LRR Energy, L.P.
Form 10-Q
May 11, 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 March 31, 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 May 4, 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			
	March 31, 2012		December 31, 2011	
ASSETS				
Current assets:				
Cash and cash equivalents	$	6,803	$	1,513
Accounts receivable		8,947		12,924
Commodity derivative instruments		18,151		16,064
Amounts due from affiliates		665		
Prepaid expenses		912		578
Total current assets		35,478		31,079
Property and equipment (successful efforts method)		651,735		644,188
Accumulated depletion, depreciation and impairment		(255,647)		(245,581)
Total property and equipment, net		396,088		398,607
Commodity derivative instruments		25,957		27,015
Interest rate derivative instruments		1,106		
Deferred financing costs, net of accumulated amortization		1,291		1,365
TOTAL ASSETS	$	459,920	$	458,066
LIABILITIES AND UNITHOLDERS EQUITY				
Current liabilities:				
Trade accounts payable	$	1,005	$	2,707
Accrued liabilities		3,909		2,739
Accrued capital cost		4,011		1,421
Commodity derivative instruments		890		186
Amounts due to affiliates				536
Interest rate derivative instruments		302		
Asset retirement obligations		365		359
Total current liabilities		10,482		7,948
Long-term liabilities:				
Commodity derivative instruments		314		
Revolving credit facility		155,800		155,800
Asset retirement obligations		22,976		22,780
Deferred tax liabilities		140		35
Total long-term liabilities		179,230		178,615
Total liabilities		189,712		186,563
Unitholders Equity:				
		436		438

General partner (22,400 units issued and outstanding as of March 31, 2012 and December 31, 2011)				
Public common unitholders (10,608,000 units issued and outstanding as of March 31, 2012 and December 31, 2011)		188,961		189,537
Affiliated common unitholders (5,049,600 units issued and outstanding as of March 31, 2012 and December 31, 2011)		34,700		35,007
Subordinated unitholders (6,720,000 units issued and outstanding as of March 31, 2012 and December 31, 2011)		46,111		46,521
Total Unitholders Equity		270,208		271,503
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$	459,920	$	458,066

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 March 31, 2012 (consolidated)	Predecessor Three Months Ended March 31, 2011 (combined)
Revenues:		
Oil sales	$ 10,971	$ 16,403
Natural gas sales	5,223	10,825
Natural gas liquids sales	2,589	3,336
Realized gain on commodity derivative instruments	5,248	7,280
Unrealized gain (loss) on commodity derivative instruments	11	(19,233)
Other income	3	39
Total revenues	24,045	18,650
Operating Expenses:		
Lease operating expense	5,032	6,543
Production and ad valorem taxes	1,486	1,308
Depletion and depreciation	7,011	13,115
Impairment of oil and natural gas properties	3,093	
Accretion expense	343	372
Gain on settlement of asset retirement obligations	(98)	
Management fees		1,472
General and administrative expense	2,847	1,696
Total operating expenses	19,714	24,506
Operating income (loss)	4,331	(5,856)
Other income (expense), net		
Interest income		4
Interest expense	(1,128)	(289)
Realized loss on interest rate derivative instruments	(33)	(153)
Unrealized gain on interest rate derivative instruments	805	127
Other income (expense), net	(356)	(311)
Income (loss) before taxes	3,975	(6,167)
Income tax expense	(126)	(43)
Net income (loss)	$ 3,849	(6,210)
Computation of net income per limited partner unit:		
General partners interest in net income	$ 4	
Limited partners interest in net income	$ 3,845	
Net income per limited partner unit	$ 0.17	
Weighted average number of limited partner units outstanding	22,421	

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)

	General Partner	Limited Partners Public Common	Limited Partners Affiliated Common	Limited Partners Affiliated Subordinated	Total
Balance, December 31, 2011	$ 438	$ 189,537	$ 35,007	$ 46,521	$ 271,503
Amortization of equity awards		69			69
Distribution	(5)	(2,474)	(1,173)	(1,561)	(5,213)
Net income	3	1,829	866	1,151	3,849
Balance, March 31, 2012	$ 436	$ 188,961	$ 34,700	$ 46,111	$ 270,208

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

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LRR Energy, L.P.

Condensed Statements of Cash Flows

(Unaudited)

(in thousands)

	Partnership Three Months Ended March 31, 2012 (consolidated)	Predecessor Three Months Ended March 31, 2011 (combined)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 3,849	$ (6,210)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion and depreciation	7,011	13,115
Impairment of oil and natural gas properties	3,093	
Unrealized (gain) loss on derivative instruments, net	(816)	19,106
Accretion expense	343	372
Amortization of equity awards	69	
Amortization of deferred financing costs and other	74	23
Gain on settlement of asset retirement obligations	(98)	
Changes in operating assets and liabilities:		
Change in receivables	3,977	1,934
Change in prepaid expenses	(334)	(3,983)
Change in trade accounts payable and accrued liabilities	(427)	(1,717)
Change in amounts due from affiliates	(1,201)	(77)
Net cash provided by operating activities	15,540	22,563
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of oil and natural gas properties	(274)	(410)
Development of oil and natural gas properties	(4,747)	(13,691)
Expenditures for other property and equipment	(16)	(40)
Net cash used in investing activities	(5,037)	(14,141)
CASH FLOWS FROM FINANCING ACTIVITIES		
Deferred financing costs		(1)
Capital contributions		1,766
Distributions	(5,213)	(14,012)
Net cash used in financing activities	(5,213)	(12,247)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	5,290	(3,825)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	1,513	12,455
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 6,803	$ 8,630
Supplemental disclosure of non-cash items to reconcile investing and financing activities		
Property and equipment:		
Change in accrued capital costs	$ (2,590)	$ 3,634
Asset retirement obligations	(141)	

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. 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. Net proceeds of the offering, along with $155.8 million of borrowings under our new $500 million senior secured revolving credit agreement (Note 7) 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. The net proceeds ($21.3 million) from the exercise of the underwriters option to purchase additional common units were used 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.

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 the 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):

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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

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 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.

Recent accounting pronouncements

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.

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.

3. Acquisitions and Divestitures

We did not acquire or divest any significant properties during the three months ended March 31, 2012 and 2011. 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

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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.

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.

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).

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	Level 1	Level 2	Level 3	Total
March 31, 2012				
Assets:				
Commodity derivative instruments	$	$ 44,108	$	$ 44,108
Interest rate derivative instruments		1,106		1,106
Liabilities:				
Commodity derivative instruments		1,204		1,204
Interest rate derivative instruments		302		302

	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 months ended March 31, 2012 and 2011 (in thousands):

	Partnership Three Months Ended March 31, 2012	Predecessor Three Months Ended March 31, 2011
Balance at beginning of period	$ 42,893	$ 23,504
Total gains or losses (realized or unrealized):		
Included in earnings		(11,979)
Settlements		(7,127)
Transfers in and out of Level 3 (1)	(42,893)	
Balance at end of period	$	$ 4,398
Changes in unrealized gains (losses) relating to derivatives still held at end of period	$ 816	$ (19,106)

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

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5. Property and Equipment

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

	March 31, 2012	December 31, 2011
Oil and natural gas properties (successful efforts method)	$ 650,059	$ 642,519
Unproved properties	1,358	1,367
Other property and equipment	318	302
	651,735	644,188
Accumulated depletion, depreciation and impairment	(255,647)	(245,581)
Total property and equipment, net	$ 396,088	$ 398,607

For the three months ended March 31, 2012, due to a significant decline in future natural gas price curves across all future production periods, we performed an impairment analysis of our oil and natural gas properties and other non-current assets. The NYMEX-Henry Hub spot price for natural gas declined from $2.98 per MMBtu at December 31, 2011 to $1.98 per MMBtu at March 31, 2012. For the three months ended March 31, 2012, we recorded a total non-cash impairment charge of approximately $3.1 million to impair the value of our proved oil and natural gas properties in the Mid-Continent region. This non-cash charge is included in Impairment of oil and natural gas properties line item in the consolidated statements of operations. We did not record an impairment charge for the three months ended March 31, 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 has no impact on our cash flows, liquidity position, or debt covenants. If future oil or natural gas prices continue to decline 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 three months ended March 31, 2012 (in thousands):

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Beginning of period	$	23,139
Revisions to previous estimates		(133)
Liabilities incurred		81
Liabilities settled		(89)
Accretion expense		343
End of period		23,341
Less: Current portion of asset retirement obligations		(365)
Asset retirement obligations non-current	$	22,976

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 (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 is currently $250 million. 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. We were in compliance with our covenants as of March 31, 2012.

As of March 31, 2012 and December 31, 2011, we had approximately $155.8 million of outstanding debt and accrued interest was approximately $0.2 million and $0.5 million, respectively. Interest expense for the three months ended March 31, 2012 was approximately $1.1 million. Interest expense for the three months ended March 31, 2011 was approximately $0.3 million. Interest expense for the 2011 period related to LRR A s credit facility. As of March 31, 2012 and December 31, 2011, the weighted average interest rate on our Credit Agreement was 2.83% and 2.86%, respectively.

We expect that our borrowing base will be redetermined by our lending group during the month of May. While our lending group will consider our recently announced acquisition of oil and natural gas reserves for $67 million in redetermining our borrowing base, we expect that our borrowing base will be slightly reduced by our lending group based upon their lower natural gas price assumptions. However, we expect to have the borrowing capacity to fund our announced acquisition that is scheduled to close on or about June 1, 2012. Further, we do not expect any anticipated 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.

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8. Derivatives

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

At March 31, 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 and (iv) interest rate swap agreements. Our derivative instruments are with the counterparties that are also lenders in our credit facility.

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

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	Index		2012		2013		2014		2015
Natural gas positions									
Price swaps (MMBTUs)	NYMEX-HH		2,701,256		5,757,645		5,107,055		4,596,205
Weighted average price		$	6.07	$	5.59	$	5.76	$	5.96
Basis swaps (MMBTUs)	NYMEX		4,940,244		5,757,660		5,107,044		4,596,204
Weighted average price		$	(0.1130)	$	(0.1447)	$	(0.1575)	$	(0.1715)
Collars (MMBTUs)	NYMEX-HH		2,146,209						
Floor-Ceiling price		$	4.75-7.31	$		$		$	
Oil Positions									
Price swaps (BBLs)	NYMEX-WTI		274,230		289,323		248,149		219,657
Weighted average price		$	102.43	$	101.30	$	100.01	$	98.90
NGL Positions									
Price swaps (BBLs)	Mont Belvieu		125,599		123,750				
Weighted average price		$	52.11	$	51.31	$		$	

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 March 31, 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

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 March 31, 2012 is included in the table below (in thousands):

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	As of March 31, 2012			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$ 1,106	$ 302	$
Sale of Natural Gas Production				
Price swaps	13,160	25,176		
Basis swaps	7		31	167
Collars	4,833			
Sale of Crude Oil Production				
Price swaps		781	834	118
Sale of NGLs				
Price swaps	151		25	29
	$ 18,151	$ 27,063	$ 1,192	$ 314

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 months ended March 31, 2012 and 2011 are as follows (in thousands):

	Partnership Three Months Ended March 31, 2012	Predecessor Three Months Ended March 31, 2011
Realized gains (losses):		
Commodity derivatives (revenue)	$ 5,248	$ 7,280
Interest rate derivatives (other income/expense)	(33)	(153)
Unrealized gains (losses):		
Commodity derivatives (revenue)	11	(19,233)
Interest rate derivatives (other income/expense)	805	127

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 present minimal credit risks to us. Additionally, we consider ourselves to be of substantial credit

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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 March 31, 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 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 months ended March 31, 2012, we paid Lime Rock Management approximately $0.2 million, either directly or indirectly, related to these agreements.

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 March 31, 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. On February 14, 2012, we paid a pro-rated cash distribution of $0.2323 per outstanding unit. The pro-rated amount corresponded to our minimum quarterly cash distribution of $0.4750 per unit, or $1.90 on an annualized basis. The proration period began on November 17, 2011, the day after the closing date of LRR Energy s initial public offering, and ended December 31, 2011. The aggregate amount of the distribution was $5.2 million.

We announced our first quarter 2012 distribution on April 13, 2012 as discussed in Note 13.

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 months ended March 31, 2011, the predecessor expensed $1.5 million 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 months ended March 31, 2011, the predecessor received $0.3 million, 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

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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 March 31, 2012, we had 15,708,474 common units, 6,720,000 subordinated units and 22,400 general partner units outstanding. In addition, as of March 31, 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 months ended March 31, 2012 (in thousands, except per unit amounts):

Net income	$	3,849
Less: General partner s 0.1% interest in net income		(4)
Limited partners interest in net income	$	3,845
Weighted average limited partner units outstanding:		
Common units		15,701
Subordinated units		6,720
Total		22,421
Net income per limited partner unit (basic and diluted)	$	0.17

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 March 31, 2012. The aggregate number of common units and subordinated units outstanding was 15,708,474 and 6,720,000, respectively, as of March 31, 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 March 31, 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.

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A summary of the status of the non-vested units as of March 31, 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 units at March 31, 2012	50,874	$	19.21

As of March 31, 2012, there was approximately $0.9 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 2.7 years. There were no vested restricted units as of March 31, 2012.

13. Subsequent Events

On April 13, 2012, we announced that the board of directors of our general partner declared a cash distribution for the first quarter of 2012 of $0.4750 per outstanding unit, or $1.90 on an annualized basis. The distribution will be paid on May 14, 2012 to all unitholders of record as of the close of business on April 27, 2012. The aggregate amount of the distribution will be approximately $10.7 million.

On May 2, 2012, we announced that we signed a definitive agreement to acquire certain oil and natural gas properties in the Permian Basin region in New Mexico and onshore Gulf Coast region in Texas from Fund I, for a purchase price of $67.0 million. We expect to finance the transaction with borrowings under our revolving credit facility. Terms of the transaction were approved on May 2, 2012 by the board of directors of our general partner and on May 1, 2012 by the board s conflicts committee, which is comprised entirely of independent directors. The transaction is expected to close on or about June 1, 2012, subject to customary approvals and closing conditions.

In connection with the acquisition announced in May 2012, we entered into the following commodity hedges:

	Index		2012		2013		2014		2015		2016
Gas Hedges											
Price swaps (MMBtus)	NYMEX-HH		124,355		170,680		135,915		111,520		95,710
Weighted average price		$	2.61	$	3.46	$	3.87	$	4.08	$	4.27
Oil Hedges											
Price swaps (Bbls)	NYMEX-WTI		67,745		93,330		84,235		70,295		61,413
Weighted average price		$	106.00	$	103.75	$	98.23	$	93.55	$	89.90
NGL Hedges											
Price swaps (Bbls)	Mont Belvieu		14,876		20,573						

Weighted average price	$ 46.48	$ 45.56	$	$	$

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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, anti continue, potential, should, could and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking *statements are reasonable, they do involve certain assumptions, risks and uncertainties some of which are beyond our control. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the risk factors described in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 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 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 in our credit facility;*
- *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*
- *legislation and governmental regulations, including climate change legislation and federal or state regulation of hydraulic fracturing.*

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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.

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. The underwriters partially exercised their option to purchase additional units and on December 14, 2011, we issued an additional 1,200,000 units to the public. The net proceeds from the exercise of the underwriters option to purchase additional common units were used 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.

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.

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.

Our discussion and analysis of the results of operations below discusses the partnership and predecessor s results of operations separately. Beginning with our Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, we expect we will compare the current quarterly results with the most recent prior quarter until we are able to discuss changes between comparable interim periods. We expect we will 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.

Results of Operations

The table below summarizes certain of the results of operations attributable to us and our predecessor for the periods indicated. 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 these historical results of our predecessor to be indicative of our future results. Nevertheless, they are presented here for illustrative purposes only to provide a possible context for our current operations.

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	Partnership Three Months Ended March 31, 2012	Partnership November 16, to December 31, 2011	Predecessor Three Months Ended March 31, 2011
Revenues (in thousands):			
Oil sales	$ 10,971	$ 6,118	$ 16,403
Natural gas sales	5,223	3,482	10,825
Natural gas liquids sales	2,589	1,567	3,336
Realized gain (loss) on commodity derivative instruments	5,248	4,015	7,280
Unrealized gain (loss) on commodity derivative instruments	11	6,664	(19,233)
Other income	3		39
Total revenues	24,045	21,846	18,650
Expenses (in thousands):			
Lease operating expense	5,032	2,441	6,543
Production and ad valorem taxes	1,486	850	1,308
Depletion and depreciation	7,011	3,923	13,115
Impairment of oil and natural gas properties	3,093		
Management fees			1,472
General and administrative expense	2,847	1,662	1,696
Interest expense	1,128	604	289
Realized loss on interest rate derivative instruments	33		153
Production:			
Oil (MBbls)	112	65	186
Natural gas (MMcf)	1,964	1,038	2,626
NGLs (MBbls)	52	27	70
Total (MBoe)	491	265	694
Average net production (Boe/d)	5,396	5,761	7,707
Average sales price:			
Oil (per Bbl)			
Sales price	$ 97.96	$ 94.12	$ 88.19
Effect of realized commodity derivative instruments	(0.38)	11.03	6.77
Realized price	$ 97.58	$ 105.15	$ 94.96
Natural gas (per Mcf)			
Sales price	$ 2.66	$ 3.35	$ 4.12
Effect of realized commodity derivative instruments	2.69	3.20	2.29
Realized price	$ 5.35	$ 6.55	$ 6.41
NGLs (per Bbl)			
Sales price	$ 49.79	$ 58.04	$ 47.66
Effect of realized commodity derivative instruments	0.12	(0.93)	
Realized price	$ 49.91	$ 57.11	$ 47.66
Average unit cost per Boe:			
Lease operating expenses	$ 10.24	$ 9.21	$ 9.43
Production and ad valorem taxes	3.02	3.21	1.88
Depletion and depreciation	14.27	14.80	18.90
Management fees			2.12
General and administrative expenses	5.79	6.27	2.44

Our Results for the Three Months Ended March 31, 2012

We recorded net income of $3.8 million during the three months ended March 31, 2012. Our net income was primarily driven by total revenues of $24.0 million offset by lease operating expenses of $5.0 million, production and ad valorem taxes of $1.5 million, depletion and depreciation of $7.0 million, an impairment charge of $3.1 million and general and administrative expenses of $2.8 million.

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Sales Revenues. Sales revenues of $18.8 million for the period consisted of oil sales of $11.0 million, natural gas sales of $5.2 million and NGL sales of $2.6 million. Our production volumes for the period included 164 MBbls of oil and NGLs and 1,964 MMcf of natural gas, or 1,802 Bbl/d of oil and NGLs and 21,582 Mcf/d of natural gas. On an equivalent basis, production for the period was 491 MBoe, or 5,396 Boe/d.

Our average sales price per Bbl for oil and NGLs for the period, excluding the effect of commodity derivative contracts, was $97.96 and $49.79, respectively. Our average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, was $2.66.

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 approximately 1,900 Boe per day from the Red Lake field, which is approximately 105% of pre-curtailment daily production volumes.

Relating to the Pecos Slope field curtailment disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011, approximately 1.3 MMcf/d of production was curtailed in January and February 2012 due to the gas containing a nitrogen percentage greater than our gas purchaser s specification. Beginning in late February of 2012, the curtailment was reduced and is currently approximately 0.8 MMcf/d and is expected to remain at this level until the field-wide nitrogen rejection facility is installed in October 2012 by the 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 $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.

Lease Operating Expenses. Our lease operating expenses were approximately $5.0 million, or $10.24 per Boe, for the period. The per Boe amount is higher than the period from November 16 to December 31, 2011 due to lower production caused by the curtailment and shut-in discussed above.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $1.5 million, or $3.02 per Boe, for the period. The per Boe amount is consistent with the period from November 16 to December 31, 2011. Production taxes accounted for approximately $1.3 million and ad valorem taxes for $0.2 million of the total taxes recorded.

Depletion and Depreciation. Our depletion and depreciation expense was approximately $7.0 million, or $14.27 per Boe, for the period. The per Boe amount is consistent with the period from November 16 to December 31, 2011.

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. 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 May 7, 2012, the NYMEX-WTI oil spot price was $97.94 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.30 per MMBtu.

General and Administration Expenses. Our general and administrative expenses were approximately $2.8 million, or $5.79 per Boe, for the three months ended March 31, 2012. The per Boe amount is lower than the period from November 16 to December 31, 2011 due to additional payroll costs in the 2011 period related to allocated bonuses.

Interest Expenses. 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 $1.2 million for the three months ended March 31, 2012.

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Our Predecessor s Results for the Three Months Ended March 31, 2011

Our predecessor recorded a net loss of approximately $6.2 million for the three months ended March 31, 2011. Net loss was primarily driven by total revenues of $18.6 million offset by lease operating expenses of $6.5 million, production and ad valorem taxes of $1.3 million, depletion and depreciation of $13.1 million, management fees of $1.5 million and general and administrative expenses of $1.7 million.

Sales Revenues. Sales revenues of $30.5 million for the period consisted of oil sales of $16.4 million, natural gas sales of $10.8 million and NGL sales of $3.3 million. Our predecessor s production volumes for the period included 256 MBbls of oil and NGLs and 2,626 MMcf of natural gas, or 2,844 Bbl/d of oil and NGLs and 29,178 Mcf/d of natural gas. On an equivalent basis, production for the period was 694 MBoe, or 7,707 Boe/d.

Our predecessor s average sales price per Bbl for oil and NGLs for the period, excluding the effect of commodity derivative contracts, was $88.19 and $47.66, respectively. Our predecessor s average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, was $4.12.

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 $11.9 million, which is comprised of a realized gain of approximately $7.3 million and an unrealized loss of approximately $19.2 million.

Lease Operating Expenses. Our predecessor s lease operating expenses were approximately $6.5 million, or $9.43 per Boe, for the period. Our predecessor s lease operating expenses were impacted by approximately $1.2 million of 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 $1.3 million, or $1.88 per Boe, for the period. Production and ad valorem taxes were low primarily due to changes in the estimates of the appraisals on which property taxes were calculated.

Depletion and Depreciation. Our predecessor s depletion and depreciation expense for the period was approximately $13.1 million, or $18.90 per Boe.

Impairment of Oil and Natural Gas Properties. Our predecessor did not record any impairment charges during the period.

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 period.

General and Administration Expenses. Our predecessor s general and administrative expenses for the period were approximately $1.7 million, or $2.44 per Boe.

Interest Expenses. 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 period.

Non-GAAP Financial Measures

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

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- *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, net of realized losses on interest rate swaps; and estimated maintenance capital expenditures. Distribution Coverage Ratio is defined as the ratio of Distributable Cash Flow to the total quarterly distribution payable on all of our outstanding common, subordinated and general partner units.

Adjusted EBITDA, Distributable Cash Flow and Distribution Coverage Ratio 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;
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders; and
- our ability to incur and service debt and fund capital expenditures.

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

Our Adjusted EBITDA for the three months ended March 31, 2012 and the period from November 16 to December 31, 2011 was approximately $14.7 million and $10.3 million, respectively. Our predecessor s Adjusted EBITDA for the three months ended March 31, 2011 was approximately $26.9 million. Our Distributable Cash Flow for the three months ended March 31, 2012 and the period from November 16 to December 31, 2011 was approximately $8.7 million and $8.0 million, respectively. Our Distribution Coverage Ratio for the three months ended March 31, 2012 and the period from November 16 to December 31, 2011 was approximately 0.82 and 1.53, respectively.

The following table presents a reconciliation of Adjusted EBITDA to net income and net cash provided by operating activities, our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

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Reconciliation of Adjusted EBITDA to Net Income

(in thousands)	Partnership Three Months Ended March 31, 2012	Partnership November 16, to December 31, 2011	Predecessor Three Months Ended March 31, 2011
Net income (loss)	$ 3,849	$ 12,150	$ (6,210)
Income tax expense	126	48	43
Interest expense-net, including realized and unrealized losses on interest rate derivative instruments	356	604	315
Depletion and depreciation	7,011	3,923	13,115
Accretion of asset retirement obligations	343	168	372
Amortization of equity awards	69	31	
Gain on settlement of asset retirement obligations	(98)		
Unrealized losses on commodity derivative instruments			19,233
Impairment of oil and natural gas properties	3,093		
Interest income			(4)
Unrealized gain on commodity derivative instruments	(11)	(6,664)	
Adjusted EBITDA	$ 14,738	$ 10,260	$ 26,864

Reconciliation of Adjusted EBITDA to Net Cash Provided by Operating Activities

(in thousands)	Partnership Three Months Ended March 31, 2012	Partnership November 16, to December 31, 2011	Predecessor Three Months Ended March 31, 2011
Net cash provided by operating activities	$ 15,540	$ 2,173	$ 22,563
Change in working capital	(2,015)	7,485	3,843
Interest expense-net	1,087	554	415
Income tax expense	126	48	43
Adjusted EBITDA	$ 14,738	$ 10,260	$ 26,864

Distributable Cash Flow and Distribution Coverage Ratio

The following table presents a reconciliation of Distributable Cash Flow and Distribution Coverage Ratio to Adjusted EBITDA for each of the periods presented. Adjusted EBITDA is reconciled to net income and net cash provided by operating activities, our most directly comparable GAAP performance and liquidity measures, above.

(in thousands)	Partnership Three Months Ended March 31, 2012		November 16, to December 31, 2011	
Adjusted EBITDA	$	14,738	$	10,260
Income tax expense		(126)		(48)
Cash interest expense		(1,410)		
Estimated maintenance capital (1)		(4,500)		(2,250)
Distributable Cash Flow	$	8,702	$	7,962
Cash distribution	$	10,664	$	5,213
Distribution Coverage Ratio		0.82x		1.53x

(1) Estimated annual maintenance capital was $18 million for 2012 and 2011. Amount represents pro-rated capital for the period outstanding.

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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. 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 plan to reinvest a sufficient amount of our cash flow to fund our exploitation and development capital expenditures in order to maintain our production, and we plan 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 will need to make acquisitions to sustain our level of distributions to unitholders over time.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures, reduce distributions to unitholders, and/or fund a portion of our capital expenditures using borrowings under our credit facility, 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. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

As of March 31, 2012, we had borrowing capacity of $94.2 million under our $500 million revolving credit facility ($250 million borrowing base less $155.8 million of outstanding borrowings) and $6.8 million of cash on hand. Based upon current oil and natural gas price expectations and our commodity derivatives positions for the period ending March 31, 2012, which cover 84% of our estimated production from total proved developed

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producing reserves, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient working capital to meet our total planned 2012 capital expenditures of approximately $21.2 million, of which approximately $18.0 million is maintenance capital, and planned 2012 annualized cash distributions of approximately $42.7 million. During the three months ended March 31, 2012, our cash capital expenditures totaled approximately $5.0 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.

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. The credit facility is a five-year, $500 million revolving credit facility with a current borrowing base of $250 million.

Our credit facility is reserve-based, and we are permitted to borrow under our credit facility 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. 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 new credit facility 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 facility. 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 facility after giving effect to such distribution.

Borrowings under the credit facility 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 facility will 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 would be 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 facility requires maintenance of a ratio of Total Debt (as such term is defined in the credit facility) to EBITDAX, which we refer to as the leverage ratio, of not more than 4.0 to 1.0x, and a ratio of 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 facility 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 facility or other start up activities, minus all noncash income.

Additionally, the credit facility 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

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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 facility 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 facility, together with accrued interest, could be declared immediately due and payable. As of March 31, 2012, we are in compliance with our covenants.

At March 31, 2012, we had approximately $155.8 million of outstanding borrowings under our credit facility and available borrowing capacity of approximately $94.2 million.

We expect that our borrowing base will be redetermined by our lending group during the month of May. While our lending group will consider our recently announced acquisition of oil and natural gas reserves for $67 million in redetermining our borrowing base, we expect that our borrowing base will be slightly reduced by our lending group based upon their lower natural gas price assumptions. However, we expect to have the borrowing capacity to fund our announced acquisition that is scheduled to close on or about June 1, 2012. Further, we do not expect any anticipated 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.

Derivative Contracts

The following table summarizes, for the periods presented, the weighted average price and notional volumes of our oil, NGL and natural gas swaps and collars in place as of March 31, 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	$ 102.43	1,001	$ 52.11	458	$ 5.49	17,691
2013	$ 101.30	793	$ 51.31	339	$ 5.59	15,774
2014	$ 100.01	680	$		$ 5.76	13,992

2015	$	98.90	602	$	$	5.96	12,592

The following table summarizes, for the periods presented, our natural gas basis swaps in place as of March 31, 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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Term	Centerpoint East $/Mmbtu	Centerpoint East Mmbtu/d	Houston Ship Channel $/Mmbtu	Houston Ship Channel Mmbtu/d	WAHA $/Mmbtu	WAHA Mmbtu/d	TEXOK $/Mmbtu	TEXOK Mmbtu/d
2012	$ (0.160)	7,607	$ (0.065)	4,293	$ (0.090)	5,033	$ (0.080)	1,098
2013	$ (0.195)	6,756	$ (0.090)	3,399	$ (0.120)	4,667	$ (0.105)	953
2014	$ (0.215)	6,086	$ (0.085)	2,859	$ (0.130)	4,193	$ (0.125)	854
2015	$ (0.230)	5,525	$ (0.100)	2,476	$ (0.140)	3,815	$ (0.138)	776

	Partnership Three Months Ended March 31, 2012	Predecessor Three Months Ended March 31, 2011
Net cash provided by (used in):		
Operating activities	$ 15,540	$ 22,563
Investing activities	(5,037)	(14,141)
Financing activities	(5,213)	(12,247)

Operating Activities.

Partnership. Net cash provided by operating activities was approximately $15.5 million for the three months ended March 31, 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 $25.0 million and $23.1 million at March 31, 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 $6.8 million and $1.5 million at March 31, 2012 and December 31, 2011, respectively.

Predecessor. Net cash provided by operating activities was approximately $22.6 million for the three months ended March 31, 2011.

Investing Activities.

Partnership. Net cash used in investing activities was approximately $5.0 million for the three months ended March 31, 2012, which primarily represented additions to our property and equipment balances during the period.

We expect to spend approximately $21.2 million in total capital expenditures in 2012, of which approximately $18.0 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 $14.1 million for the three months ended March 31, 2011, primarily for the development of oil and natural gas properties during the period.

Financing Activities.

Partnership. Net cash used in financing activities was approximately $5.2 million for the three months ended March 31, 2012, which represents distributions paid to our unitholders during the period.

Predecessor. Net cash used in financing activities by our predecessor was approximately $12.2 million for the three months ended March 31, 2011. The cash used in financing activities was primarily related to distributions of $14.0 million offset by capital contributions of $1.8 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 April 27, 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 March 31, 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.

Recently Issued Accounting Pronouncements

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.

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.

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 only the properties conveyed to us in connection with our IPO. The following information is for informational purposes only and should not be considered indicative of future results.

	Three Months Ended March 31, 2011
Production:	
Oil (MBbls)	111
Natural gas (MMcf)	2,340
NGLs (MBbls)	52
Total (MBoe)	553
Average net production (Boe/d)	6,144

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		Three Months Ended March 31, 2011
Revenues (in thousands):		
Oil	$	9,708
Natural gas		9,649
NGLs		2,478
Lease operating expenses (in thousands)	$	5,438
Production and ad valorem taxes (in thousands)	$	602

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 March 31, 2012.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended March 31, 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 statues to which we or our general partner is subject.

Item 1A. Risk Factors.

There have been no material changes to the risk factors described in our Annual Report on Form 10-K for the year ended December 31, 2011.

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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 March 31, 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).

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.

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

* Incorporated by reference

** 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: May 11, 2012	By:	/s/ Eric Mullins Eric Mullins Co-Chief Executive Officer
Date: May 11, 2012		
	By:	/s/ Jaime R. Casas Jaime R. Casas Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)

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* Incorporated by reference

** 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.