NATURAL RESOURCE PARTNERS LP
Form 10-Q
August 07, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2012

OR

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

Commission file number: 001-31465

NATURAL RESOURCE PARTNERS L.P.

(Exact name of registrant as specified in its charter)

Delaware	**35-2164875**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

601 Jefferson Street, Suite 3600

Houston, Texas 77002

(Address of principal executive offices)

(Zip Code)

(713) 751-7507

(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 ¨

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 ¨

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 definition of accelerated filer , large accelerated filer , and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer	x	Accelerated Filer	¨
Non-accelerated Filer	¨ (Do not check if a smaller reporting company)	Smaller Reporting Company	¨

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

At August 7, 2012 there were 106,027,836 Common Units outstanding.

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Forward-Looking Statements

Statements included in this Form 10-Q are forward-looking statements. In addition, we and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

Such forward-looking statements include, among other things, statements regarding capital expenditures, acquisitions and dispositions, expected commencement dates of mining, projected quantities of future production by our lessees and projected demand for or supply of coal, aggregates and oil and gas that will affect sales levels, prices and royalties and other revenues realized by us.

These forward-looking statements are made based upon management s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

You should not put undue reliance on any forward-looking statements. Please read Item 1A. Risk Factors in our Form 10-K for the year ended December 31, 2011 for important factors that could cause our actual results of operations or our actual financial condition to differ.

Prior Year Financial Information

We restated certain income-related items with respect to 2011 to properly reflect them in the correct quarter. Please read Note 17. Supplemental Financial Information (unaudited) in our Form 10-K for the year ended December 31, 2011 for additional information related to the restatements of our prior year financial data.

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Part I. Financial Information

Item 1. Financial Statements

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands, except unit data)

	June 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 121,974	$ 214,922
Accounts receivable, net of allowance for doubtful accounts	33,029	30,923
Accounts receivable affiliates	12,897	10,138
Other	526	832
Total current assets	168,426	256,815
Land	24,515	24,534
Plant and equipment, net	42,967	46,185
Coal and other mineral rights, net	1,324,654	1,257,501
Intangible assets, net	72,972	75,164
Loan financing costs, net	4,569	4,846
Long-term contracts receivable affiliate	55,371	
Other assets, net	886	604
Total assets	$ 1,694,360	$ 1,665,649
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 2,905	$ 2,366
Accounts payable affiliates	398	375
Obligation related to acquisitions		500
Current portion of long-term debt	87,230	30,801
Accrued incentive plan expenses current portion	6,982	8,374
Property, franchise and other taxes payable	5,734	6,316
Accrued interest	10,603	10,761
Total current liabilities	113,852	59,493
Deferred revenue	118,373	113,303
Accrued incentive plan expenses	7,801	11,670
Long-term debt	829,731	836,268
Partners capital:		
Common units outstanding (106,027,836)	611,845	629,253
General partner s interest	10,162	10,517
Non-controlling interest	3,066	5,638
Accumulated other comprehensive loss	(470)	(493)
Total partners capital	624,603	644,915
Total liabilities and partners capital	$ 1,694,360	$ 1,665,649

The accompanying notes are an integral part of these financial statements.

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In thousands, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(Unaudited)		(Unaudited)	
		(Restated)		(Restated)
Revenues:				
Coal royalties	$ 62,878	$ 71,242	$ 122,794	$ 136,607
Aggregate royalties	1,702	1,831	3,418	3,025
Processing fees	3,138	3,173	5,264	6,262
Transportation fees	5,246	3,745	9,354	7,843
Oil and gas royalties	4,078	1,996	5,466	4,988
Property taxes	3,331	3,577	7,819	6,589
Minimums recognized as revenue	938	2,520	12,652	3,027
Override royalties	3,497	3,492	8,639	6,535
Other	5,856	4,956	7,130	6,508
Total revenues	90,664	96,532	182,536	181,384
Operating costs and expenses:				
Depreciation, depletion and amortization	15,172	17,435	27,581	31,757
General and administrative	7,029	6,439	15,979	16,635
Property, franchise and other taxes	3,771	3,306	8,787	7,003
Transportation costs	527	523	1,000	991
Coal royalty and override payments	673	159	873	467
Total operating costs and expenses	27,172	27,862	54,220	56,853
Income from operations	63,492	68,670	128,316	124,531
Other income (expense):				
Interest expense	(13,578)	(12,429)	(27,138)	(23,016)
Interest income	24	16	69	24
Income before non-controlling interest	49,938	56,257	101,247	101,539
Less non-controlling interest		51		51
Net income	$ 49,938	$ 56,206	$ 101,247	$ 101,488
Net income attributable to:				
General partner	$ 999	$ 1,124	$ 2,025	$ 2,030
Limited partners	$ 48,939	$ 55,082	$ 99,222	$ 99,458
Basic and diluted net income per limited partner unit	$ 0. 46	$ 0. 52	$ 0. 94	$ 0. 94
Weighted average number of units outstanding	106,028	106,028	106,028	106,028
Comprehensive income	$ 49,951	$ 56,218	$ 101,270	$ 101,513

The accompanying notes are an integral part of these financial statements.

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Six Months Ended June 30, 2012 (Unaudited)	Six Months Ended June 30, 2011 (Restated)
Cash flows from operating activities:		
Net income	$ 101,247	$ 101,488
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	27,581	31,757
Gains on sale of assets	(4,108)	
Gain on reserve swap		(2,990)
Non-cash interest charge, net	300	268
Non-controlling interest		51
Change in operating assets and liabilities:		
Accounts receivable	5,851	(3,785)
Other assets	24	532
Accounts payable and accrued liabilities	562	(485)
Accrued interest	(158)	1,868
Deferred revenue	6,551	12,519
Accrued incentive plan expenses	(5,261)	(1,130)
Property, franchise and other taxes payable	(582)	(1,413)
Net cash provided by operating activities	132,007	138,680
Cash flows from investing activities:		
Acquisition of land, coal and other mineral rights	(94,453)	(99,368)
Acquisition or construction of plant and equipment	(492)	(325)
Proceeds from sale of assets	285	1,100
Return on direct financing lease and contractual override	904	
Acquisition of contracts	(59,009)	
Net cash used in investing activities	(152,765)	(98,593)
Cash flows from financing activities:		
Proceeds from loans	73,000	335,000
Repayment of loans	(23,108)	(202,826)
Deferred financing costs		(1,052)
Repayment of obligation related to acquisitions	(500)	(4,025)
Costs associated with equity transactions		(140)
Distributions to partners	(121,582)	(116,845)
Net cash provided by (used in) financing activities	(72,190)	10,112
Net increase (decrease) in cash and cash equivalents	(92,948)	50,199
Cash and cash equivalents at beginning of period	214,922	95,506
Cash and cash equivalents at end of period	$ 121,974	$ 145,705

Supplemental cash flow information:		
Cash paid during the period for interest	$ 26,976	$ 20,859
Non-cash activities:		
Obligation related to purchase of reserves and infrastructure	$	$ 4,100

The accompanying notes are an integral part of these financial statements.

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(In thousands, except unit data)

	Common Units		General Partner	Non-Controlling Interest	Accumulated Other Comprehensive Income (Loss)	
	Units	Amounts	Amounts	Amounts		Total
Balance at December 31, 2011	106,027,836	$ 629,253	$ 10,517	$ 5,638	$ (493)	$ 644,915
Distributions		(116,630)	(2,380)	(2,572)		(121,582)
Net income		99,222	2,025			101,247
Loss on interest hedge					23	23
Comprehensive income					23	101,270
Balance at June 30, 2012	106,027,836	$ 611,845	$ 10,162	$ 3,066	$ (470)	$ 624,603

The accompanying notes are an integral part of these financial statements.

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NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Organization

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for future periods.

You should refer to the information contained in the footnotes included in Natural Resource Partners L.P. s 2011 Annual Report on Form 10-K in connection with the reading of these unaudited interim consolidated financial statements. We restated certain income-related items with respect to 2011 to properly reflect them in the correct quarter. Please read Note 17. Supplemental Financial Information (unaudited) in our Form 10-K for the year ended December 31, 2011 for additional information related to the restatements of our prior year financial data.

The Partnership engages principally in the business of owning, managing and leasing mineral properties in the United States. The Partnership owns coal reserves in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. The Partnership also owns aggregate reserves in several states across the country. The Partnership does not operate any mines on its properties, but leases reserves to experienced operators under long-term leases that grant the operators the right to mine the Partnership s reserves in exchange for royalty payments. Lessees are generally required to make payments based on the higher of a percentage of the gross sales price or a fixed royalty per ton, in addition to a minimum payment.

In addition, the Partnership owns transportation and preparation equipment, other mineral related rights and oil and gas properties on which it earns revenue.

The general partner of the Partnership is NRP (GP) LP, a Delaware limited partnership, whose general partner is GP Natural Resource Partners LLC, a Delaware limited liability company.

2. Recent Accounting Pronouncements

In June 2011, the FASB amended the presentation of comprehensive income. The amendments in this update gave the Partnership the option to present the total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The amendments in this update also require the Partnership to present changes in accumulated other comprehensive income by component in the statement of unitholders equity or in the notes to the financial statements. These amendments are effective for fiscal years and interim periods within those years, beginning on or after December 15, 2011. The Partnership adopted this amendment on January 1, 2012 and elected to present other comprehensive income in a single continuous statement, Consolidated Statements of Comprehensive Income. The Partnership also elected to present changes in accumulated other comprehensive income in the Consolidated Statements of Partners Capital.

In May 2011, the FASB amended fair value measurement and disclosure requirements. The amendments result in common fair value measurement and disclosure requirements in U.S. GAAP and International Financial Reporting Standards (IFRSs). Some of the amendments clarify the FASB s intent about the application of existing fair value measurement requirements. Other amendments change a particular principal or requirement for measuring fair value or for disclosing information about fair value measurements. These amendments are effective for fiscal years and interim periods within those years, beginning on or after December 15, 2011. The Partnership adopted this amendment on January 1, 2012. The amendment did not have a material impact on its financial position, results of operations, cash flows or notes to the financial statements.

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Partnership s financial position, results of operations and cash flows.

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3. Significant Acquisitions

Oklahoma Oil and Gas. From December 2011 through June 2012, the Partnership acquired approximately 19,200 net mineral acres located in the Mississippian Lime oil play in Northern Oklahoma for approximately $63.9 million, of which 15,600 net mineral acres were acquired during the first six months of 2012 for $51.3 million.

Sugar Camp. In March 2012, the Partnership acquired from Sugar Camp Energy, an affiliate of the Cline Group, the rail loadout and associated infrastructure assets at the Sugar Camp mine in Illinois for total consideration of $50.0 million. At the time of the acquisition, the Partnership also entered into a lease agreement related to the rail loadout and associated facilities that has been accounted for as a direct financing lease. The lease provides for payments based upon tons of coal transported over the facilities subject to quarterly recoupable minimum payments of $1.25 million. The lease is for a term of 20 years but may be extended by the lessee. Total projected remaining payments under the lease at June 30, 2012 are $98.3 million with unearned income of $48.6 million. The unearned income will be reflected as transportation fees over the term of the lease using the effective interest method. Any amounts in excess of the contractual minimums will be recorded as transportation fees as earned. The net amount receivable under the lease as of June 30, 2012 was $49.7 million, of which $1.1 million is included in accounts receivable affiliates while the remaining is located in long-term contracts receivable - affiliate. The Partnership recognized $1.4 million in transportation fees during the six months ended June 30, 2012 related to this lease.

In a separate transaction, the Partnership acquired, from Ruger, LLC, an affiliate of the Cline Group, a contractual overriding royalty interest for $8.9 million that will provide for payments based upon production from specific tons at the Sugar Camp operations. This overriding royalty was accounted for as a financing arrangement and is reflected as an affiliate receivable. The payments the Partnership receives with respect to the overriding royalty will be reflected partially as a return of the initial investment and partially as override revenue over the life of the contract using the effective interest method based upon actual production and adjusted periodically for differences in projected and actual production. The net amount receivable under the agreement as of June 30, 2012 was $7.2 million of which $0.4 million is included in accounts receivable affiliates while the remaining is located in long-term contracts receivable - affiliate. The Partnership recognized $0.4 million in overriding royalty during the six months ended June 30, 2012.

Colt. In September 2009, the Partnership signed a definitive agreement to acquire approximately 200 million tons of coal reserves related to the Deer Run Mine in Illinois from Colt, LLC, an affiliate of the Cline Group, through several separate transactions for a total purchase price of $255 million. As of June 30, 2012, the Partnership had acquired approximately 118.1 million tons of reserves for approximately $215 million, including $40.0 million paid during the first six months of 2012. The final closing is anticipated to occur in August of 2012 and will be associated with completion of certain milestones related to the new mine.

4. Plant and Equipment

The Partnership s plant and equipment consist of the following:

	June 30, 2012	December 31, 2011
	(In thousands)	
	(Unaudited)	
Plant construction in process	$ 571	$ 78
Plant and equipment at cost	67,175	67,175
Less accumulated depreciation	(24,779)	(21,068)
Net book value	$ 42,967	$ 46,185

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	Six months ended June 30, 2012	2011
	(In thousands) (Unaudited)	
Total depreciation expense on plant and equipment	$ 3,711	$ 4,235

5. Coal and Other Mineral Rights

The Partnership s coal and other mineral rights consist of the following:

	June 30, 2012	December 31, 2011
	(In thousands)	
	(Unaudited)	
Coal and other mineral rights	$ 1,734,284	$ 1,645,451
Less accumulated depletion and amortization	(409,630)	(387,950)
Net book value	$ 1,324,654	$ 1,257,501

	Six months ended June 30, 2012	2011
	(In thousands) (Unaudited)	
		(Restated)
Total depletion and amortization expense on coal and other mineral rights	$ 21,680	$ 22,310

6. Intangible Assets

Amounts recorded as intangible assets along with the balances and accumulated amortization are reflected in the table below:

	June 30, 2012	December 31, 2011
	(In thousands)	
	(Unaudited)	
Contract intangibles	$ 89,420	$ 89,420
Less accumulated amortization	(16,448)	(14,256)
Net book value	$ 72,972	$ 75,164

	Six months ended June 30, 2012	2011

	(In thousands)	
	(Unaudited)	
Total amortization expense on intangible assets	$ 2,192	$ 5,203

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The estimates of future amortization expense relating to intangible assets for the periods indicated below are based on current mining plans, which are subject to revision in future periods.

	Estimated Amortization Expense (In thousands) (Unaudited)
Remainder of 2012	$ 1,574
For year ended December 31, 2013	4,664
For year ended December 31, 2014	4,500
For year ended December 31, 2015	4,500
For year ended December 31, 2016	4,500

7. Long-Term Debt

Long-term debt consists of the following:

	June 30, 2012	December 31, 2011
	(In thousands)	
$300 million floating rate revolving credit facility, due August 2016	$ 73,000	$
5.55% senior notes, with semi-annual interest payments in June and December, maturing June 2013	35,000	35,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018	27,700	32,317
8.38% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2013, maturing in March 2019	150,000	150,000
5.05% senior notes, with semi-annual interest payments in January and July, with annual principal payments in July, maturing in July 2020	69,230	69,230
5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021	1,731	1,922
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	30,300	33,600
4.73% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2023	75,000	75,000
5.82% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2024	180,000	195,000
8.92% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2014, maturing in March 2024	50,000	50,000
5.03% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2026	175,000	175,000
5.18% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2026	50,000	50,000
Total debt	916,961	867,069
Less current portion of long term debt	(87,230)	(30,801)
Long-term debt	$ 829,731	$ 836,268

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Principal payments due in:

	Senior Notes	Credit Facility (In thousands)	Total
Remainder of 2012	$ 7,692	$	$ 7,692
2013	87,230		87,230
2014	80,983		80,983
2015	80,983		80,983
2016	80,983	73,000	153,983
Thereafter	506,090		506,090
	$ 843,961	$ 73,000	$ 916,961

The senior note purchase agreement contains covenants requiring our operating subsidiary to:

Maintain a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the note purchase agreement) of no more than 4.0 to 1.0 for the four most recent quarters;

not permit debt secured by certain liens and debt of subsidiaries to exceed 10% of consolidated net tangible assets (as defined in the note purchase agreement); and

maintain the ratio of consolidated EBITDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.0.

The 8.38% and 8.92% senior notes also provide that in the event that the Partnership s leverage ratio exceeds 3.75 to 1.00 at the end of any fiscal quarter, then in addition to all other interest accruing on these notes, additional interest in the amount of 2.00% per annum shall accrue on the notes for the two succeeding quarters and for as long thereafter as the leverage ratio remains above 3.75 to 1.00.

The Partnership made principal payments of $23.1 million on its senior notes during the six months ended June 30, 2012.

At June 30, 2012, the Partnership had $73 million outstanding on its revolving credit facility; while at December 31, 2011 the Partnership did not have any outstanding balance. The weighted average interest rates for the six months ended June 30, 2012 and year ended December 31, 2011 were 2.29% and 1.83%, respectively. The Partnership incurs a commitment fee on the undrawn portion of the revolving credit facility at rates ranging from 0.18% to 0.40% per annum. The facility includes an accordion feature whereby the Partnership may request its lenders to increase their aggregate commitment to a maximum of $500 million on the same terms.

The revolving credit facility contains covenants requiring the Partnership to maintain:

a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the credit agreement) not to exceed 4.0 to 1.0 and,

a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease operating expense) of not less than 3.5 to 1.0 for the four most recent quarters.

The Partnership was in compliance with all terms under its long-term debt as of June 30, 2012.

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8. Fair Value

The Partnership s financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amount of the Partnership s financial instruments included in accounts receivable and accounts payable approximates their fair value due to their short-term nature except for the accounts receivable affiliate relating to the Sugar Camp override that includes both current and long-term portions. The Partnership s cash and cash equivalents include money market accounts and are considered a Level 1 measurement. The fair market value and carrying value of the contractual override and long-term senior notes are as follows:

	Fair Value As Of		Carrying Value As Of	
	June 30, 2012	December 31, 2011	June 30, 2012	December 31, 2011
	(In thousands)			
	(Unaudited)		(Unaudited)	
Assets				
Accounts receivable - affiliates, current and long-term	$ 8,487	$	$ 7,151	$
Liabilities				
Long-term debt, current and long-term	$ 899,091	$ 915,959	$ 843,961	$ 867,069

The fair value of both the accounts receivable - affiliates and long-term debt is estimated by management using comparable term risk-free treasury issues with a market rate component determined by current financial instruments with similar characteristics which is a Level 3 measurement. Since the Partnership s credit facility is variable rate debt, its fair value approximates its carrying amount.

9. Related Party Transactions

Reimbursements to Affiliates of our General Partner

The Partnership s general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with the partnership agreement, the general partner and its affiliates are reimbursed for expenses incurred on the Partnership s behalf. All direct general and administrative expenses are charged to the Partnership as incurred. The Partnership also reimburses indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by our general partner and its affiliates. The Partnership had an amount payable to Quintana Minerals Corporation of $0.3 million at June 30, 2012 for services provided by Quintana to the Partnership and a payable of $0.1 million to Western Pocahontas Properties for services provided to the Partnership.

The reimbursements to affiliates of the Partnership s general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)			
	(Unaudited)			
Reimbursement for services	$ 2,404	$ 2,091	$ 4,927	$ 4,153

The Partnership also leases substantially all of two floors of an office building in Huntington, West Virginia from Western Pocahontas Properties and pays $0.5 million in lease payments each year through December 31, 2018.

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Cline Affiliates

Various companies controlled by Chris Cline lease coal reserves from the Partnership, and the Partnership provides coal transportation services to them for a fee. At June 30, 2012, Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest in the Partnership s general partner, as well as 16,686,672 common units. Revenues from the Cline affiliates are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands) (Unaudited)			
		(Restated)		(Restated)
Coal royalty revenues	$ 12,833	$ 6,704	$ 21,456	$ 15,883
Processing fees	528	492	1,030	1,193
Transportation fees	5,246	3,745	9,354	7,844
Minimums recognized as revenue			9,556	
Override revenue	768	228	1,694	679
Other revenue		2,990		2,990
	$ 19,375	$ 14,159	$ 43,090	$ 28,589

At June 30, 2012, the Partnership had amounts due from Cline affiliates totaling $66.8 million, of which $58.1 million was attributable to agreements relating to the recent Sugar Camp acquisition. See Note 3. Significant Acquisitions for further disclosure relating to the Sugar Camp agreements. The Partnership had received $50.7 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $13.7 million was received in the current year. The $9.6 million in minimums recognized as revenue during the first six months of 2012 was attributable to an agreement in 2012 by Gatling Ohio, LLC to relinquish its recoupment rights.

During 2011, the Partnership recognized a $3.0 million gain on a reserve exchange of over one million tons in Illinois with Williamson Energy. The fair value of the reserves was estimated using Level 3 cash flow approach. The expected cash flows were developed using estimated annual sales tons, forecasted sales prices and anticipated market royalty rates. The tons received will be fully mined during 2012, while the tons exchanged are not included in the current mine plans. The gain is located in Other revenues on the Consolidated Statements of Income.

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd., which controls several private equity funds focused on investments in the energy business. In connection with the formation of Quintana Capital, the Partnership adopted a formal conflicts policy that establishes the opportunities that will be pursued by the Partnership and those that will be pursued by Quintana Capital. The governance documents of Quintana Capital s affiliated investment funds reflect the guidelines set forth in NRP s conflicts policy.

A fund controlled by Quintana Capital owns a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart s 5-person board of directors. The Partnership owns and leases preparation plants to Taggart Global, which designs, builds and operates the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. The Partnership currently leases four facilities to Taggart. Revenues from Taggart are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands) (Unaudited)		(In thousands) (Unaudited)	

Processing fees	$ 2,311	$ 2,419	$ 3,657	$ 4,625

At June 30, 2012, the Partnership had accounts receivable totaling $1.2 million from Taggart.

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A fund controlled by Quintana Capital owns Kopper-Glo, a small coal mining company that is one of the Partnership s lessees with operations in Tennessee. Revenues from Kopper-Glo are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
	(Unaudited)		(Unaudited)	
Coal royalty revenues	$ 929	$ 419	$ 1,688	$ 753

The Partnership also had accounts receivable totaling $0.3 million from Kopper-Glo at June 30, 2012.

10. Commitments and Contingencies

Legal

The Partnership is involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, Partnership management believes these claims will not have a material effect on the Partnership s financial position, liquidity or operations.

Environmental Compliance

The operations that the Partnership s lessees conduct on the Partnership s properties are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. As an owner of coal reserves, as well as surface interests in some properties, the Partnership may be liable for environmental conditions occurring at the Partnership s properties. The terms of substantially all of the Partnership s leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. The Partnership makes regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. The Partnership believes that its lessees will be able to comply with existing regulations and does not expect any lessee s failure to comply with environmental laws and regulations to have a material impact on the Partnership s financial condition or results of operations. The Partnership also carries pollution liability insurance, and West Virginia has established a fund to satisfy any shortfall in the Partnership s lessees reclamation obligations, but this fund may not be sufficient to cover the Partnership s costs in the event that it is determined to be responsible for environmental contamination.

The Partnership s lessees regularly conduct reclamation work on the properties under lease to them. Because the Partnership is not the permittee of the operations on its properties, the Partnership is not responsible for the costs associated with the reclamation. However, the Partnership has received a Notice of Intent to File a Citizen Suit in connection with alleged selenium discharges from one of its properties in West Virginia that is leased to Alpha Natural Resources. Mining has now ceased on the property, but was originally conducted by Pittston Coal Company, which assigned the lease to Massey Energy, which subsequently merged with Alpha Natural Resources. The reclamation has been completed and the permits and bonding have been released, leading the plaintiffs to name the Partnership as the party responsible for the alleged discharge since the Partnership is the current owner of the property. Several other landowners have recently received similar notices, but these are the first instances of which the Partnership is aware that have targeted landowners rather than the mining companies. Although this particular litigation is not material to the Partnership, to the extent that the Partnership is not successful in defending these types of claims, does not receive indemnity under its leases or the claims are not covered by the Partnership s pollution liability insurance, or to the extent that these types of claims become more pervasive in the future, these issues could become material to NRP.

Acquisition

In conjunction with a definitive agreement, as of June 30, 2012, the Partnership may be obligated to purchase in excess of 75 million additional tons of coal reserves from Colt, LLC for an aggregate purchase price of $40.0 million in the third quarter as the final milestone is completed relating to construction of a new mine.

11. Major Lessees

Revenues from lessees that exceeded ten percent of total revenues for the periods are presented below:

	Three Months Ended June 30, (Dollars in thousands) (Unaudited)				Six Months Ended June 30, (Dollars in thousands) (Unaudited)			
	2012		2011 (Restated)		2012		2011 (Restated)	
	Revenues	Percent	Revenues	Percent	Revenues	Percent	Revenues	Percent
Alpha Natural Resources	$ 20,240	22%	$ 29,701	31%	$ 44,387	24%	$ 54,292	30%
The Cline Group	$ 19,375	21%	$ 14,159	15%	$ 43,090	24%	$ 28,589	16%

In the first six months of 2012, the Partnership derived over 48% of its total revenue from the two companies listed above. As a result, the Partnership has a significant concentration of revenues with those lessees, although in most cases, with the exception of the Williamson mine operated by an affiliate of the Cline group, the exposure is spread out over a number of different mining operations and leases. Cline s Williamson mine alone was responsible for approximately 12% of our total revenues for the first six months of 2012.

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12. Incentive Plans

GP Natural Resource Partners LLC adopted the Natural Resource Partners Long-Term Incentive Plan (the Long-Term Incentive Plan) for directors of GP Natural Resource Partners LLC and employees of its affiliates who perform services for the Partnership. The Compensation, Nominating and Governance (CNG) Committee of GP Natural Resource Partners LLC s board of directors administers the Long-Term Incentive Plan. Subject to the rules of the exchange upon which the common units are listed at the time, the board of directors and the CNG Committee of the board of directors have the right to alter or amend the Long-Term Incentive Plan or any part of the Long-Term Incentive Plan from time to time. Except upon the occurrence of unusual or nonrecurring events, no change in any outstanding grant may be made that would materially reduce the benefit intended to be made available to a participant without the consent of the participant.

Under the plan a grantee will receive the market value of a common unit in cash upon vesting. Market value is defined as the average closing price over the last 20 trading days prior to the vesting date. The CNG Committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of the Partnership, the general partner, or GP Natural Resource Partners LLC. If a grantee s employment or membership on the board of directors terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the CNG Committee provides otherwise.

A summary of activity in the outstanding grants during 2012 is as follows:

Outstanding grants at January 1, 2012	870,760
Grants during the year	272,150
Grants vested and paid during the year	(189,736)
Forfeitures during the year	(27,196)
Outstanding grants at June 30, 2012	925,978

Grants typically vest at the end of a four-year period and are paid in cash upon vesting. The liability fluctuates with the market value of the Partnership units and because of changes in estimated fair value determined each quarter using the Black-Scholes option valuation model. Risk free interest rates and volatility are reset at each calculation based on current rates corresponding to the remaining vesting term for each outstanding grant and ranged from 0.25% to 0.58% and 32.9% to 47.0%, respectively at June 30, 2012. The Partnership s average distribution rate of 6.84% and historical forfeiture rate of 3.80% were used in the calculation at June 30, 2012. The Partnership recorded expenses related to its plan to be reimbursed to its general partner of $0.9 million and $1.1 million and $2.4 million and $5.5 million for the three and six month periods ended June 30, 2012 and 2011, respectively. In connection with the Long-Term Incentive Plan, payments are typically made during the first quarter of the year. Payments of $6.6 million and $5.7 million were made during the six month periods ended June 30, 2012 and 2011, respectively.

In connection with the phantom unit awards granted since February 2008, the CNG Committee also granted tandem Distribution Equivalent Rights, or DERs, which entitle the holders to receive distributions equal to the distributions paid on the Partnership s common units. The DERs are payable in cash upon vesting but may be subject to forfeiture if the grantee ceases employment prior to vesting.

The unaccrued cost, associated with the unvested outstanding grants and related DERs at June 30, 2012, was $13.3 million.

13. Distributions

On May 14, 2012, the Partnership paid a quarterly distribution $0.55 per unit to all holders of common units on May 4, 2012.

14. Subsequent Events

The following represents material events that have occurred subsequent to June 30, 2012 through the time of the Partnership s filing with the Securities and Exchange Commission:

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Distributions

On July 19, 2012, the Partnership declared a distribution of $0.55 per unit to be paid on August 14, 2012 to unitholders of record on August 3, 2012.

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

The following discussion of the financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this filing and the financial statements and footnotes included in the Natural Resource Partners L.P. Form 10-K, as filed on February 29, 2012.

Executive Overview

Our Business

We engage principally in the business of owning, managing and leasing mineral properties in the United States. We own coal reserves in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. As of December 31, 2011, we owned or controlled approximately 2.3 billion tons of proven and probable coal reserves, and we also owned approximately 380 million tons of aggregate reserves in a number of states across the country. We do not operate any mines, but lease our reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell our reserves in exchange for royalty payments.

Our revenue and profitability are dependent on our lessees ability to mine and market our reserves. Most of our coal is produced by large companies, many of which are publicly traded, with experienced and professional sales departments. A significant portion of our coal is sold by our lessees under coal supply contracts that have terms of one year or more. In contrast, our aggregate properties are typically mined by regional operators with significant experience and knowledge of the local markets. The aggregates are sold at current market prices, which historically have increased along with the producer price index for sand and gravel. Over the long term, both our coal and aggregate royalty revenues are affected by changes in the market for and the market price of the commodities.

In our coal and aggregate royalty business, our lessees generally make payments to us based on the greater of a percentage of the gross sales price or a fixed royalty per ton of coal or aggregates they sell, subject to minimum monthly, quarterly or annual payments. These minimum royalties are generally recoupable over a specified period of time, which varies by lease, if sufficient royalties are generated from production in those future periods. We do not recognize these minimum royalties as revenue until the applicable recoupment period has expired or they are recouped through production. Until recognized as revenue, these minimum royalties are recorded as deferred revenue, a liability on our balance sheet.

During the first half of 2012, we generated $56.3 million of our revenues from sources other than coal and aggregate royalty revenues, compared to $41.8 million for the same period in 2011. The 35% increase was primarily due to the recognition as revenue of $9.6 million in minimum royalties associated with the Gatling Ohio mine as result of Gatling Ohio, LLC agreeing to relinquish its recoupment rights. We also received lease bonuses of approximately $2.5 million in the second quarter of 2012 that are included in our oil and gas royalty revenues and recognized $3.8 million in revenue in the second quarter from the sale of a right of way to the West Virginia Department of Highways for highway construction. We will receive the cash from this sale in the third quarter.

From December 2011 through the end of the second quarter, we spent approximately $63.9 million to acquire oil and gas mineral rights in the Mississippian Lime play in northern Oklahoma. A few of the properties are currently producing and added some revenue in the second quarter, but we expect oil and gas royalty revenues to continue to increase as more drilling occurs on properties included in our units. In addition to the minimums recognized as revenue, gains on sales of assets and the oil and gas royalty revenue, other sources of revenue include: processing and transportation fees; overriding royalties; wheelage payments; rentals; property tax revenue; and timber sales. The processing and transportation fees and overriding royalties are primarily derived from the coal-related assets.

Our Current Liquidity Position

Our credit facility does not mature until August 2016 and, as of June 30, 2012, we had $227 million in available capacity under the facility. In addition to the amounts available under our credit facility, we had approximately $122 million in cash at June 30, 2012. We believe that the combination of our capacity under our credit facility and our cash on hand gives us enough liquidity to meet our current financial needs.

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Other than a $35 million senior note that we intend to refinance prior to its maturity in 2013, we make annual principal payments on all our long-term debt. Although these annual payments will increase significantly beginning in 2013, we have no need to access the capital markets to pay off or refinance any of our senior note obligations other than the one note. As a result of our amortization program on our senior notes, our outstanding principal balance will be reduced on our long-term debt as our minerals are depleted. We do typically access the capital markets to refinance amounts outstanding under our credit facility as we approach the limits under that facility, the timing of which depends on the pace and size of our acquisition program.

Current Results

For the six months ended June 30, 2012, our lessees produced 26.9 million tons of coal and aggregates, generating $126.2 million in royalty revenues from our properties, and our total revenues were $182.5 million. We continue to have substantial exposure to metallurgical coal, from which we derived approximately 45% of our coal royalty revenues and 33% of the related production. The demand for domestic steel has been strong over the first half of the year, partially offsetting the declining demand for steel in the global markets.

The market for steam coal remained soft as expected in the first six months, with extremely low natural gas prices resulting in significant displacement of coal by gas for domestic power production. In addition, an unseasonably warm winter resulted in lower demand for coal and increased stockpiles at the utilities. Further, the federal government regulations dealing with air quality at power plants have led to the announcement of planned closures of a number of coal-fired power plants, which will have an impact on future demand. In response to these events, a number of coal companies reduced their production in the first six months of the year, which has resulted in lower production from our properties but has helped to sustain the prices received by our lessees.

Growth Through Acquisitions

We have continued to diversify our holdings by expanding our coal presence in the Illinois Basin and through additional aggregates and other mineral acquisitions, including oil and gas royalties. In addition to the Oklahoma oil and gas properties we acquired over the first six months of 2012, in March we acquired a coal rail loadout and associated infrastructure in Illinois and entered into a lease with Sugar Camp Energy pursuant to which we receive throughput fees for coal transported through our facility. We also acquired a contractual overriding royalty at Cline s Sugar Camp mine in Illinois following the start-up of the longwall operation at that mine.

Prior to the Sugar Camp acquisition in the first quarter, our expansion into Illinois was primarily related to development of greenfield mines by Cline. The investment that we have made in the Deer Run mine at Hillsboro through the acquisition of reserves from Colt is typical of this type of transaction. These projects take several years to reach full production, and it is difficult for us to forecast the timing of completion of the projects. We currently expect to make the final $40 million payment to Colt when the longwall commences operation in August of this year. We have been receiving significant minimum royalties with respect to the Hillsboro project. Although minimums provide cash to us that can be distributed to our limited partners, the minimums are generally not reported as revenue by us until recouped through production or at the end of the recoupment period.

In addition to our growth in the Illinois Basin and new oil and gas properties, we expect to see continued growth in the remainder of 2012 in our aggregates royalties through both new acquisitions and previously acquired properties that will be emerging out of the development phase later in the year.

Political, Legal and Regulatory Environment

The political, legal and regulatory environment continues to be difficult for the coal industry. The Environmental Protection Agency, or EPA, has used its authority to create significant delays in the issuance of new permits and the modification of existing permits. The continued uncertainty regarding the permitting of coal mines in Appalachia has led to substantial delays and increased costs for coal operators.

In addition to the increased oversight of the EPA, the Mine Safety and Health Administration, or MSHA, has increased its involvement in the approval of plans and enforcement of safety issues in connection with mining. The 2010 mine disaster at Massey s Upper Big Branch Mine has led to even more scrutiny by MSHA of our lessees operations, as well as additional mine safety legislation being considered by Congress. MSHA s involvement has increased the cost of mining due to more frequent citations and much higher fines imposed on our lessees as well as the overall cost of regulatory compliance. Combined with the difficult economic environment and the higher costs of mining in general, MSHA s recent increased participation in the mine development process could significantly delay the opening of new mines.

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The EPA is also using the existing Clean Air Act to regulate greenhouse gases. In April 2007, the U.S. Supreme Court rendered its decision in *Massachusetts v. EPA*, finding that the EPA has authority under the Clean Air Act to regulate carbon dioxide emissions from automobiles and can decide against regulation only if the EPA determines that carbon dioxide does not significantly contribute to climate change and does not endanger public health or the environment. In response to *Massachusetts v. EPA*, the EPA published a final rule that requires the reporting of greenhouse gas emissions from all sectors of the American economy, although reporting of emissions from underground coal mines and coal suppliers as originally proposed has been deferred pending further review. In December 2009, EPA determined that six greenhouse gases, including carbon dioxide and methane, endanger the public health and welfare of current and future generations. In the same rulemaking, EPA found that emission of greenhouse gases from new motor vehicles and their engines contribute to greenhouse gas pollution. Although *Massachusetts v. EPA* did not involve the EPA s authority to regulate greenhouse gas emissions from stationary sources, such as coal-fueled power plants, the decision will impact the regulation of stationary sources. Several petitioners challenged the EPA s findings in the Washington D.C. Circuit Court of Appeals, but in June 2012 the D.C. Circuit Court upheld all of the regulations promulgated by the EPA. The petitioners have not yet indicated as to whether they intend to appeal the ruling of the D.C. Circuit Court.

Distributable Cash Flow

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Because distributable cash flow is a significant liquidity metric that is an indicator of our ability to generate cash flows at a level that can sustain or support an increase in quarterly cash distributions paid to our partners, we view it as the most important measure of our success as a company. Distributable cash flow is also the quantitative standard used in the investment community with respect to publicly traded partnerships.

Our distributable cash flow represents cash flow from operations, proceeds from sale of assets and return on direct financing lease and contractual override less actual principal payments and cash reserves set aside for scheduled principal payments on our senior notes. Although distributable cash flow is a non-GAAP financial measure, we believe it is a useful adjunct to net cash provided by operating activities under GAAP. Distributable cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities. Distributable cash flow may not be calculated the same for NRP as for other companies. A reconciliation of distributable cash flow to net cash provided by operating activities is set forth below.

Reconciliation of GAAP Net cash provided by operating activities

to Non-GAAP Distributable cash flow

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands) (Unaudited)			
Net cash provided by operating activities	$ 82,522	$ 91,646	$ 132,007	$ 138,680
Less scheduled principal payments	(7,917)	(8,633)	(23,108)	(23,826)
Less reserves for future principal payments	(13,058)	(7,700)	(26,116)	(15,759)
Add reserves used for scheduled principal payments	7,917	8,633	23,108	23,826
Return on direct financing lease and contractual override	904		904	
Proceeds from sale of assets	285	1,000	285	1,100
Distributable cash flow	$ 70,653	$ 84,946	$ 107,080	$ 124,021

Recent Acquisitions

We are a growth-oriented company and have closed a number of acquisitions over the last several years. Our most recent acquisitions are briefly described below.

Oklahoma Oil and Gas. From December 2011 through June 2012, we acquired approximately 19,200 net mineral acres located in the Mississippian Lime oil play in Northern Oklahoma for approximately $63.9 million.

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Sugar Camp. In March 2012, we acquired the rail loadout associated infrastructure assets for $50.0 million and a contractual overriding royalty for $8.9 million interest on certain tonnage at the Sugar Camp mine in Illinois. The rail loadout and infrastructure assets were purchased from Sugar Camp Energy, LLC and the contractual overriding royalty interest was purchased from Ruger, LLC, both affiliates of the Cline Group.

Colt. Between September 2009 and March 2012, we had acquired approximately 118.1 million tons of an estimated total of 200 million tons of coal reserves related to the Deer Run Mine in Illinois from Colt, LLC, an affiliate of the Cline Group, for approximately $215 million of the $255 million purchase price. The final closing is anticipated to occur in August of 2012.

Litz-Moore. In March 2012, we acquired metallurgical coal reserves adjacent to current NRP holdings in Virginia for $2.8 million.

Royal. In July 2011, we acquired approximately 44,000 acres of coal reserves and coal bed methane located in Pennsylvania and Illinois from Royal Oil and Gas Corporation for $8.0 million.

NBR Sand. In June 2011, we acquired an overriding royalty interest in approximately 711 acres of frac sand reserves near Tyler, Texas for $16.5 million.

East Tennessee Materials. In March 2011, we acquired approximately 500 acres of mineral and surface rights related to limestone reserves in Cleveland, Tennessee near Chattanooga for $4.7 million.

CALX Resources. In February 2011, we acquired approximately 500 acres of mineral and surface rights related to limestone reserves on the Tennessee River near Paducah, Kentucky for $16.0 million.

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Results of Operations

	Three Months Ended June 30, 2012	2011	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
		(Unaudited)		
		(Restated)		
Coal:				
Coal royalty revenues				
Appalachia				
Northern	$ 4,689	$ 5,180	$ (491)	(9)%
Central	38,403	55,119	(16,716)	(30)%
Southern	6,718	3,447	3,271	95%
Total Appalachia	49,810	63,746	(13,936)	(22)%
Illinois Basin	12,912	6,225	6,687	107%
Northern Powder River Basin	310	1,120	(810)	(72)%
Gulf Coast	(154)	151	(305)	(202)%
Total	$ 62,878	$ 71,242	$ (8,364)	(12)%
Production (tons)				
Appalachia				
Northern	1,651	1,199	452	38%
Central	6,507	8,023	(1,516)	(19)%
Southern	835	472	363	77%
Total Appalachia	8,993	9,694	(701)	(7)%
Illinois Basin	2,910	1,758	1,152	66%
Northern Powder River Basin	126	425	(299)	(70)%
Gulf Coast	(47)	151	(198)	(131)%
Total	11,982	12,028	(46)	NM
Average gross royalty per ton				
Appalachia				
Northern	$ 2.84	$ 4.32	$ (1.48)	(34)%
Central	5.90	6.87	(0.97)	(14)%
Southern	8.05	7.30	0.75	10%
Total Appalachia	5.54	6.58	(1.04)	(16)%
Illinois Basin	4.44	3.54	0.90	25%
Northern Powder River Basin	2.46	2.64	(0.18)	(7)%
Gulf Coast	NM	1.00	NM	NM
Combined average gross royalty per ton	$ 5.25	$ 5.92	$ (0.67)	(11)%
Aggregates:				
Royalty revenue	$ 1,702	$ 1,737	$ (35)	(2)%
Aggregate royalty bonus	$	$ 94	$ (94)	(100)%
Production	1,447	1,671	(224)	(13)%
Average base royalty per ton	$ 1.18	$ 1.04	$ 0.14	13%
Oil and Gas:				
Oil and gas royalties	$ 4,078	$ 1,996	$ 2,082	104%

* (NM) Not meaningful.

Coal Royalty Revenues and Production. Coal royalty revenues comprised approximately 69% and 74% of our total revenue for each of the three month periods ended June 30, 2012 and 2011, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Coal royalty revenues decreased in the three month period ended June 30, 2012 compared to the same period of 2011 along with a production decrease of 7%. During the quarter ending June 30, 2012, 537,000 tons were produced on a 1960s era coal lease in Northern Appalachia where little or no production had occurred since our formation, and where the royalty rate per ton is

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very low. This caused the overall decrease in the average royalty per ton for Northern Appalachia to be negatively skewed. Except for this lease, production would have been nearly equal but coal royalty revenue would still have decreased due to the idling of the Gatling Ohio, LLC mine that occurred in the 4th quarter of 2011, which had a high per ton royalty. This decrease was partially offset by a lessee on our Beaver Creek property realizing higher sales prices. Production in the Central Appalachian region decreased due to some lessees choosing to idle mines or mining units during the quarter and some mines moving to adjacent property. In general, pricing realized by the lessees was below the levels of the same quarter in 2011 causing a slightly higher percentage decrease in coal royalty revenue. The Southern Appalachia region had increased production and coal royalty revenue. This was primarily due to the Oak Grove preparation plant operating for the entire quarter after being temporarily idled in the second quarter of 2011 due to damage caused by a tornado.

Illinois Basin. Production and coal royalty revenue increased for the three months ended June 30, 2012 compared to the same period in 2011. The production increase was primarily due to sales from the Macoupin, Williamson and Hillsboro mines being higher during the quarter than in prior year. These increases were partially offset by lower production and revenue from Triad Mining, LLC and Knight Hawk Coal, LLC.

Northern Powder River Basin. Both production and coal royalty revenues decreased on our Western Energy property. The production decrease was due to the normal variations that occur due to the checkerboard nature of ownership.

Aggregates Royalty Revenues and Production. Aggregate revenue remained nearly constant but production decreased for the quarter ended June 30, 2012. The mix of production from leases with higher per ton royalty was the primary reason for revenue remaining flat despite lower production.

Oil and Gas Royalty Revenues. Oil and gas royalty revenues increased $2.1 million when compared to the three months ended June 30, 2011. Results for the second quarter of 2012 included lease bonuses of approximately $2.5 million on two of our BRP LLC properties. We did not receive any bonuses in the second quarter of 2011. These bonuses more than offset lower natural gas prices in 2012.

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	Six Months Ended June 30, 2012	2011	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
	(Unaudited)	(Restated)		
Coal:				
Coal royalty revenues				
Appalachia				
Northern	$ 7,697	$ 9,861	$ (2,164)	(22)%
Central	80,475	100,561	(20,086)	(20)%
Southern	11,021	8,188	2,833	35%
Total Appalachia	99,193	118,610	(19,417)	(16)%
Illinois Basin	21,681	15,285	6,396	42%
Northern Powder River Basin	1,772	2,513	(741)	(29)%
Gulf Coast	148	199	(51)	(26)%
Total	$ 122,794	$ 136,607	$ (13,813)	(10)%
Production (tons)				
Appalachia				
Northern	4,052	2,374	1,678	71%
Central	13,041	15,350	(2,309)	(15)%
Southern	1,388	1,120	268	24%
Total Appalachia	18,481	18,844	(363)	(2)%
Illinois Basin	5,001	4,034	967	24%
Northern Powder River Basin	595	905	(310)	(34)%
Gulf Coast	20	191	(171)	(90)%
Total	24,097	23,974	123	1%
Average gross royalty per ton				
Appalachia				
Northern	$ 1.90	$ 4.15	$ (2.25)	(54)%
Central	6.17	6.55	(0.38)	(6)%
Southern	7.94	7.31	0.63	9%
Total Appalachia	5.37	6.29	(0.92)	(15)%
Illinois Basin	4.34	3.79	0.55	15%
Northern Powder River Basin	2.98	2.78	0.20	7%
Gulf Coast	7.40	1.04	6.36	NM
Combined average gross royalty per ton	$ 5.10	$ 5.70	$ (0.60)	(11)%
Aggregates:				
Royalty revenue	$ 3,418	$ 2,931	$ 487	17%
Aggregate royalty bonus		$ 94	(94)	100%
Production	2,814	2,936	(122)	(4)%
Average base royalty per ton	$ 1.21	$ 1.00	$ 0.21	21%
Oil and Gas:				
Oil and gas royalties	$ 5,466	$ 4,988	$ 478	10%

* (NM) Not meaningful.

Coal Royalty Revenues and Production. Coal royalty revenues comprised approximately 67% and 75% of our total revenue for each of the six month periods ended June 30, 2012 and 2011, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Both production and coal royalty revenues decreased in the six month period ended June 30, 2012 compared to the same period of 2011. During the six months ending June 30, 2012, we had approximately 1.7 million tons of production on a 1960s era coal lease in Northern Appalachia where little or no production had occurred since our formation, and where the royalty rate per ton is very low. This caused the overall decrease in the average royalty per ton for Northern Appalachia to be negatively skewed. Except for this lease, production would have been nearly the same but coal royalty revenue would have decreased due to the idling of the Gatling Ohio, LLC mine that occurred in the fourth quarter of 2011, which had a high per ton royalty. Production in the Central Appalachian region decreased due to some lessees choosing to idle mines or mining units during the first six months and some mines moving to adjacent property. In general, pricing realized by the lessees was at or below the levels of the same period in 2011 causing a slightly higher percentage decrease in coal royalty revenue. The Southern Appalachia region had increased production and coal royalty revenue. This was primarily due to the Oak Grove preparation plant resuming production after being temporarily idled in the second quarter of 2011 and gradually building its volume as it went through the process of restarting the plant.

Illinois Basin. Production and coal royalty revenue increased for the six months ended June 30, 2012 compared to the same period in 2011. The increased production and revenue were due to sales from the Macoupin and Williamson mines being higher during the six months ended June 30, 2012 compared to the same period in 2011 and production from the Hillsboro mine, which began shipments in the fourth quarter of 2011.

Northern Powder River Basin. Production and coal royalty revenues decreased on our Western Energy property. The production decrease was due to the normal variations that occur due to the checkerboard nature of ownership, but the lessee was able to realize a higher sales price, which partially offset the production decrease.

Aggregates Royalty Revenues and Production. Aggregate production decreased and revenue increased for the six months ended June 30, 2012, primarily due to some operations reducing production in response to market conditions. The revenue per ton increased due to the mix of production.

Oil and Gas Royalty Revenues. Oil and gas royalty revenues increased $0.5 million when compared to the six months ended June 30, 2011. Results for the first six months of 2012 include lease bonuses of $2.5 million while the same period of 2011 included a lease bonus of $0.7 million. Excluding the bonus for 2012 and 2011, oil and gas royalties decreased $1.4 million primarily due to lower natural gas prices in 2012.

Other Operating Results

In addition to coal and aggregate royalty revenues, we generated approximately 31% of our first six months of 2012 revenues from other sources, as compared to 23% for the same period of 2011. Other sources of revenue typically include: minimums recognized as revenue, processing and transportation fees; overriding royalties; wheelage payments; rentals; property tax revenue; and timber sales. In the first half of 2012, we realized $12.7 million in minimums recognized as revenue, of which $9.6 million was attributable to an agreement in 2012 by Gatling Ohio, LLC to relinquish its recoupment rights, resulting in current year revenue recognition. We also recognized other revenue of $3.8 million this quarter from the sale of a right of way to the West Virginia Department of Highways for highway construction.

Processing and Transportation Revenues. We generated $3.1 million in processing revenues for both of the quarters ended June 30, 2012 and 2011, and $5.3 million and $6.3 million for the six months ended June 30, 2012 and 2011, respectively. We own but do not operate the preparation plants, and receive a fee for minerals processed through them. The decrease in processing fees was a result of lower Central Appalachian production.

In addition to our preparation plants, we own handling and transportation infrastructure. In contrast to our typical royalty structure, we receive a fixed rate per ton for coal transported over these facilities. At the Williamson mine in Illinois, we operate handling and transportation infrastructure and have subcontracted out that responsibility to third parties. At the Shay No. 1 mine and the Sugar Camp mine, we own the infrastructure and lease it to Cline affiliates. We generated transportation fees from these assets of approximately $5.2 million and $3.7 million for the quarters ended June 30, 2012 and 2011, respectively and $9.4 million and $7.8 million for the six months ended June 30, 2012 and 2011, respectively. The increase in our transportation revenue is due to increased production on our Illinois Basin properties.

Operating costs and expenses. Included in total expenses are:

- Depreciation, depletion and amortization of $15.2 million and $17.4 million for the quarters ended June 30, 2012 and 2011, respectively and $27.6 million and $31.8 million for the six months ended June 30, 2012 and 2011, respectively. Depletion and amortization decreased approximately $2.2 million for the three months ended June 30, 2012 and $4.2 million for the six months ended June 30, 2012. The decrease was primarily related to lower depreciation, depletion and amortization on certain assets acquired from Gatling, LLC and Gatling Ohio, LLC that were impaired during the third and fourth quarters of 2011.

- General and administrative expenses were $7.0 million and $6.4 million for the quarters ended June 30, 2012 and 2011, respectively and $16.0 million and $16.6 million for the six months ended June 30, 2012 and 2011, respectively. The change in general and administrative expense is due to higher salaries for additional employees and higher consulting fees offset by lower accruals for our long-term incentive plan attributable to our lower unit price.

Interest Expense. Interest expense increased approximately $1.1 million for the three months ended June 30, 2012 and $4.1 million for the six month period ended June 30, 2012 over the same period in 2011. The increase reflects the issuance of new senior notes during 2011 at higher interest rates than our credit facility and additional borrowings outstanding on our credit facility in 2012.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

We satisfy our working capital requirements with cash generated from operations. Since our initial public offering, we have financed our property acquisitions with available cash, borrowings under our revolving credit facility, and the issuance of our senior notes and additional units. While our ability to satisfy our debt service obligations and pay distributions to our unitholders depends in large part on our future operating performance, our ability to make acquisitions will depend on prevailing economic conditions in the financial markets as well as the coal and aggregate industries and other factors, some of which are beyond our control. Our capital expenditures, other than for acquisitions, have historically been minimal.

Our credit ratios are within our debt covenants for both our credit facility and our outstanding senior notes. In addition, we are amortizing substantially all of our senior notes and have no immediate need to refinance. For a more complete discussion of factors that will affect our liquidity, please read Item 1A. Risk Factors in our Form 10-K for the year ended December 31, 2011. As of June 30, 2012, we had $227 million in available capacity under our credit facility and we also had approximately $122.0 million of cash. Our $35.0 million 5.55% senior note is due within the next twelve months. We intend to refinance this note prior to maturity.

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Net cash provided by operations for the six months ended June 30, 2012 and 2011 was $132.0 million and $138.7 million, respectively. The most significant portion of our cash provided by operations is generated from coal royalty revenues.

Net cash used in investing activities for the six months June 30, 2012 and 2011 was $152.8 million and $98.6 million, respectively. Substantially all of our investing activities consisted of acquiring reserves, plant and equipment and other rights.

Net cash flows used in financing activities for the six months ended June 30, 2012 was $72.2 million. During the first six months of 2012, we had proceeds from loans of $73.0 million offset by repayment of debt of $23.1 million and distributions paid of $121.6 million. During the same period for 2011, net cash provided by financing activities was $10.1 million, which included proceeds from loans of $335.0 million offset by debt repayments of $202.8 million and $116.8 million for distributions to partners.

Contractual Obligations and Commercial Commitments

Credit Facility. As of the date of this report we had $227 million available to us under the facility. Under an accordion feature in the credit facility, we may request our lenders to increase their aggregate commitment to a maximum of $500 million on the same terms. However, we cannot be certain that our lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, we may elect to bring new lenders into the facility, but cannot make any assurance that the additional credit capacity will be available to us on existing or comparable terms.

During 2012, our borrowings and repayments under our credit facility were as follows:

	Quarter Ending March 31	 June 30
	(In thousands) (Unaudited)	
Outstanding balance, beginning of period	$	$ 47,000
Borrowings under credit facility	47,000	26,000
Less: Repayments under credit facility		
Outstanding balance, ending period	$ 47,000	$ 73,000

Our obligations under the credit facility are unsecured but are guaranteed by our operating subsidiaries. We may prepay all loans at any time without penalty. Indebtedness under the revolving credit facility bears interest, at our option, at either:

- the Alternate Base Rate (as defined in the credit agreement) plus an applicable margin ranging from 0% to 1%; or
- the Adjusted LIBO Rate (as defined in the credit agreement) plus an applicable margin ranging from 1.00% to 2.25%.

We incur a commitment fee on the unused portion of the revolving credit facility at a rate ranging from 0.18% to 0.40% per annum.

The credit agreement contains covenants requiring us to maintain:

- a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the credit agreement) not to exceed 4.0 to 1.0; and
- a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease operating expense) not less than 3.5 to 1.0.

Senior Notes. NRP (Operating) LLC issued the senior notes listed below under a note purchase agreement as supplemented from time to time. The senior notes are unsecured but are guaranteed by our operating subsidiaries. We may prepay the senior notes at any time together with a make-whole amount (as defined in the note purchase agreement). If any event of default exists under the note purchase agreement, the noteholders will be able to accelerate the maturity of the senior notes and exercise other rights and remedies.

The senior note purchase agreement contains covenants requiring our operating subsidiary to:

Maintain a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the note purchase agreement) of no more than 4.0 to 1.0 for the four most recent quarters;

- not permit debt secured by certain liens and debt of subsidiaries to exceed 10% of consolidated net tangible assets (as defined in the note purchase agreement); and

- maintain the ratio of consolidated EBITDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.0.

Long-Term Debt

As of the date of this filing, our debt consisted of:

- $73.0 million of our $300 million floating rate revolving credit facility, due August 2016;
- $35.0 million of 5.55% senior notes due 2013;
- $27.7 million of 4.91% senior notes due 2018;
- $150.0 million of 8.38% senior notes due 2019;
- $69.2 million of 5.05% senior notes due 2020;
- $1.7 million of 5.31% utility local improvement obligation due 2021;
- $30.3 million of 5.55% senior notes due 2023;
- $75.0 million of 4.73% senior notes due 2023;
- $180.0 million of 5.82% senior notes due 2024;
- $50.0 million of 8.92% senior notes due 2024;
- $175.0 million of 5.03% senior notes due 2026; and
- $50.0 million of 5.18% senior notes due 2026.

Other than the 5.55% senior notes due 2013, which have only semi-annual interest payments, all of our senior notes require annual principal payments in addition to semi-annual interest payments. The scheduled principal payments on the 8.38% senior notes due in 2019 do not begin until March 2013, the scheduled principal payments on the 8.92% senior notes due in 2024 do not begin until March 2014, and the scheduled principal payments on the 4.73%, 5.03% and 5.18% senior notes do not begin until December 2014. We also make annual principal and interest payments on the utility local improvement obligation.

Shelf Registration Statement

In addition to our credit facility, on April 24, 2012 we filed an automatically effective shelf registration statement on Form S-3 with the SEC that is available for registered offerings of common units and debt securities. This shelf replaced our previous shelf registration statement, which expired at the end of February 2012. The amounts, prices and timing of the issuance and sale of any equity or debt securities will depend on market conditions, our capital requirements and compliance with our credit facility and senior notes.

Off-Balance Sheet Transactions

We do not have any off-balance sheet arrangements with unconsolidated entities or related parties and accordingly, there are no off-balance sheet risks to our liquidity and capital resources from unconsolidated entities.

Related Party Transactions

Reimbursements to our General Partner

Our general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with our partnership agreement, we reimburse our general partner and its affiliates for expenses incurred on our behalf. All direct general and administrative expenses are charged to us as incurred. We also reimburse indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by our general partner and its affiliates. We had an amount payable to Quintana Minerals Corporation of $0.3 million at June 30, 2012 for services provided by Quintana to NRP. We also had a payable of $0.1 million to Western Pocahontas Properties for services provided to NRP. Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

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The reimbursements to our general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)			
	(Unaudited)			
Reimbursement for services	$ 2,404	$ 2,091	$ 4,927	$ 4,153

For additional information, please read Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement in our annual report filed on Form 10-K for the year ended December 31, 2011.

We also lease substantially all of two floors of an office building in Huntington, West Virginia from Western Pocahontas at market rates. The terms of the lease were approved by our Conflicts Committee. We pay $0.5 million each year in lease payments.

Cline Affiliates

Various companies controlled by Chris Cline lease coal reserves from NRP, and we provide coal transportation services to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest in NRP s general partner, as well as 16,686,672 common units. Revenues from Cline affiliates are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)			
	(Unaudited)			
		(Restated)		(Restated)
Coal royalty revenues	$ 12,833	$ 6,704	$ 21,456	$ 15,883
Processing fees	528	492	1,030	1,193
Transportation fees	5,246	3,745	9,354	7,844
Minimums recognized as revenue			9,556	
Override revenue	768	228	1,694	679
Other revenue		2,990		2,990
	$ 19,375	$ 14,159	$ 43,090	$ 28,589

At June 30, 2012, we had amounts due from Cline affiliates totaling $66.8 million, of which $58.1 million was attributable to agreements relating to the recent Sugar Camp acquisition. As of June 30, 2012, we had received $50.7 million in minimum royalty payments to date that have not been recouped by Cline affiliates, of which $13.7 million was received in the current year. The $9.6 million in minimums recognized as revenue during the first six months of 2012 was attributable to an agreement in 2012 by Gatling Ohio, LLC to relinquish its recoupment rights.

During 2011, we recognized a $3.0 million gain on a reserve exchange of over one million tons in Illinois with Williamson Energy. The fair value of the reserves was estimated using Level 3 cash flow approach. The expected cash flows were developed using estimated annual sales tons, forecasted sales prices and anticipated market royalty rates. The tons received will be fully mined during 2012, while the tons exchanged are not included in the current mine plans. The gain is located in Other revenues on the Consolidated Statements of Income.

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd., which controls several private equity funds focused on investments in the energy business. In connection with the formation of Quintana Capital, we adopted a formal conflicts policy that establishes the opportunities that will be pursued by NRP and those that will be pursued by Quintana Capital. The governance documents of Quintana Capital s affiliated investment funds reflect the guidelines set forth in NRP s conflicts policy.

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A fund controlled by Quintana Capital owns a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart s 5-person board of directors. We own and lease preparation plants to Taggart Global, which designed, built and operates the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. We currently lease four facilities to Taggart. Revenues from Taggart are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
	(Unaudited)		(Unaudited)	
Processing revenues	$ 2,311	$ 2,419	$ 3,657	$ 4,625

At June 30, 2012, we had accounts receivable totaling $1.2 million from Taggart.

In June 2007, a fund controlled by Quintana Capital acquired Kopper-Glo, a small coal mining company that is one of our lessees with operations in Tennessee. Revenues from Kopper-Glo are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
	(Unaudited)		(Unaudited)	
Coal royalty revenues	$ 929	$ 419	$ 1,688	$ 753

We also had accounts receivable totaling $0.3 million from Kopper-Glo at June 30, 2012.

Environmental

The operations our lessees conduct on our properties are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. As an owner of coal reserves, as well as surface interests in some properties, we may be liable for environmental conditions occurring at our properties. The terms of substantially all of our leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify us against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. We make regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. We believe that our lessees will be able to comply with existing regulations and do not expect any lessee s failure to comply with environmental laws and regulations to have a material impact on our financial condition or results of operations. We also carry pollution liability insurance, and West Virginia has established a fund to satisfy any shortfall in our lessees reclamation obligations, but this fund may not be sufficient to cover our costs in the event we are determined to be responsible for environmental contamination.

Our lessees regularly conduct reclamation work on the properties under lease to them. Because we are not the permittee of the operations on our properties, we are not responsible for the costs associated with the reclamation. However, we have received a Notice of Intent to File a Citizen Suit in connection with alleged selenium discharges from one of our properties in West Virginia that is leased to Alpha Natural Resources. Mining has now ceased on the property, but was originally conducted by Pittston Coal Company, which assigned the lease to Massey Energy, which subsequently merged with Alpha Natural Resources. The reclamation has been completed and the permits and bonding have been released, leading the plaintiffs to name us as the party responsible for the alleged discharge since we are the current owners of the property. Several other landowners have recently received similar notices, but these are the first instances of which we are aware that have targeted landowners rather than the mining companies. Although this particular litigation is not material to NRP, to the extent that we are not successful in defending these types of claims, do not receive indemnity under our leases or the claims are not covered by our pollution liability insurance, or to the extent that these types of claims become more pervasive in the future, these issues could become material to NRP.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, which includes adverse changes in commodity prices and interest rates as discussed below:

Commodity Price Risk

We are dependent upon the effective marketing and efficient mining of our coal reserves by our lessees. Our lessees sell coal under various long-term and short-term contracts as well as on the spot market. A large portion of these sales are under long-term contracts. A substantial or extended decline in coal prices could materially and adversely affect us in two ways. First, lower prices may reduce the quantity of coal that may be economically produced from our properties. This, in turn, could reduce our coal royalty revenues and the value of our coal reserves. Second, even if production is not reduced, the royalties we receive on each ton of coal sold may be reduced. Additionally, volatility in coal prices could make it difficult to estimate with precision the value of our coal reserves and any coal reserves that we may consider for acquisition.

Interest Rate Risk

Our exposure to changes in interest rates results from our borrowings under our revolving credit facility, which are subject to variable interest rates based upon LIBOR. At June 30, 2012, we had $73 million in variable interest rate debt.

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Item 4. Controls and Procedures

NRP carried out an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of NRP management, including the Chief Executive Officer and Chief Financial Officer of the general partner of the general partner of NRP. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures are effective in providing reasonable assurance that (a) the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms, and (b) such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

No changes were made to our internal control over financial reporting during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II. Other Information

Item 1. Legal Proceedings

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes these claims will not have a material effect on our financial position, liquidity or operations.

Item 1A. Risk Factors

During the period covered by this report, there were no material changes from the risk factors previously disclosed in Natural Resource Partners L.P. s Form 10-K for the year ended December 31, 2011.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

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Item 6. Exhibits

4.1*	Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated March 6, 2012.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.
101*	The following financial information from the quarterly report on Form 10-Q of Natural Resource Partners L.P. for the quarter ended June 30, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Income, (iii) Consolidated Statements of Cash Flows, and (iv) Notes to Consolidated Financial Statements, tagged as blocks of text.

* Submitted herewith.

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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 and thereunto duly authorized.

NATURAL RESOURCE PARTNERS L.P.

By: NRP (GP) LP, its general partner
By: GP NATURAL RESOURCE

PARTNERS LLC, its general partner

Date:	August 7, 2012	By:	/s/ Corbin J. Robertson, Jr. **Corbin J. Robertson, Jr.,** **Chairman of the Board and** **Chief Executive Officer** **(Principal Executive Officer)**
Date:	August 7, 2012	By:	/s/ Dwight L. Dunlap **Dwight L. Dunlap,** **Chief Financial Officer and** **Treasurer** **(Principal Financial Officer)**
Date:	August 7, 2012	By:	/s/ Kenneth Hudson **Kenneth Hudson** **Controller** **(Principal Accounting Officer)**