBITDAX (as each term is defined in the Credit Agreement) of not more than 4.0 to 1.0x, and a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0x.

Additionally, the Credit Agreement contains various covenants and restrictive provisions which limit our, OLLC s and any of our subsidiaries ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production; and prepay certain indebtedness. As of June 30, 2012, we were in compliance with all covenants contained in the Credit Agreement.

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

The obligations under the Term Loan Agreement are guaranteed on a joint and several basis by us. The obligations are secured by a second priority mortgage and security interest in all assets of OLLC and us that secure OLLC s and our existing indebtedness under the Credit Agreement.

Borrowings under the Term Loan Agreement mature on January 20, 2017, and, subject to the terms of the Intercreditor Agreement (as described below), OLLC has the ability at any time to prepay the Term Loan Agreement without premium or penalty. Borrowings under the Term Loan Agreement bear interest, at OLLC s option, at either

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- the greatest of (i) the prime rate as defined in the Term Loan Agreement, (ii) the federal funds effective rate plus 0.50% and (iii) the 30-day adjusted LIBOR plus 1.0%, all of which is subject to an applicable margin as follows:

- 4.50% through March 31, 2013;

- 6.00% from April 1, 2013 to December 31, 2013; and

- 7.50% from January 1, 2014 to January 20, 2017; or

- the applicable reserve-adjusted LIBOR plus an applicable margin as follows:

- 5.50% through March 31, 2013;

- 7.00% from April 1, 2013 to December 31, 2013; and

- 8.50% from January 1, 2014 to January 20, 2017.

Additionally, the Term Loan Agreement provides for an upfront fee of one percent of the aggregate maximum commitment amount, or $500,000.

The Term Loan Agreement contains various covenants and restrictive provisions which limit the ability of OLLC, us or any of our subsidiaries to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of its assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of production; prepay certain indebtedness; and amend the Credit Agreement or grant any liens to secure any indebtedness under the Credit Agreement.

The Term Loan Agreement also contains covenants that, among other things, require OLLC and us to maintain specified ratios including leverage ratio of Total Debt to EBITDAX of not more than 4.25 to 1.00x; a current ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0x; and an asset coverage ratio of Total Proved PV-10 to Total Debt of not less than 1.50 to 1.00x. As of June 30, 2012, we were in compliance with all covenants contained in the Term Loan Agreement.

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

As of June 30, 2012, we had approximately $222.8 million of outstanding debt and accrued interest was approximately $0.3 million. As of December 31, 2011, we had approximately $155.8 million of outstanding debt and accrued interest was approximately $0.5 million. Our outstanding debt increased primarily due to our recent acquisition of oil and natural gas properties from Fund I for approximately $65.1 million.

Interest expense for the three months and six months ended June 30, 2012 was approximately $1.3 million and $2.5 million, respectively. Interest expense for the three and six months ended June 30, 2011 was approximately $0.3 million and $0.6 million, respectively. Interest expense for the 2011 periods is related to LRR A s credit facility. As of June 30, 2012 and December 31, 2011, the weighted average interest rate on our Credit Agreement was 3.54% and 2.86%, respectively. Please refer to Note 8 below for a discussion of our interest rate derivative contracts.

8. Derivatives

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

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At June 30, 2012 and December 31, 2011, our open positions consisted of contracts such as (i) crude oil and natural gas financial collar contracts, (ii) crude oil, NGL and natural gas financial swaps, (iii) natural gas basis financial swaps, (iv) crude oil and natural gas puts and (v) interest rate swap agreements. Our derivative instruments are with the counterparties that are also lenders in our Credit Agreement.

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

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

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

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

At June 30, 2012, we had the following open commodity derivative contracts, which include the additional derivative contracts entered into as a result of our recent acquisition:

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	Index		2012		2013		2014		2015		2016
Natural gas positions											
Price swaps (MMBTUs)	NYMEX-HH		2,080,305		7,267,590		5,242,970		4,707,725		3,015,370
Weighted average price		$	5.67	$	5.15	$	5.71	$	5.92	$	4.29
Basis swaps (MMBTUs)	NYMEX		3,398,556		5,928,340		5,242,959		4,707,727		95,710
Weighted average price		$	(0.1114)	$	(0.1432)	$	(0.1559)	$	(0.1698)	$	(0.1087)
Collars (MMBTUs)	NYMEX-HH		1,410,560								
Floor-Ceiling price		$	4.75/7.31	$		$		$		$	
Puts (MMBTUs)	NYMEX-HH		232,285		178,710						
Strike price		$	2.00	$	3.00	$		$		$	
Oil Positions											
Price swaps (BBLs)	NYMEX-WTI		305,575		620,772		332,387		289,955		61,413
Weighted average price		$	98.70	$	95.19	$	99.56	$	97.60	$	89.90
Puts (BBLs)	NYMEX-WTI		5,250								
Strike price		$	70.00	$		$		$		$	
NGL Positions											
Price swaps (BBLs)	Mont Belvieu		93,528		144,323						
Weighted average price		$	51.34	$	50.49	$		$		$	

At December 31, 2011, we had the following open commodity derivative contracts:

	Index		2012		2013		2014		2015
Natural gas positions									
Price swaps (MMBTUs)	NYMEX-HH		3,684,189		5,757,645		5,107,055		4,596,205
Weighted average price		$	6.21	$	5.59	$	5.76	$	5.96
Collars (MMBTUs)	NYMEX-HH		2,902,801						
Floor-Ceiling price		$	4.75-7.31	$		$		$	
Oil Positions									
Price swaps (BBLs)	NYMEX-WTI		251,005		289,323		248,149		219,657
Weighted average price		$	102.20	$	101.30	$	100.01	$	98.90
NGL Positions									
Price swaps (BBLs)	Mont Belvieu		164,220						
Weighted average price		$	49.92	$		$		$	

At June 30, 2012, we had the following interest rate swap derivative contracts:

Effective	Maturity		Notional Amount (in thousands)	Average %	Index
February 2012	February 2015	$	150,000	0.5175%	LIBOR

February 2015	February 2017	75,000	1.7250%	LIBOR
February 2015	February 2017	75,000	1.7275%	LIBOR
June 2012	June 2015	70,000	0.52375%	LIBOR
June 2015	June 2017	70,000	1.4275%	LIBOR

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We did not have any outstanding interest rate swap derivative contracts as of December 31, 2011.

Effect of Derivative Instruments Balance Sheet

The fair value of our commodity and interest rate derivative instruments as of June 30, 2012 is included in the table below (in thousands):

	As of June 30, 2012			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$	$ 463	$ 1,584
Sale of Natural Gas Production				
Price swaps	11,838	22,450	64	152
Basis swaps			248	468
Collars	2,553			
Puts	47			
Sale of Crude Oil Production				
Price swaps	6,304	8,843	253	
Puts	12			
Sale of NGLs				
Price swaps	2,334	764		
	$ 23,088	$ 32,057	$ 1,028	$ 2,204

The fair value of our commodity derivative instruments as of December 31, 2011 is included in the table below (in thousands):

	As of December 31, 2011			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Sale of Natural Gas Production				
Price swaps	$ 10,762	$ 22,190	$	$
Collars	4,464			
Sale of Crude Oil Production				
Price swaps	838	4,825		
Sale of NGLs				
Price swaps			186	
	$ 16,064	$ 27,015	$ 186	$

Effect of Derivative Instruments Statement of Operations

The unrealized and realized gain or loss amounts and classification related to derivative instruments for the three and six months ended June 30, 2012 and 2011 are as follows (in thousands):

	Partnership Three Months Ended June 30, 2012	Predecessor Three Months Ended June 30, 2011	Partnership Six Months Ended June 30, 2012	Predecessor Six Months Ended June 30, 2011
Realized gains (losses):				
Commodity derivatives (revenue)	$ 6,820	$ (7,239)	$ 12,068	$ 41
Interest rate derivatives (other income/expense)	(108)	(145)	(141)	(298)
Unrealized gains (losses):				
Commodity derivatives (revenue)	10,997	16,124	11,008	(3,109)
Interest rate derivatives (other income/expense)	(2,852)	36	(2,047)	163

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Credit Risk. All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative instruments involves the risk that the counterparties may be unable to meet the financial terms of the transactions. We monitor the creditworthiness of each of its 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 we believe 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 the Management of Fund I and its Affiliates

As of June 30, 2012, 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 Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. owned all of the Class C member interests in our general partner. In addition, Fund I owned an aggregate of approximately 32.1% of our outstanding common units and all of our subordinated units representing limited partner interests in us. In addition, 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.

Contracts with our General Partner and its Affiliates

We have entered into agreements with our general partner and its affiliates. Refer to Note 1 in the consolidated/combined financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2011 for a description of those agreements. For the three and six months ended June 30, 2012, we paid Lime Rock Management approximately $0.5 million and $0.7 million, respectively, either directly or indirectly, related to these agreements.

In connection with the management of our business, Lime Rock Resources Operating Company, Inc. (OpCo), an affiliate of our general partner, provides services for invoicing and processing of payments to our vendors. Periodically, OpCo 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, 2012 are included below (in thousands):

	OpCo	Lime Rock Resources	Total
Balance as of December 31, 2011	$	$ (536)	$ (536)
Expenditures	(19,020)	(10,698)	(29,718)
Cash paid for expenditures	15,094	3,388	18,482
Revenues and other	3,143	8,046	11,189
Balance as of June 30, 2012	$ (783)	$ 200	$ (583)

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, 2012, our general partner and its affiliates held 5,049,600 of our common units, all of our subordinated units and 22,400 general partner units. During the six months ended June 30, 2012, we paid cash distributions of $0.4750 per outstanding unit, or $1.90 on an annualized basis, to all unitholders as of the respective record dates, which totaled approximately $15.9 million.

We announced our second quarter 2012 distribution on July 20, 2012 as discussed in Note 13.

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Contributions to Fund I

The following table presents cash received and payments made to Fund I related to the Transferred Properties for the five months ended June 30, 2012 prior to the acquisition of the net assets on June 1, 2012 (in thousands):

Cash receipts	$	(7,755)
Expenses paid		2,414
Capital expenditures paid		472
Contributions to Fund I	$	(4,869)

Predecessor Related Parties

Each of LRR A, LRR B and LRR C has a management agreement with Lime Rock Management, an affiliated entity, to provide management services for the operation and supervision of their respective funds. The management fee is determined by a formula based on the partners invested capital or the equity capital commitment. During the three and six months ended June 30, 2011, the predecessor expensed $1.5 million and $3.0 million, respectively, in management fees to Lime Rock Management.

For certain oil and natural gas properties where the predecessor is the operator, the predecessor receives income related to joint interest operations. For the three and six months ended June 30, 2011, the predecessor received $0.3 million and $0.6 million, respectively, of income, which reduced the management fee paid by the predecessor to Lime Rock Management. All related party transactions are at amounts believed to be commensurate with an arm s-length transaction between parties and are stated at fair market value.

10. Unitholders Equity

Initial Public Offering

On November 16, 2011, we completed our IPO of 9,408,000 common units representing limited partner interests in the Partnership at a price to the public of $19.00 per common unit, or $17.8125 per common unit after payment of the underwriting discount. Total net proceeds from the sale of common units in our IPO were $167.2 million ($178.8 million less $11.2 million for the underwriting discount and a $0.4 million structuring fee). IPO costs were approximately $4.7 million. We reimbursed Fund I for all costs they paid related to our IPO ($3.2 million). Net proceeds of the offering, along with $155.8 million of borrowings under our new $500 million senior secured revolving credit agreement, were utilized to make cash distributions and payments to Fund I of approximately $289.9 million and repay $27.3 million of LRR A s debt that we assumed at closing.

On December 14, 2011, we closed the partial exercise of the underwriters option to purchase additional units, and as a result, issued an additional 1,200,000 common units to the public. We used the net proceeds from the sale of the additional common units of $21.3 million, after deducting underwriting discounts and a structuring fee, to pay additional cash consideration for the properties purchased from Fund I in connection with the IPO and to make additional distributions to Fund I. In connection with our IPO, Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness.

Units Outstanding

As of June 30, 2012, we had 15,708,474 common units, 6,720,000 subordinated units and 22,400 general partner units outstanding. In addition, as of June 30, 2012, Fund I owned 5,049,600 common units and all of our subordinated units, representing a 52.4% limited partner interest in us.

11. Net Income Per Limited Partner Unit

The following sets forth the calculation of net income per limited partner unit for the three and six months ended June 30, 2012 (in thousands, except per unit amounts):

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	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Net income	$ 13,363	$ 18,319
Net income attributable to predecessor operations	(1,158)	(2,265)
Net income available to unitholders	12,205	16,054
Less: General partner s approximate 0.1% interest in net income	(12)	(16)
Limited partners interest in net income	$ 12,193	$ 16,038
Weighted average limited partner units outstanding:		
Common units	15,708	15,705
Subordinated units	6,720	6,720
Total	22,428	22,425
Net income per limited partner unit (basic and diluted)	$ 0.54	$ 0.72

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

12. Equity-Based Compensation

On November 10, 2011, our general partner adopted a long-term incentive plan (2011 LTIP) for employees, consultants and directors of our general partner and its affiliates, including Lime Rock Management and Lime Rock Resources Operating Company, Inc., 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, 2012, there were 1,449,126 units available for issuance under the 2011 LTIP. The 2011 LTIP is currently administered by our general partner s board of directors.

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

A summary of the status of the non-vested units as of June 30, 2012, is presented below:

	Number of Non-vested Units	Weighted Average Grant-Date Fair Value
Non-vested restricted units at January 1, 2012	42,474	$ 18.88
Granted	8,400	20.89
Vested		

Forfeited			
Non-vested restricted units at June 30, 2012	50,874	$	19.21

As of June 30, 2012, there was approximately $0.8 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 2.4 years. There were no vested restricted units as of June 30, 2012.

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13. Subsequent Events

On July 20, 2012, we announced that the board of directors of our general partner declared a cash distribution for the second quarter of 2012 of $0.4750 per outstanding unit, or $1.90 on an annualized basis. The distribution will be paid on August 14, 2012 to all unitholders of record as of the close of business on July 31, 2012. The aggregate amount of the distribution will be approximately $10.7 million.

In July 2012, we entered into the following commodity derivative hedges:

	Index	2014	2015	2016
Gas Hedges				
Price swaps (MMBTUs)	NYMEX-HH	633,129	618,836	1,863,620
Weighted average price		$ 3.945	$ 4.132	$ 4.275
Oil Hedges				
Price swaps (BBLs)	NYMEX-WTI	128,539	108,298	291,391
Weighted average price		$ 87.85	$ 86.15	$ 85.10

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

Cautionary Note Regarding Forward-Looking Statements

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

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

All statements, other than statements of historical fact, are forward-looking statements. These forward-looking statements can be identified by their use of terms and phrases such as may, predict, pursue, expect, estimate, project, plan, believe, intend, achievable, anticipate, target, continue, potential, should, could and similar terms and phrases. Although we believe that *the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties, some of which are beyond our control. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the risk factors described in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2011 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 the minimum quarterly distribution on our common units;*
- *our ability to replace the oil and natural gas reserves we produce;*
- *our substantial future capital expenditures, which may reduce our cash available for distribution and could materially affect our ability to make distributions on our common units;*
- *a decline in, or substantial volatility of, oil, natural gas or NGL prices;*
- *the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production;*
- *the risk that our hedging strategy may be ineffective or may reduce our income;*
- *uncertainty inherent in estimating our reserves;*
- *the risks and uncertainties involved in developing and producing oil and natural gas;*
- *risks related to potential acquisitions, including our ability to make accretive acquisitions on economically acceptable terms or to integrate acquired properties;*
- *competition in the oil and natural gas industry;*
- *cash flows and liquidity;*
- *restrictions and financial covenants 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;*
- *general economic conditions; and*

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

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

Overview

LRR Energy, L.P. (we, us, our, or the Partnership) is a Delaware limited partnership formed in April 2011 by Lime Rock Management LP (Li Rock Management), an affiliate of Lime Rock Resources A, L.P. (LRR A), Lime Rock Resources B, L.P. (LRR B) and Lime Rock Resources C, L.P. (LRR C), to operate, acquire, exploit and develop producing oil and natural gas properties in North America with long-lived, predictable production profiles. LRR A, LRR B and LRR C were formed by Lime Rock Management in July 2005 for the purpose of acquiring mature, low-risk producing oil and natural gas properties with long-lived production profiles. As used herein, references to Fund I or predecessor refer collectively to LRR A, LRR B and LRR C. Fund I is managed by Lime Rock Management and pays a management fee to Lime Rock Management. In addition, Fund I also receives administrative services from, and pays an administrative services fee to, Lime Rock Resources Operating Company, Inc.

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

Contribution of Properties

In connection with the completion of our IPO on November 16, 2011, pursuant to a contribution, conveyance and assumption agreement, we acquired specified oil and natural gas properties and related net profits interests and operations and certain commodity derivative contracts (the Partnership Properties) owned by LRR A, LRR B, and LRR C.

Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness. For further discussion regarding our IPO, please see Note 1 to the consolidated/combined condensed financial statements included in this report.

On June 1, 2012, we completed an acquisition from Fund I of certain oil and natural gas properties (the Transferred Properties) located in the Permian Basin region of New Mexico and onshore Gulf Coast region of Texas for $65.1 million in cash consideration (the Transaction). The Transaction was effective as of March 1, 2012.

Results of Operations

Our discussion and analysis of the results of operations below discusses the Partnership s and predecessor s results of operations separately. Because the historical results of our predecessor include results for both the properties conveyed to us in connection with our IPO and properties retained by our predecessor, we do not consider the historical results of our predecessor to be indicative of our future results. Our discussion and analysis below includes a comparison of the three months ended June 30, 2012 to the three months ended March 31, 2012. We believe this comparison will enable the reader to assess material changes in our results of operations in calendar year 2012. We will first compare our results of operations between comparable interim periods beginning with our Quarterly Report on Form 10-Q for the quarter ending March 31, 2013.

Because Fund I and its affiliates own 100% of our general partner and because Fund I owns 5,049,600 common units and all of our 6,720,000 subordinated units, representing an aggregate 52.4% limited partner interest in us, each acquisition of assets from Fund I is considered a transfer of net assets between entities under common control. As a result, we are required to revise our financial statements to include the activities of such assets for all periods

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presented, similar to a pooling of interests, to include the financial position, results of operations and cash flows of the assets acquired and liabilities assumed. The table set forth below includes selected recast historical financial information as if the Transferred Properties were owned by us for all periods presented.

	Partnership			Predecessor	
	Three Months Ended March 31, 2012	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
Revenues (in thousands):					
Oil sales	$ 15,358	$ 15,555	$ 30,913	$ 18,258	$ 34,661
Natural gas sales	5,441	4,345	9,786	10,929	21,754
Natural gas liquids sales	3,057	2,713	5,770	4,422	7,758
Realized gain (loss) on commodity derivative instruments	5,248	6,820	12,068	(7,239)	41
Unrealized gain (loss) on commodity derivative instruments	11	10,997	11,008	16,124	(3,109)
Other income	3		3	41	80
Total revenues	29,118	40,430	69,548	42,535	61,185
Expenses (in thousands):					
Lease operating expense	6,296	6,912	13,208	5,392	11,935
Production and ad valorem taxes	1,661	1,700	3,361	1,712	3,020
Depletion and depreciation	9,300	10,559	19,859	7,756	20,871
Impairment of oil and natural gas properties	3,093		3,093		
Management fees				1,495	2,967
General and administrative expense	3,072	3,229	6,301	1,510	3,206
Interest expense	1,128	1,332	2,460	273	559
Realized loss on interest rate derivative instruments	33	108	141	145	298
Unrealized (gain) loss on interest rate derivative instruments	(805)	2,852	2,047	(36)	(163)
Production:					
Oil (MBbls)	157	181	338	185	371
Natural gas (MMcf)	2,051	2,021	4,072	2,576	5,202
NGLs (MBbls)	61	70	131	84	154
Total (MBoe)	560	588	1,148	698	1,392
Average net production (Boe/d)	6,154	6,462	6,308	7,670	7,691
Average sales price:					
Oil (per Bbl)					
Sales price	$ 97.82	$ 85.94	$ 91.46	$ 98.69	$ 93.43
Effect of realized commodity derivative instruments	(0.27)	6.17	3.18	(59.80)	(26.42)
Realized price	$ 97.55	$ 92.11	$ 94.64	$ 38.89	$ 67.01
Natural gas (per Mcf)					
Sales price	$ 2.65	$ 2.15	$ 2.40	$ 4.24	$ 4.18
Effect of realized commodity derivative instruments	2.58	2.58	2.58	1.48	1.89
Realized price	$ 5.23	$ 4.73	$ 4.98	$ 5.72	$ 6.07
NGLs (per Bbl)					
Sales price	$ 50.11	$ 38.76	$ 44.05	$ 52.64	$ 50.38
	0.10	6.87	3.72		

Effect of realized commodity derivative instruments										
Realized price	$	50.21	$	45.63	$	47.77	$	52.64	$	50.38

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	Partnership			Predecessor	
	Three Months Ended March 31, 2012	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
Average unit cost per Boe:					
Lease operating expenses	$ 11.25	$ 11.76	$ 11.51	$ 7.72	$ 8.57
Production and ad valorem taxes	2.97	2.89	2.93	2.45	2.17
Depletion and depreciation	16.61	17.96	17.30	11.11	14.99
Management fees				2.14	2.13
General and administrative expenses	5.49	5.49	5.49	2.16	2.30

Our Results for the Three Months Ended June 30, 2012 Compared to the Three Months Ended March 31, 2012

We recorded net income of $13.4 million for the three months ended June 30, 2012 compared to net income of $5.0 million during the three months ended March 31, 2012. The following discussion summarizes key components of the changes between periods.

Sales Revenues. Sales revenues declined slightly from $23.9 million for the three months ended March 31, 2012 to $22.6 million for the three months ended June 30, 2012. Sales revenues for the three months ended June 30, 2012 consisted of oil sales of $15.6 million, natural gas sales of $4.3 million and NGL sales of $2.7 million. Our production volumes for the three months ended June 30, 2012 included 251 MBbls of oil and NGLs and 2,021 MMcf of natural gas, or 2,758 Bbl/d of oil and NGLs and 22,209 Mcf/d of natural gas. On an equivalent basis, production for the period was 588 MBoe, or 6,462 Boe/d. Sales revenues for the three months ended March 31, 2012 consisted of oil sales of $15.4 million, natural gas sales of $5.4 million and NGL sales of $3.1 million. Our production volumes for the three months ended March 31, 2012 included 218 MBbls of oil and NGLs and 2,051 MMcf of natural gas, or 2,396 Bbl/d of oil and NGLs and 22,538 Mcf/d of natural gas. On an equivalent basis, production for the period was 560 MBoe, or 6,154 Boe/d.

Our average sales price per Bbl for oil and NGLs for the three months ended June 30, 2012, excluding the effect of commodity derivative contracts, was $85.94 and $38.76, respectively. Our average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, was $2.15. Our average sales price per Bbl for oil and NGLs for the three months ended March 31, 2012, excluding the effect of commodity derivative contracts, was $97.82 and $50.11, respectively. Our average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, was $2.65.

During the third week in February 2012 and through the second week in March 2012, approximately 1,515 Bbls/d and 1.7 MMcf/d of our Red Lake field production was entirely shut-in due to a compression system upgrade at the third party gas plant that processes natural gas for our Red Lake field. The upgrade was initially expected to last 7 days, but it experienced delays and took 21 days to complete. We are currently producing above pre-curtailment daily production volumes.

Relating to the Pecos Slope field curtailment previously disclosed in our periodic reports filed with the SEC, approximately 1.0 MMcf/d of production was curtailed during the second quarter of 2012 due to the gas containing a nitrogen percentage greater than our gas purchaser s specification. The curtailment is expected to remain at this level until a field-wide nitrogen rejection facility is installed in January 2013 by the third-party gas gathering company. The actual timing and amount of resumed production may differ from these estimates.

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 three months ended June 30, 2012 of approximately $17.8 million, which is comprised of a realized gain of approximately $6.8 million and an unrealized gain of approximately $11.0 million. For the three months ended March 31, 2012, we recorded a net gain from our commodity hedging program of approximately $5.3 million, which is comprised of a realized gain of approximately $5.2 million and an unrealized gain of less than $0.1 million. Volatility in commodity prices has had a significant impact on our realized and unrealized gains and losses on commodity derivative contracts.

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Lease Operating Expenses. Our lease operating expenses were approximately $6.9 million, or $11.76 per Boe, for the three months ended June 30, 2012 compared to approximately $6.3 million, or $11.25 per Boe, for the three months ended March 31, 2012. Lease operating expenses increased in the second quarter primarily due to increased workover costs of approximately $0.4 million and increased transportation costs of approximately $0.3 million.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $1.7 million, or $2.89 per Boe, for the three months ended June 30, 2012 compared to approximately $1.7 million, or $2.97 per Boe, for the three months ended March 31, 2012. Production taxes accounted for approximately $1.6 million and ad valorem taxes for $0.1 million of the total taxes recorded during the three months ended June 30, 2012. Production taxes accounted for approximately $1.5 million and ad valorem taxes for $0.2 million of the total taxes recorded during the three months ended March 31, 2012.

Depletion and Depreciation. Our depletion and depreciation expense was approximately $10.6 million, or $17.96 per Boe, for the three months ended June 30, 2012 compared to approximately $9.3 million, or $16.61 per Boe, for the three months ended March 31, 2012. The increase in depletion and depreciation expense and per Boe amount was primarily due to higher production volumes and property and equipment balances during the three months ended June 30, 2012.

Impairment of Oil and Natural Gas Properties. We recorded an impairment of approximately $3.1 million for the three months ended March 31, 2012 due to a decline in natural gas prices during the period. We did not record an impairment charge in the three months ended June 30, 2012. If future oil or natural gas prices decline further during 2012, the estimated undiscounted future cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for our recently acquired properties and a non-cash impairment charge may be required to be recognized in future periods. As of August 10, 2012, the NYMEX-WTI oil spot price was $92.87 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.84 per MMBtu.

General and Administration Expenses. Our general and administrative expenses were approximately $3.2 million, or $5.49 per Boe, for the three months ended June 30, 2012 compared to approximately $3.1 million, or $5.49 per Boe, for the three months ended March 31, 2012.

Interest Expenses. Our interest expense is comprised of interest on our credit facility and term loan, amortization of debt issuance costs and realized gains (losses) on our interest rate derivative instruments. Interest expense was approximately $1.4 million and $1.2 million for the three months ended June 30, 2012 and March 31, 2012, respectively. The increase in interest expense was primarily due to the increased debt levels during the second quarter of 2012. Unrealized losses on interest rate derivative contracts was approximately $2.9 million for the three months ended June 30, 2012 compared to an approximately $0.8 million gain for the three months ended March 31, 2012. The unrealized loss in the three months ended June 30, 2012 was due to a decline in interest rates over the period.

Our Results for the Six Months Ended June 30, 2012

We recorded net income of $18.3 million for the six months ended June 30, 2012.

Sales Revenues. Sales revenues of $46.5 million for the period consisted of oil sales of $30.9 million, natural gas sales of $9.8 million and NGL sales of $5.8 million. Our production volumes for the period included 469 MBbls of oil and NGLs and 4,072 MMcf of natural gas, or 2,577 Bbl/d of oil and NGLs and 22,374 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,148 MBoe, or 6,308 Boe/d.

Our average sales price per Bbl for oil and NGLs for the period, excluding the effect of commodity derivative contracts, was $91.46 and $44.05, respectively. Our average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, was $2.40.

During the third week in February 2012 and through the second week in March 2012, approximately 1,515 Bbls/d and 1.7 MMcf/d of our Red Lake field production was entirely shut-in due to a compression system upgrade at the third party gas plant that processes natural gas for our Red Lake field. The upgrade was initially expected to

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last 7 days, but it experienced delays and took 21 days to complete. We are currently producing above pre-curtailment daily production volumes.

Relating to the Pecos Slope field curtailment previously disclosed in our periodic reports filed with the SEC, approximately 1.0 MMcf/d of production was curtailed during the second quarter of 2012 due to the gas containing a nitrogen percentage greater than our gas purchaser s specification. The curtailment is expected to remain at this level until a field-wide nitrogen rejection facility is installed in January 2013 by the third-party gas gathering company. The actual timing and amount of resumed production may differ from these estimates.

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 period of approximately $23.1 million, which is comprised of a realized gain of approximately $12.1 million and an unrealized gain of approximately $11.0 million.

Lease Operating Expenses. Our lease operating expenses were approximately $13.2 million, or $11.51 per Boe, for the period.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $3.4 million, or $2.93 per Boe, for the period. Production taxes accounted for approximately $3.1 million and ad valorem taxes for $0.3 million of the total taxes recorded.

Depletion and Depreciation. Our depletion and depreciation expense was approximately $19.9 million, or $17.30 per Boe, for the period.

Impairment of Oil and Natural Gas Properties. We recorded an impairment of approximately $3.1 million for the six months ended June 30, 2012 due to a decline in natural gas prices during the first quarter of 2012. If future oil or natural gas prices decline further during 2012, the estimated undiscounted future cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for our recently acquired properties and a non-cash impairment charge may be required to be recognized in future periods. As of August 10, 2012, the NYMEX-WTI oil spot price was $92.87 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.84 per MMBtu.

General and Administration Expenses. Our general and administrative expenses were approximately $6.3 million, or $5.49 per Boe, for the six months ended June 30, 2012.

Interest Expense. Our interest expense is comprised of interest on our credit facility, amortization of debt issuance costs and realized gains (losses) on our interest rate derivative instruments. Interest expense was approximately $2.6 million for the six months ended June 30, 2012. Unrealized losses on interest rate derivative contracts were approximately $2.0 million for the six months ended June 30, 2012. The unrealized loss in the six months ended June 30, 2012 was due to a decline in interest rates over the period.

Our Predecessor s Results for the Three Months Ended June 30, 2011

Our predecessor recorded net income of approximately $23.8 million for the three months ended June 30, 2011. Net income was driven by revenues and expenses as described below.

Sales Revenues. Sales revenues of $33.6 million for the three months ended June 30, 2011 consisted of oil sales of $18.3 million, natural gas sales of $10.9 million and NGL sales of $4.4 million. Our predecessor s production volumes for the period included 269 MBbls of oil and NGLs and 2,576 MMcf of natural gas, or 2,956 Bbl/d of oil and NGLs and 28,308 Mcf/d of natural gas. On an equivalent basis, production for the period was 698 MBoe, or 7,670 Boe/d.

Our predecessor s average sales price per Bbl for oil and NGLs for the three months ended June 30, 2011, excluding the effect of commodity derivative contracts, was $98.69 and $52.64, respectively. Our predecessor s average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, was $4.24.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, our predecessor recorded a net gain from its commodity hedging program for the period of approximately $8.9 million, which is

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comprised of a realized loss of approximately $7.2 million offset by an unrealized gain of approximately $16.1 million.

Lease Operating Expenses. Our predecessor s lease operating expenses were approximately $5.4 million, or $7.72 per Boe, for the three months ended June 30, 2011.

Production and Ad Valorem Taxes. Our predecessor s production and ad valorem taxes were approximately $1.7 million, or $2.45 per Boe, for the three months ended June 30, 2011.

Depletion and Depreciation. Our predecessor s depletion and depreciation expense for the three months ended June 30, 2011 was approximately $7.8 million, or $11.11 per Boe.

Impairment of Oil and Natural Gas Properties. Our predecessor did not record any impairment charges during the three months ended June 30, 2011.

Management Fees. Our predecessor incurred a management fee paid to Lime Rock Management in addition to the direct general and administrative expenses it incurred. The management fee was determined by a formula based on our predecessor s limited partners invested capital or the entity capital commitment in Fund I. Our predecessor s management fees were approximately $1.5 million for the three months ended June 30, 2011.

General and Administration Expenses. Our predecessor s general and administrative expenses for the three months ended June 30, 2011 were approximately $1.5 million, or $2.16 per Boe.

Interest Expense. Our predecessor s interest expense is comprised of interest on its credit facility, amortization of debt issuance costs and realized gains (losses) on its interest rate derivative instruments. Interest expense was approximately $0.4 million for the three months ended June 30, 2011. The impact of unrealized gains and losses from interest rate derivative instruments was immaterial.

Our Predecessor s Results for the Six Months Ended June 30, 2011

Our predecessor recorded net income of approximately $17.6 million for the six months ended June 30, 2011. Net income was driven by revenues and expenses as described below.

Sales Revenues. Sales revenues of $64.2 million for the six months ended June 30, 2011 consisted of oil sales of $34.7 million, natural gas sales of $21.7 million and NGL sales of $7.8 million. Our predecessor s production volumes for the period included 525 MBbls of oil and NGLs and 5,202 MMcf of natural gas, or 2,901 Bbl/d of oil and NGLs and 28,740 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,392 MBoe, or 7,691 Boe/d.

Our predecessor s average sales price per Bbl for oil and NGLs for the six months ended June 30, 2011, excluding the effect of commodity derivative contracts, was $93.43 and $50.38, respectively. Our predecessor s average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, was $4.18.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, our predecessor recorded a net loss from its commodity hedging program for the period of approximately $3.1 million, which is comprised of an immaterial realized gain offset by an unrealized loss of approximately $3.1 million.

Lease Operating Expenses. Our predecessor s lease operating expenses were approximately $11.9 million, or $8.57 per Boe, for the six months ended June 30, 2011. Our predecessor s lease operating expenses were impacted by additional expenses at one of our predecessor s fields in New Mexico related to increased saltwater disposal costs.

Production and Ad Valorem Taxes. Our predecessor s production and ad valorem taxes were approximately $3.0 million, or $2.17 per Boe, for the six months ended June 30, 2011. Production and ad valorem taxes were low primarily due to changes in the estimates of the appraisals on which property taxes were calculated and a severance tax refund of approximately $0.8 million.

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Depletion and Depreciation. Our predecessor s depletion and depreciation expense for the six months ended June 30, 2011 was approximately $20.9 million, or $14.99 per Boe.

Impairment of Oil and Natural Gas Properties. Our predecessor did not record any impairment charges during the six months ended June 30, 2011.

Management Fees. Our predecessor incurred a management fee paid to Lime Rock Management in addition to the direct general and administrative expenses it incurred. The management fee was determined by a formula based on our predecessor s limited partners invested capital or the entity capital commitment in Fund I. Our predecessor s management fees were approximately $3.0 million for the six months ended June 30, 2011.

General and Administration Expenses. Our predecessor s general and administrative expenses for the six months ended June 30, 2011 were approximately $3.2 million, or $2.30 per Boe, including approximately $2.0 million in transaction costs associated with the IPO during 2011.

Interest Expense. Our predecessor s interest expense is comprised of interest on its credit facility, amortization of debt issuance costs and realized gains (losses) on its interest rate derivative instruments. Interest expense was approximately $0.9 million for the six months ended June 30, 2011. The impact of unrealized gains and losses from interest rate derivative instruments was immaterial.

Non-GAAP Financial Measures

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

- *Plus*:

- Income tax expense (benefit);
- Interest expense-net, including realized and unrealized losses on interest rate derivative contracts;
- Depletion and depreciation;
- Accretion of asset retirement obligations;
- Amortization of equity awards;

- Gain (loss) on settlement of asset retirement obligations;
- Unrealized losses on commodity derivative contracts;
- Impairment of oil and natural gas properties; and
- Other non-recurring items that we deem appropriate.

- *Less*:

- Interest income;
- Unrealized gains on commodity derivative contracts; and
- Other non-recurring items that we deem appropriate.

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

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

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

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Adjusted EBITDA and Distributable Cash Flow should not be considered an alternative to net income, operating income, or any other measure of financial performance presented in accordance with GAAP. Our Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA and Distributable Cash Flow in the same manner.

Our Adjusted EBITDA for the three months ended June 30, 2012 and March 31, 2012 was approximately $17.7 million and $18.1 million, respectively. Our Adjusted EBITDA for the six months ended June 30, 2012 was approximately $35.8 million. Our predecessor s Adjusted EBITDA for the three months ended June 30, 2011 was approximately $16.3 million. Our predecessor s Adjusted EBITDA for the six months ended June 30, 2011 was approximately $43.2 million.

Our Distributable Cash Flow for the three months ended June 30, 2012 and March 31, 2012 was approximately $11.3 million and $11.4 million, respectively. Our Distributable Cash Flow for the six months ended June 30, 2012 was approximately $22.7 million.

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

Reconciliation of Adjusted EBITDA to Net Income

	Partnership			Predecessor	
(in thousands)	**Three Months Ended March 31, 2012**	**Three Months Ended June 30, 2012**	**Six Months Ended June 30, 2012**	**Three Months Ended June 30, 2011**	**Six Months Ended June 30, 2011**
Net income (loss)	$ 4,956	$ 13,363	$ 18,319	$ 23,813	$ 17,603
Income tax expense	126	24	150	103	146
Interest expense-net, including realized and unrealized losses on interest rate derivative instruments	356	4,292	4,648	382	694
Depletion and depreciation	9,300	10,559	19,859	7,756	20,871
Accretion of asset retirement obligations	356	361	717	372	744
Amortization of equity awards	69	81	150		
Gain on settlement of asset retirement obligations	(98)	(10)	(108)		
Unrealized losses on commodity derivative instruments					3,109
Impairment of oil and natural gas properties	3,093		3,093		
Interest income					(1)
Unrealized gain on commodity derivative instruments	(11)	(10,997)	(11,008)	(16,124)	
Adjusted EBITDA	$ 18,147	$ 17,673	$ 35,820	$ 16,302	$ 43,166

Distributable Cash Flow

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

(in thousands)	Three Months Ended March 31, 2012	Partnership Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Adjusted EBITDA	$ 18,147	$ 17,673	$ 35,820
Income tax expense	(126)	(24)	(150)
Cash interest expense	(1,410)	(1,080)	(2,490)
Estimated maintenance capital (1)	(5,250)	(5,250)	(10,500)
Distributable Cash Flow	$ 11,361	$ 11,319	$ 22,680

(1) Amount represents pro-rated capital for the period outstanding.

Liquidity and Capital Resources

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

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

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

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

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

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

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

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As of June 30, 2012, we had borrowing capacity of $67.2 million under our $500 million revolving credit facility ($240 million borrowing base less $172.8 million of outstanding borrowings) and $4.7 million of cash on hand. As of June 30, 2012, we had no available borrowing capacity under our $50 million term loan. Based upon current oil and natural gas price expectations and our commodity derivatives positions for the period ending June 30, 2012, which cover 93% of our estimated production from total proved developed producing reserves for the remainder of 2012, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient working capital to meet our total planned 2012 capital expenditures of approximately $31.0 million, of which approximately $21.0 million is maintenance capital, and planned 2012 annualized cash distributions of approximately $42.7 million. During the six months ended June 30, 2012, our cash capital expenditures totaled approximately $13.6 million. Our board of directors determines our distribution each quarter and there is no guarantee that the board will maintain or increase our current quarterly distribution of $0.4750 per unit.

Long-Term Debt

Revolving Credit Facility. In connection with our IPO, we, as guarantor, and our wholly owned subsidiary, LRE Operating, LLC (OLLC), as borrower, entered into a senior secured revolving credit facility (as amended, the Credit Agreement.) The Credit Agreement is a five-year, $500 million revolving credit facility with a current borrowing base of $240 million.

Our Credit Agreement is reserve-based, and we are permitted to borrow under our Credit Agreement in an amount up to the borrowing base, which is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. Our borrowing base is subject to redetermination on a semi-annual basis based on an engineering report with respect to our estimated oil, NGL and natural gas reserves, which will take into account the prevailing oil, NGL and natural gas prices at such time, as adjusted for the impact of our commodity derivative contracts. The borrowing base under the Credit Agreement, which was initially set at $250 million, was redetermined and decreased to $240 million during the quarter ended June 30, 2012 by our lending group based on their lower commodity price assumptions. We do not currently expect this reduction in our borrowing base to impact our operations, capital program, or ability to make quarterly cash distributions to our unitholders at currently anticipated levels. Unanimous approval by the lenders is required for any increase to the borrowing base. In the future, we may be unable to access sufficient capital under our Credit Agreement as a result of (i) a subsequent borrowing base redetermination or (ii) an unwillingness or inability on the part of our lenders to meet their funding obligations.

A future decline in commodity prices could result in a redetermination that lowers our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base, or we could be required to pledge other oil and natural gas properties as additional collateral. We do not anticipate having any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our Credit Agreement. Additionally, we will not be able to pay distributions to our unitholders in any such quarter in the event there exists a borrowing base deficiency or an event of default either before or after giving effect to such distribution or we are not in pro forma compliance with the Credit Agreement after giving effect to such distribution.

Borrowings under the Credit Agreement are secured by liens on substantially all of our properties, but in any event, not less than 80% of the PV-10 value of our oil and natural gas properties, and all of our equity interests in OLLC and any future guarantor subsidiaries and all of our other assets including personal property. Additionally, borrowings under the Credit Agreement bear interest, at our option, at either (i) the greater of the prime rate as determined by the Administrative Agent, the federal funds effective rate plus 0.50%, and the 30-day adjusted LIBOR plus 1.0%, all of which is subject to a margin that varies from 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

Our Credit Agreement requires maintenance of a ratio of Total Debt (as such term is defined in the Credit Agreement) to EBITDAX, which we refer to as the leverage ratio, of not more than 4.0 to 1.0x, and a ratio of

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consolidated current assets to consolidated current liabilities, which we refer to as the current ratio, of not less than 1.0 to 1.0x. Our Credit Agreement defines EBITDAX as consolidated net income plus the sum of interest, income taxes, depreciation, depletion, amortization, accretion, impairment charges, exploration expenses and other noncash charges, plus reasonable one-time fees, charges and expenses related to our IPO, our acquisition of the Partnership Properties and the closing of the Credit Agreement or other start up activities, minus all noncash income.

Additionally, the Credit Agreement contains various covenants and restrictive provisions which limit our ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production; and prepay certain indebtedness.

Events of default under the Credit Agreement include, but are not limited to, failure to make payments when due; any material inaccuracy in the representations and warranties of OLLC; the breach of any covenants continuing beyond the cure period; a matured payment default under, or other event permitting acceleration of, any other material debt; a change in management or change of control; a bankruptcy or other insolvency event; and certain material adverse effects on our business.

If we fail to perform our obligations under these and other covenants, 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, 2012, we were in compliance with all covenants contained in the Credit Agreement.

At June 30, 2012, we had approximately $172.8 million of outstanding borrowings under our Credit Agreement and available borrowing capacity of approximately $67.2 million. During the second quarter of 2012, we decided to accelerate our discretionary drilling program at our Red Lake field. As a result, we increased our capital expenditures and invested $7.8 million during the second quarter and accrued $6.7 million of expenditures as of June 30th, 2012. Due to these expenditures and the normal timing of our monthly receipts of cash, we borrowed $10.2 million under our Credit Agreement in August 2012. As of August 10, 2012, our undrawn availability under our Credit Agreement was $57.0 million.

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

The obligations under the Term Loan Agreement are guaranteed on a joint and several basis by us. The obligations are secured by a second priority mortgage and security interest in all assets of OLLC and us that secure OLLC s and our existing indebtedness under the Credit Agreement.

Borrowings under the Term Loan Agreement mature on January 20, 2017, and, subject to the terms of the Intercreditor Agreement (as described in the Term Loan Agreement), OLLC has the ability at any time to prepay the Term Loan Agreement without premium or penalty. Borrowings under the Term Loan Agreement bear interest, at OLLC s option, at either

- the greatest of (i) the prime rate as defined in the Term Loan Agreement, (ii) the federal funds effective rate plus 0.50% and (iii) the 30-day adjusted LIBOR plus 1.0%, all of which is subject to an applicable margin as follows:

- 4.50% through March 31, 2013;

- 6.00% from April 1, 2013 to December 31, 2013; and

- 7.50% from January 1, 2014 to January 20, 2017; or

- the applicable reserve-adjusted LIBOR plus an applicable margin as follows:

- 5.50% through March 31, 2013;

- 7.00% from April 1, 2013 to December 31, 2013; and

- 8.50% from January 1, 2014 to January 20, 2017.

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Additionally, the Term Loan Agreement provides for an upfront fee of one percent of the aggregate maximum commitment amount, or $500,000.

The Term Loan Agreement contains various covenants and restrictive provisions which limit the ability of OLLC, us or any of our subsidiaries to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of its assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of production; prepay certain indebtedness; and amend the Credit Agreement or grant any liens to secure any indebtedness under the Credit Agreement.

The Term Loan Agreement also contains covenants that, among other things, require OLLC and us to maintain specified ratios including leverage ratio of Total Debt to EBITDAX of not more than 4.25 to 1.00x; a current ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0x; and an asset coverage ratio of Total Proved PV-10 to Total Debt of not less than 1.50 to 1.00x. As of June 30, 2012, we were in compliance with all covenants contained in the Term Loan Agreement.

The obligations under the Term Loan Agreement and the Credit Agreement are governed by an Intercreditor Agreement with OLLC as borrower and us 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.

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, puts and collars in place as of June 30, 2012. The weighted average price is based on the swap price for oil, NGL and natural gas swaps and the floor price of oil and natural gas collars. We use swaps and collars as a mechanism for managing commodity price risks whereby we pay the counterparty floating prices and receive fixed prices from the counterparty. By entering into the hedge agreements, we mitigate the effect on our cash flows of changes in the prices we receive for our oil and natural gas production. These transactions are settled based upon the NYMEX-WTI price of oil and the NYMEX-Henry Hub price of natural gas on the average of the three final trading days of the month, with settlement occurring on the fifth day of the production month.

	Oil (NYMEX-WTI) Weighted Average		NGL (NYMEX-WTI) Weighted Average		Natural Gas (NYMEX-Henry Hub) Weighted Average	
Term	**$/Bbl**	**Bbls/d**	**$/Bbl**	**Bbls/d**	**$/Mmbtu**	**Mmbtu/d**
2012	$ 98.22	1,698	$ 51.34	511	$ 5.09	20,345
2013	$ 95.19	1,700	$ 50.49	395	$ 5.10	20,401
2014	$ 99.56	911	$		$ 5.71	14,364
2015	$ 97.60	794	$		$ 5.92	12,898
2016	$ 89.90	168	$		$ 4.29	8,261

The following table summarizes, for the periods presented, our natural gas basis swaps in place as of June 30, 2012. 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.

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	Centerpoint East			Houston Ship Channel			WAHA			TEXOK	
Term	$/Mmbtu		Mmbtu/d	$/Mmbtu		Mmbtu/d	$/Mmbtu		Mmbtu/d	$/Mmbtu		Mmbtu/d
2012	$	(0.1600)	7,593	$	(0.0639)	4,693	$	(0.0898)	5,190	$	(0.0800)	1,096
2013	$	(0.1950)	6,756	$	(0.0891)	3,729	$	(0.1200)	4,804	$	(0.1050)	953
2014	$	(0.2150)	6,086	$	(0.0850)	3,119	$	(0.1299)	4,306	$	(0.1250)	854
2015	$	(0.2300)	5,525	$	(0.0992)	2,686	$	(0.1398)	3,911	$	(0.1375)	776
2016	$			$	(0.0950)	178	$	(0.1375)	84	$		

Cash Flow Statements

		Partnership Six Months Ended June 30, 2012		Predecessor Six Months Ended June 30, 2011
Net cash provided by (used in):				
Operating activities	$	36,167	$	37,994
Investing activities		(13,632)		(23,585)
Financing activities		(19,392)		(20,831)

Operating Activities.

Partnership. Net cash provided by operating activities was approximately $36.2 million for the six months ended June 30, 2012. 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 and levels of production volumes.

Our working capital totaled $24.2 million and $23.1 million at June 30, 2012 and December 31, 2011, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $4.7 million and $1.5 million at June 30, 2012 and December 31, 2011, respectively.

Predecessor. Net cash provided by operating activities was approximately $38.0 million for the six months ended June 30, 2011.

Investing Activities.

Partnership. Net cash used in investing activities was approximately $13.6 million for the six months ended June 30, 2012, which primarily represented additions to our property and equipment balances during the period.

We expect to spend approximately $31.0 million in total capital expenditures in 2012, of which approximately $21.0 million represents maintenance capital expenditures, on the development of our oil and natural gas properties in 2012.

Predecessor. Net cash used in investing activities by our predecessor was approximately $23.6 million for the six months ended June 30, 2011. The cash used in investing activities was primarily related to the development of oil and natural gas properties of approximately $26.2 million and the acquisition of oil and natural gas properties of approximately $0.4 million, offset by dispositions of oil and natural gas properties of approximately $3.0 million.

Financing Activities.

Partnership. Net cash used in financing activities was approximately $19.4 million for the six months ended June 30, 2012, which included distributions paid to our unitholders of $15.9 million, contributions from our predecessor of $70.0 million and deferred financing costs of $0.5 million, offset by net borrowings of $67.0 million.

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Predecessor. Net cash used in financing activities by our predecessor was approximately $20.8 million for the six months ended June 30, 2011. The cash used in financing activities was primarily related to distributions of approximately $24.4 million, offset by capital contributions of approximately $3.6 million.

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.4750 per unit per quarter ($1.90 per unit on an annualized basis). Based on the number of common units, subordinated units and general partner units outstanding as of July 31, 2012, quarterly distributions to all of our unitholders at the minimum quarterly distribution rate for 2012 would total approximately $10.7 million.

We intend to pursue acquisitions of long-lived, low-risk producing oil and natural gas properties with reserve exploitation potential. We would expect to finance any significant acquisition of oil and natural gas properties in 2012 though external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities.

Off Balance Sheet Arrangements

As of June 30, 2012, we had no off-balance sheet arrangements.

Critical Accounting Policies and Estimates

There have been no material changes to our predecessor s critical accounting policies from those described in our Annual Report on Form 10-K for the year ended December 31, 2011 and those described in Note 1 of this Quarterly Report on Form 10-Q for the quarter ended June 30, 2012.

Recently Issued Accounting Pronouncements

In May 2011, the FASB issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. The Amendments explain how to measure fair value and change the wording used to describe many of the fair value requirements in GAAP, but do not require additional fair value measurements. The guidance became effective for interim and annual periods beginning on or after December 15, 2011. We adopted these amendments on January 1, 2012 and they did not have a material impact on our consolidated financial position, results of operations or cash flows.

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities. The amendments in this update require enhanced disclosures around financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

Supplemental Disclosures Regarding LRR Energy, L.P.

As noted above, the results discussed above included combined results for both the properties conveyed to us in connection with our IPO and properties retained by our predecessor. The following table provides selected results for the properties conveyed to us in connection with our IPO and for those properties acquired from our predecessor in June 2012. The following information is for informational purposes only and should not be considered indicative of future results.

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	Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
Production:		
Oil (MBbls)	150	301
Natural gas (MMcf)	2,436	4,887
NGLs (MBbls)	71	134
Total (MBoe)	627	1,250
Average net production (Boe/d)	6,890	6,906
Revenues (in thousands):		
Oil	$ 14,551	$ 27,807
Natural gas	10,255	20,354
NGLs	3,860	6,834
Lease operating expenses (in thousands)	$ 4,263	$ 10,038
Production and ad valorem taxes (in thousands)	$ 1,452	$ 2,495

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 Annual Report on Form 10-K for the year ended December 31, 2011 under the caption Management s Discussion and Analysis or 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 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 management, with the participation of our principal executive officers and principal financial officer, has concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of June 30, 2012.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. Legal Proceedings.

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

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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, 2011, other than noted below.

The derivatives legislation adopted by the U.S. Congress and related rules adopted and proposed to be adopted by federal regulators could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in July 2010, or the Dodd-Frank Act, establishes a new regulatory framework for derivative transactions (generally referred to as swaps), including oil and gas hedging transactions and interest rate swaps. As required by the Dodd-Frank Act, the Commodity Futures and Trading Commission, or CFTC, federal regulators of banks and other financial institutions, or the prudential regulators, and the SEC have adopted certain rules, and are in the process of adopting other rules, implementing the new law. Until all of these rules are adopted, effective and implemented in practice, we cannot determine the exact impact the new regulatory framework will have on our business.

Swaps designated by, and swaps within classes of swaps designated by, the CFTC will be required to be submitted for clearing on a derivatives clearing organization and, if accepted for clearing, cleared on such organization. Transactions in swaps accepted for clearing must be executed on an exchange that is a designated contract market or on a swap execution facility if such swaps are made available for trading thereon. If we were required to clear some or all of our swaps, including commodities derivative transactions, we anticipate that we will be required to post cash collateral for such swaps, if any. Posting of cash collateral reduces our ability to use our cash for capital expenditures or other partnership purposes and, therefore, could reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows.

The Dodd-Frank Act provides an exception from the clearing requirement that commercial end-users may elect for swaps they enter into to hedge or mitigate commercial risks. Moreover, the clearing requirement will not apply to swaps existing at the time the clearing requirement first becomes applicable to swaps of the same class if certain reporting requirements are met as to those swaps. Although we believe that we will be able to take advantage of these exceptions as to most, if not all, of our swaps, if any of our swaps do not meet the exemptions, we would have to clear such swaps, which could adversely affect our ability to execute our hedging program efficiently. In addition, the CFTC and the prudential regulators have proposed rules that would impose margin requirements for non-cleared swaps that could require us to post cash or other collateral for non-cleared swaps in certain circumstances. Even if we are not required to post cash or other collateral for all or some of our swaps, the banks and other parties who are our contractual counterparties will be required to comply with the Dodd-Frank Act s new requirements, and the costs of their compliance could be passed on to customers, including us, thus potentially decreasing the benefits to us of hedging transactions and reducing our cash flows. Moreover, the Dodd-Frank Act may require one or more of our swap counterparties to separate their derivative operations into entities, which may not be as creditworthy as our current counterparties. These changes might not only increase costs, but could also reduce the availability of some types of swaps that protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts and potentially increase our exposure to less creditworthy counterparties.

As required by the Dodd-Frank Act, the CFTC has adopted rules setting limits on the positions that a party may hold for its own account in certain futures contracts and economically equivalent futures contracts, options contracts, swaps and swaptions in a number of physical commodities, including NYMEX contracts relating to light sweet (WTI) crude oil and Henry Hub natural gas. The position limits rules will allow us to exceed position limits otherwise applicable to us to the extent a contract or swap we hold constitutes a bona fide hedging transaction or position. If for any reason any of our contracts relating to such commodities fail to qualify for the exemption from the position limits, our ability to execute strategic hedges to reduce commodity price uncertainty, and, thus, to protect cash flows could be impaired.

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

There were no sales of unregistered equity securities during the quarter ended June 30, 2012.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

None.

Item 6. Exhibits.

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

10.1*	Purchase and Sale Agreement between Lime Rock Resources A, L.P., Lime Rock Resources B, L.P., Lime Rock Resources C, L.P. (collectively, Seller) and LRR Energy, L.P. and LRE Operating, LLC (collectively, Purchaser) dated as of May 2, 2012.
10.2	Second Lien Credit Agreement dated as of June 28, 2012, among LRE Operating, LLC, as borrower, LRR Energy, L.P., as parent guarantor, the lenders from time to time party thereto and Wells Fargo Energy Capital, Inc., as administrative agent (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on July 3, 2012).
10.3	Second Amendment dated as of June 8, 2012 to 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, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A., as syndication agent, and BNP Paribas, Citibank, N.A. and Royal Bank of Canada, as co-documentation agents (incorporated by reference to Exhibit 10.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on July 3, 2012).
10.4	Third Amendment dated as of June 27, 2012 to 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, Wells Fargo Bank, National Association, as administrative agent,

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	Bank of America, N.A., as syndication agent, and BNP Paribas, Citibank, N.A. and Royal Bank of Canada, as co-documentation agents (incorporated by reference to Exhibit 10.3 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on July 3, 2012).
10.5	Intercreditor Agreement dated as of June 28, 2012, by and among Wells Fargo Bank, N.A., as first lien agent and collateral agent, Wells Fargo Energy Capital, Inc., as second lien agent, LRE Operating, LLC, as borrower, and LRR Energy, L.P., as parent guarantor (incorporated by reference to Exhibit 10.4 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on July 3, 2012).
31.1*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.3*	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
32.1*	Certification by Co-Chief Executive Officers and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith

** Submitted electronically herewith

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

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SIGNATURES

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

	LRR Energy, L.P.	
	By:	**LRE GP, LLC,** its General Partner
Date: August 14, 2012	By:	/s/ Eric Mullins Eric Mullins Co-Chief Executive Officer
Date: August 14, 2012	By:	/s/ Jaime R. Casas Jaime R. Casas Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)

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EXHIBIT INDEX

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10.3	Second Amendment dated as of June 8, 2012 to 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, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A., as syndication agent, and BNP Paribas, Citibank, N.A. and Royal Bank of Canada, as co-documentation agents (incorporated by reference to Exhibit 10.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on July 3, 2012).
10.4	Third Amendment dated as of June 27, 2012 to 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, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A., as syndication agent, and BNP Paribas, Citibank, N.A. and Royal Bank of Canada, as co-documentation agents (incorporated by reference to Exhibit 10.3 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on July 3, 2012).
10.5	Intercreditor Agreement dated as of June 28, 2012, by and among Wells Fargo Bank, N.A., as first lien agent and collateral agent, Wells Fargo Energy Capital, Inc., as second lien agent, LRE Operating, LLC, as borrower, and LRR Energy, L.P., as parent guarantor (incorporated by reference to Exhibit 10.4 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on July 3, 2012).
31.1*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.

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

* Filed herewith

** Submitted electronically herewith

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