NATURAL RESOURCE PARTNERS LP
Form 10-Q
November 07, 2013
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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 September 30, 2013

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):

x Large Accelerated Filer	¨ 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 November 7, 2013 there were 109,812,408 Common Units outstanding.

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Forward-Looking Statements

Statements included in this Quarterly Report on 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 and acquisitions, expected commencement dates of mining, projected quantities of future production by the lessees mining our reserves 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 speak only as of the date hereof and 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. See Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012 for important factors that could cause our actual results of operations or our actual financial condition to differ.

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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)

	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 99,675	$ 149,424
Accounts receivable, net of allowance for doubtful accounts	30,639	35,116
Accounts receivable affiliates	8,550	10,613
Other	281	1,042
Total current assets	139,145	196,195
Land	24,340	24,340
Plant and equipment, net	27,703	32,401
Mineral rights, net	1,382,864	1,380,473
Intangible assets, net	68,110	70,766
Equity and other unconsolidated investments	242,407	
Loan financing costs, net	11,936	4,291
Long-term contracts receivable affiliate	53,603	55,576
Other assets, net	527	630
Total assets	$ 1,950,635	$ 1,764,672
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 6,032	$ 3,693
Accounts payable affiliates	727	957
Current portion of long-term debt	56,175	87,230
Accrued incentive plan expenses current portion	7,522	7,718
Property, franchise and other taxes payable	5,126	7,952
Accrued interest	7,667	10,265
Total current liabilities	83,249	117,815
Deferred revenue	136,677	123,506
Accrued incentive plan expenses	8,981	8,865
Long-term debt	1,088,884	897,039

Partners capital:		
Common units outstanding (109,812,408 and 106,027,836)	621,363	605,019
General partner s interest	10,362	10,026
Non-controlling interest	1,416	2,845
Accumulated other comprehensive loss	(297)	(443)
Total partners capital	632,844	617,447
Total liabilities and partners capital	$ 1,950,635	$ 1,764,672

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Unaudited)		(Unaudited)	
Revenues and other income:				
Coal royalties	$ 52,305	$ 70,259	$ 164,957	$ 193,053
Equity and other unconsolidated investment income	7,238		22,168	
Aggregate royalties	2,566	1,643	5,869	5,061
Processing fees	1,377	1,641	3,886	6,905
Transportation fees	4,742	5,007	13,499	14,361
Oil and gas royalties	3,886	1,246	9,742	6,712
Property taxes	4,009	3,602	11,805	11,421
Minimums recognized as revenue	998	1,096	6,425	13,748
Override royalties	2,927	3,359	11,011	11,998
Other	2,189	6,322	14,011	13,452
Total revenues and other income	82,237	94,175	263,373	276,711
Operating expenses:				
Depreciation, depletion and amortization	17,852	14,485	50,025	42,066
Asset impairments			734	
General and administrative	7,305	8,225	27,769	24,204
Property, franchise and other taxes	4,234	4,853	12,810	13,640
Lease operating expense	483		483	
Transportation costs	455	446	1,242	1,446
Coal royalty and override payments	284	523	826	1,396
Total operating expenses	30,613	28,532	93,889	82,752
Income from operations	51,624	65,643	169,484	193,959
Other income (expense)				
Interest expense	(15,516)	(13,677)	(44,619)	(40,815)
Interest income	18	35	232	104
Income before non-controlling interest	36,126	52,001	125,097	153,248
Non-controlling interest				
Net income	$ 36,126	$ 52,001	$ 125,097	$ 153,248
Net income attributable to:				

General partner	$ 723	$ 1,040	$ 2,502	$ 3,065
Limited partners	$ 35,403	$ 50,961	$ 122,595	$ 150,183
Basic and diluted net income per limited partner unit	$ 0.32	$ 0.48	$ 1.12	$ 1.42
Weighted average number of units outstanding	109,812	106,028	109,507	106,028
Comprehensive income	$ 36,167	$ 52,015	$ 125,243	$ 153,285

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)

	Nine Months Ended September 30, 2013	2012
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 125,097	$ 153,248
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	50,025	42,066
Gain on reserve swap	(8,149)	
Equity and other unconsolidated investment income	(22,168)	
Distributions of earnings from unconsolidated investments	24,113	
Non-cash interest charge, net	1,454	453
Gain on sale of assets	(551)	(8,823)
Asset impairment	734	
Change in operating assets and liabilities:		
Accounts receivable	9,477	666
Other assets	864	369
Accounts payable and accrued liabilities	792	1,055
Accrued interest	(2,598)	(2,771)
Deferred revenue	13,331	11,867
Accrued incentive plan expenses	(80)	(3,544)
Property, franchise and other taxes payable	(2,826)	(714)
Net cash provided by operating activities	189,515	193,872
Cash flows from investing activities:		
Acquisition of land and mineral rights	(38,303)	(134,463)
Acquisition or construction of plant and equipment		(681)
Acquisition of equity interests	(293,077)	
Distributions from unconsolidated investments	48,833	
Proceeds from sale of assets	559	15,047
Return on direct financing lease and contractual override	841	2,399
Investment in direct financing lease		(59,009)
Net cash used in investing activities	(281,147)	(176,707)
Cash flows from financing activities:		
Proceeds from loans	547,020	103,000
Repayment of loans	(386,230)	(30,800)
Deferred financing costs	(9,061)	

Proceeds from issuance of units	75,000	
Capital contribution by general partner	1,531	
Costs associated with equity transactions	(60)	(59)
Repayment of obligation related to acquisitions		(500)
Distributions to partners	(186,317)	(181,309)
Net cash provided by (used in) financing activities	41,883	(109,668)
Net (decrease) in cash and cash equivalents	(49,749)	(92,503)
Cash and cash equivalents at beginning of period	149,424	214,922
Cash and cash equivalents at end of period	$ 99,675	$ 122,419
Supplemental cash flow information:		
Cash paid during the period for interest	$ 45,716	$ 43,113
Non-cash activities:		
Note receivable from sale of assets	$	$ 1,808

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, 2012	106,027,836	$ 605,019	$ 10,026	$ 2,845	$ (443)	$ 617,447
Issuance of common units	3,784,572	75,000				75,000
Capital contribution			1,531			1,531
Cost associated with equity transactions		(60)				(60)
Distributions		(181,191)	(3,697)	(1,429)		(186,317)
Net income		122,595	2,502			125,097
Interest rate swap from unconsolidated investments					108	108
Loss on interest hedge					38	38
Comprehensive income					146	125,243
Balance at September 30, 2013	109,812,408	$ 621,363	$ 10,362	$ 1,416	$ (297)	$ 632,844

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 nine months ended September 30, 2013 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 2012 Annual Report on Form 10-K in connection with the reading of these unaudited interim consolidated financial statements.

Natural Resource Partners L.P. (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.

The Partnership also owns various oil and gas interests that are located principally in the Appalachian Basin, Louisiana, Oklahoma, and the Williston Basin in North Dakota and Montana, and the Partnership manages infrastructure assets through its ownership of preparation plants and coal handling facilities. In January 2013, the Partnership purchased a non-controlling equity interest in OCI Wyoming, L.P. (OCI Wyoming), which operates a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming. See Note 3. Equity and Other Investments for more information concerning this acquisition.

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. Significant Accounting Policies Update

Reclassification

Certain reclassifications have been made to the prior year s financial statements.

Equity Investments

The Partnership accounts for non-marketable investments using the equity method of accounting if the investment gives it the ability to exercise significant influence over, but not control of, an investee. Significant influence generally exists if the Partnership has an ownership interest representing between 20% and 50% of the voting stock of the investee. Under the equity method of accounting, investments are stated at initial cost and are adjusted for subsequent additional investment and the proportionate share of earnings or losses and distributions. Furthermore, under the equity method of accounting, an investee company s accounts are not reflected within the Partnership s Consolidated Balance Sheets and Statements of Comprehensive Income. However, the Partnership s carrying value in an equity method investee company is reflected in the caption Equity and other unconsolidated investments in the Partnership s Consolidated Balance Sheets. The Partnership s share of the earnings or losses of the investee company is reflected in the Consolidated Statements of Comprehensive Income as revenues and other income under the caption Equity and other unconsolidated investment income. These earnings are generated from natural resources, which are considered part of the Partnership s core business activities consistent with its directly owned revenue generating activities.

The Partnership accounts for its non-marketable equity investments using the cost method of accounting if its ownership interest does not provide the ability to exercise significant influence over the investee or if the investment is not determined to be in-substance common stock. The inability to exert significant influence is generally presumed if the investment is less than 20% of the investee s voting securities.

The Partnership evaluates its equity investments for impairment when events or changes in circumstances indicate, in management s judgment, that the carrying value of such investment may have experienced other than temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment loss. No impairment losses have been recognized as of September 30, 2013.

Recent Accounting Pronouncements

In February 2013, the FASB amended the comprehensive income reporting requirements to require an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. The amendment requires an entity to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. The adoption did not have a material impact on 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 or cash flows.

3. Recent Acquisitions

Abraxas. On August 9, 2013, the Partnership completed the acquisition of non-operated working interests in 13,515 net acres within the Bakken/Three Forks play in North Dakota and Montana from Abraxas Petroleum. The Partnership accounted for the transaction in accordance with the FASB s provisions for business combinations. The identification of all assets acquired and liabilities assumed as well as the valuation process required for the allocation of the purchase price is not complete. Pending the final allocation, the assets acquired of approximately $38.3 million are included in mineral rights in the accompanying Consolidated Balance Sheets.

4. Equity and Other Investments

In the first quarter of 2013, the Partnership acquired non-controlling equity interests in OCI Co and OCI Wyoming comprised of a 48.51% general partner interest in OCI Wyoming and 20% of the common stock and 100% of the preferred stock of OCI Co. On the acquisition date, OCI Co was a conduit entity with its only asset a 1% interest in OCI Wyoming together with the right to receive an annual priority distribution. On July 18, 2013, the OCI companies were restructured resulting in the elimination of the common and preferred stock interests and an increase in the Partnership s interest in OCI Wyoming to 49%. The restructuring did not have a material impact on the operations, management, control or projected cash flows from the acquired OCI interests.

OCI Wyoming s operations consist of the mining of trona ore, which, when refined, becomes soda ash. All soda ash is sold through an affiliated sales agent to various domestic and European customers and to American Natural Soda Ash Corporation for export primarily to Asia and Latin America. All mining and refining activities take place in one facility located in the Green River Basin, Wyoming. These investments were acquired from Anadarko Holding Company and its subsidiary, Big Island Trona Company for $292.5 million. The acquisition was funded through a

$200 million term loan, the issuance of $76.5 million in equity (including a general partner contribution of $1.5 million), and $16 million in cash. The acquisition agreement provides for a net present value of up to $50 million in cumulative additional contingent consideration payable by the Partnership should certain performance criteria be met as defined in the purchase and sale agreement in any of the years 2013, 2014 or 2015.

The Partnership has engaged a valuation specialist to assist in identifying and valuing the assets and liabilities of OCI Wyoming at the date of acquisition, including the land, mine, plant and equipment as well as identifiable intangible assets, if any. Included in preliminary fair value adjustments, based on the most recent estimates, is an increase in the Partnership s proportionate fair value of property, plant and equipment of $78.7 million. Under the equity method of accounting, this amount is not reflected individually in the accompanying consolidated financial statements but is used to determine periodic charges to amounts reflected as income earned from the equity investments. For the quarter and nine months ended September 30, 2013, amortization of purchase adjustments of $0.7 and $1.9 million was recorded by the Partnership. In July 2013, the Partnership received a $44.8 million special distribution associated with OCI Wyoming s refinancing transaction. Until the valuations are complete, the remainder of the excess of the purchase price over the estimated fair value of the interests acquired has been attributed to goodwill; which is not subject to amortization. The allocation of the purchase price to the assets and liabilities is preliminary and subject to further adjustment, which may be material.

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The following summarized financial information as of September 30, 2013 and the results of operations for the three and nine-month periods then ended were taken from the OCI-prepared unaudited financial statements.

Operating results:

	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
	(In thousands) (Unaudited)	
Net sales	$ 105,567	$ 324,559
Gross profit	$ 20,545	$ 63,860
Net income	$ 16,323	$ 53,281
Income allocation to NRP s equity interests	$ 7,951	$ 24,113

Balance Sheet information:

	September 30, 2013 (In thousands) (Unaudited)
Current assets	$ 172,318
Property, plant and equipment	192,395
Other assets	1,319
Total assets	$ 366,032
Current liabilities	$ 36,167
Long term debt	155,000
Other liabilities	3,716
Capital	171,149
Total liabilities and capital	$ 366,032
Net book value of NRP s equity interests	$ 83,863
Excess of NRP s investment over net book value of NRP s equity interests	$ 158,544

5. Plant and Equipment

The Partnership s plant and equipment consist of the following:

	September 30, 2013 (Unaudited)	December 31, 2012
	(In thousands)	
Plant and equipment at cost	$ 55,271	$ 55,271
Less accumulated depreciation	(27,568)	(22,870)
Net book value	$ 27,703	$ 32,401

	Nine months ended September 30, 2013	2012
	(In thousands) (Unaudited)	
Total depreciation expense on plant and equipment	$ 4,698	$ 5,259

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6. Mineral Rights

The Partnership s mineral rights consist of the following:

	September 30, 2013	December 31, 2012
	(In thousands)	
	(Unaudited)	
Mineral rights	$ 1,860,405	$ 1,815,423
Less accumulated depletion and amortization	(477,541)	(434,950)
Net book value	$ 1,382,864	$ 1,380,473

	Nine months ended September 30, 2013	2012
	(In thousands) (Unaudited)	
Total depletion and amortization expense on mineral rights	$ 42,671	$ 33,547

7. Intangible Assets

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

	September 30, 2013	December 31, 2012
	(In thousands)	
	(Unaudited)	
Contract intangibles	$ 89,421	$ 89,421
Less accumulated amortization	(21,311)	(18,655)
Net book value	$ 68,110	$ 70,766

	Nine months ended September 30, 2013	2012

	(In thousands)	
	(Unaudited)	
Total amortization expense on intangible assets	$ 2,656	$ 3,264

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 2013	$ 1,166
For year ended December 31, 2014	3,690
For year ended December 31, 2015	3,830
For year ended December 31, 2016	3,830
For year ended December 31, 2017	3,830

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8. Long-Term Debt

As used in this Note 8, references to NRP LP refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC or any of Natural Resource Partners L.P. s subsidiaries. References to Opco refer to NRP (Operating) LLC and its subsidiaries. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP LP. NRP Finance Corporation (NRP Finance) is a wholly owned subsidiary of NRP LP and a co-issuer with NRP LP on the 9.125% senior notes.

Long-term debt consists of the following:

	September 30, 2013	December 31, 2012
	(In thousands)	
NRP LP Debt:		
$300 million 9.125% senior notes, with semi-annual interest payments in April and October, maturing October 2018, issued at 99.007%	$ 297,021	$
Opco Debt:		
$300 million floating rate revolving credit facility, due August 2016		148,000
$200 million floating rate term loan, due January 2016	99,000	
5.55% senior notes, with semi-annual interest payments in June and December, maturing June 2013		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	23,084	27,700
8.38% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2019	128,571	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	53,846	61,538
5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021	1,537	1,731
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	27,000	30,300
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	165,000	180,000
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

NRP Oil and Gas Debt:		
Reserve-based revolving credit facility due 2018		
Total debt	1,145,059	984,269
Less current portion of long term debt	(56,175)	(87,230)
Long-term debt	$ 1,088,884	$ 897,039

NRP LP Debt

Senior Notes. In September 2013, NRP LP, together with NRP Finance as co-issuer, issued $300 million of 9.125% senior notes at an offering price of 99.007% of par value. Net proceeds after expenses from the issuance of the senior notes of approximately $289.0 million were used to repay all of the outstanding borrowings under Opco s revolving credit facility and $91.0 million of Opco s term loan. The senior notes call for semi-annual interest payments on April 1 and October 1 of each year, beginning on April 1, 2014. The notes will mature on October 1, 2018.

The indenture for the senior notes contains covenants that, among other things, limit the ability of the NRP LP and certain of its subsidiaries to incur or guarantee additional indebtedness. Under the indenture, NRP LP and certain of its subsidiaries generally are not permitted to incur additional indebtedness unless, on a consolidated basis, the fixed charge coverage ratio (as defined in the indenture) is at least 2.0 to 1.0 for the four preceding full fiscal quarters. The ability of NRP LP and certain of its subsidiaries to incur additional indebtedness is further limited in the event the amount of indebtedness of NRP LP and certain of its subsidiaries that is senior to NRP LP s unsecured indebtedness exceeds certain thresholds.

Opco Debt

Senior Notes. Opco made principal payments of $87.0 million on its senior notes during the nine months ended September 30, 2013. The Opco senior note purchase agreement contains covenants requiring Opco to:

- Maintain a ratio of consolidated indebtedness to consolidated EBITDDA (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 EBITDDA 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 Opco 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.

Revolving Credit Facility. The weighted average interest rates for the debt outstanding under Opco s revolving credit facility for the nine months ended September 30, 2013 and year ended December 31, 2012 were 2.23% and 2.09%, respectively. Opco 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 Opco may request its lenders to increase their aggregate commitment to a maximum of $500 million on the same terms.

Opco s revolving credit facility contains covenants requiring Opco 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.

Term Loan Facility. During the first quarter of 2013, Opco also issued $200 million in term debt. The weighted average interest rate for the debt outstanding under the term loan for the nine months ended September 30, 2013 was

2.45%. Opco repaid $101 million in principal under the term loan during the third quarter of 2013. Repayment terms call for the remaining outstanding balance of $99 million to be paid on January 23, 2016. The debt is unsecured but guaranteed by the subsidiaries of Opco.

Opco s term loan contains covenants requiring Opco 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.

NRP Oil and Gas Debt

Revolving Credit Facility. In August 2013, NRP Oil and Gas entered into a 5-year, $100 million senior secured, reserve-based revolving credit facility in order to fund capital expenditure requirements related to the development of the non-operated working interests in oil and gas assets located in the Bakken/Three Forks play acquired on August 9, 2013. The credit facility has an initial borrowing base of $8.0 million and is secured by a first priority lien and security interest in substantially all of the assets of NRP Oil and Gas. At September 30, 2013, there were no borrowings outstanding under the credit facility.

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Indebtedness under the NRP Oil and Gas credit facility bears interest, at the option of NRP Oil and Gas, at either:

- the higher of (i) the prime rate as announced by the agent bank; (ii) the federal funds rate plus 0.50%; or (iii) LIBOR plus 1%, in each case plus an applicable margin ranging from 0.50% to 1.50%; or

- a rate equal to LIBOR, plus an applicable margin ranging from 1.75% to 2.75%.

NRP Oil and Gas will incur a commitment fee on the unused portion of the borrowing base under the credit facility at a rate ranging from 0.375% to 0.50% per annum.

The NRP Oil and Gas credit facility contains certain covenants, which, among other things, require the maintenance of:

- a total leverage ratio (defined as the ratio of the total debt of NRP Oil and Gas to its EBITDAX) of not more than 3.5 to 1.0; and

- a minimum current ratio of 1.0 to 1.0.

Consolidated Principal Payments

The consolidated principal payments due are set forth below:

	NRP LP Senior Notes	Senior Notes	OPCO Credit Facility	Term Loan	NRP Oil & Gas Credit Facility	Total
			(In thousands)			
Remainder of 2013	$	$	$	$	$	$
2014		80,983				80,983
2015		80,983				80,983
2016		80,983		99,000		179,983
2017		80,983				80,983
Thereafter	300,000[1]	425,107				725,107
	$ 300,000	$ 749,039	$	$ 99,000	$	$ 1,148,039

(1) The 9.125% senior notes due 2018 were issued at a discount.

NRP LP, Opco and NRP Oil and Gas were in compliance with all terms under their long-term debt as of September 30, 2013.

9. 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 affiliates relating to the Sugar Camp override and Taggart preparation plant sale 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, Taggart note receivable and long-term senior notes are as follows:

	Fair Value As Of		Carrying Value As Of	
	September 30, 2013	**December 31, 2012**	**September 30, 2013**	**December 31, 2012**
		(In thousands)		
	(Unaudited)		**(Unaudited)**	
Assets				
Sugar Camp override, current and long-term	$ 7,878	$ 8,817	$ 6,986	$ 7,495
Taggart plant sale, current and long-term	$	$ 1,668	$	$ 1,667
Liabilities				
Long-term debt, current and long-term	$ 1,074,008	$ 876,574	$ 1,046,059	$ 836,269

The fair value of the Sugar Camp override, Taggart plant sale 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 and term loan are both variable rate debt, their fair values approximate their carrying amounts.

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10. 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 $0.7 million at September 30, 2013 for services provided by Quintana 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands) (Unaudited)			
Reimbursement for services	$ 2,748	$ 2,303	$ 8,481	$ 7,230

The Partnership also leases an office building in Huntington, West Virginia from Western Pocahontas Properties and pays $0.6 million in lease payments each year through December 31, 2018.

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 September 30, 2013, Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owned a 31% interest in the Partnership s general partner, as well as 4,917,548 common units.

Revenues from the Cline affiliates are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands) (Unaudited)			
Coal royalty revenues	$ 14,968	$ 12,894	$ 39,527	$ 34,351

Processing fees	379	715	972	1,745
Transportation fees	4,742	5,008	13,499	14,362
Minimums recognized as revenue			3,477	9,556
Override revenue	957	1,075	2,735	2,768
Other revenue			8,149	
	$ 21,046	$ 19,692	$ 68,359	$ 62,782

At September 30, 2013, the Partnership had amounts due from Cline affiliates totaling $61.7 million, of which $56.7 million was attributable to agreements relating to Sugar Camp. The Partnership has received $69.2 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $16.3 million was received in the current year.

During 2013, the Partnership recognized an $8.1 million gain on a reserve swap in Illinois with Williamson Energy. This gain is reflected in the table above in the Other revenue line. 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 2013, while the tons exchanged are not included in the current mine plans.

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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 the Partnership s conflicts policy.

At September 30, 2013, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp., a coal mining company traded on the TSX Venture Exchange that is one of the Partnership s lessees in Tennessee. Corbin J. Robertson III, one of the Partnership s directors, is Chairman of the Board of Corsa. Revenues from Corsa are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands) (Unaudited)			
Coal royalty revenues	$ 1,249	$ 996	$ 3,403	$ 2,594

The Partnership also had accounts receivable totaling $0.4 million from Corsa at September 30, 2013.

11. 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 conducted on the Partnership s properties by its lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. As owner of surface interests in some properties, the Partnership may be liable for certain environmental conditions occurring at the surface 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 has neither incurred, nor is aware of, any material environmental charges imposed on it related to its properties as of September 30, 2013. The Partnership is not associated with any environmental contamination that may require remediation costs. During the second quarter of 2013, several citizen group lawsuits were filed against landowners alleging ongoing discharges of pollutants, including selenium, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property has been closed, the property has been reclaimed, and the state reclamation bond has been released. A subsidiary of NRP was named as a defendant in one of these lawsuits, but the suit has been dismissed. While it is too early to determine the merits or predict the outcome of any of these lawsuits, any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations.

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12. Major Lessees

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
	(Dollars in thousands) (Unaudited)							
	Revenues	Percent	Revenues	Percent	Revenues	Percent	Revenues	Percent
Alpha Natural Resources	$ 12,937	16%	$ 19,731	21%	$ 41,844	16%	$ 64,118	23%
The Cline Group	$ 21,046	26%	$ 19,692	21%	$ 68,359	26%	$ 62,782	23%

In the first nine months of 2013, the Partnership derived over 42% of its total revenues and other income from the two companies listed above. The first nine months of 2013 revenues received from the Cline Group include $8.1 million in revenues recorded in connection with a reserve swap at Cline s Williamson mine. Excluding the revenues from the reserve swap, revenues from the Cline Group accounted for approximately $60.3 million, or 23% of the Partnership s total revenues and other income for the first nine months of 2013. The Partnership has a significant concentration of revenues with Cline and Alpha, although in most cases, with the exception of the Williamson mine, the exposure is spread out over a number of different mining operations and leases. Cline s Williamson mine was responsible for approximately 14% of the Partnership s total revenues and other income for the first nine months of 2013, which amount includes the $8.1 million of revenue recorded from the reserve swap. Excluding revenues from the reserve swap, revenues from the Williamson mine accounted for approximately 11% of the Partnership s total revenues and other income for the first nine months of 2013.

13. 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 2013 is as follows:

Outstanding grants at January 1, 2013	912,314
Grants during the year	334,007
Grants vested and paid during the year	(231,917)
Forfeitures during the year	(8,450)
Outstanding grants at September 30, 2013	1,005,954

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 0.14% to 0.63% and 27.65% to 32.46%, respectively at September 30, 2013. The Partnership s average distribution rate of 7.24% and historical forfeiture rate of 4.20% were used in the calculation at September 30, 2013. The Partnership recorded expenses related to its plan to be reimbursed to its general partner of $0.6 million and

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$1.2 million and $7.5 million and $3.6 million for the three and nine months ended September 30, 2013 and 2012, respectively. In connection with the Long-Term Incentive Plan, payments are typically made during the first quarter of the year. Payments of $7.0 million and $6.6 million were made during the nine month period ended September 30, 2013 and 2012, 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 September 30, 2013 was $10.4 million.

14. Distributions

On August 14, 2013, the Partnership paid a quarterly distribution $0.55 per unit to all holders of common units on August 5, 2013.

15. Subsequent Events

The following represents material events that have occurred subsequent to September 30, 2013 through the time of the Partnership s filing of this Quarterly Report on Form 10-Q with the Securities and Exchange Commission:

Distributions

On October 22, 2013, the Partnership declared a distribution of $0.55 per unit to be paid on November 14, 2013 to unitholders of record on November 5, 2013.

Acquisition

On October 30, 2013, we signed a definitive agreement to acquire non-operated working interests in oil and gas properties in the Williston Basin of North Dakota, including properties producing from the Bakken/Three Forks play, from Sundance Energy, Inc. for $35.5 million, subject to customary purchase price adjustments at closing. Upon entering into the agreement, we paid a $3.6 million cash deposit into escrow.

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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. Annual Report on Form 10-K for the year ended December 31, 2012, as filed on February 28, 2013.

As used in this Item 2, unless the context otherwise requires: we, our and us refer to Natural Resource Partners L.P. and, where the context requires, our subsidiaries. References to NRP and Natural Resource Partners refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC or any of Natural Resource Partners L.P. s subsidiaries. References to Opco refer to NRP (Operating) LLC and its subsidiaries. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP. NRP Finance Corporation (NRP Finance) is a wholly owned subsidiary of NRP and a co-issuer with NRP on the 9.125% senior notes.

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, 2012, we owned or controlled approximately 2.4 billion tons of proven and probable coal reserves. 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. We also own and manage infrastructure assets that generate additional revenues for our company, particularly in the Illinois Basin.

In recent years, we have made a concerted effort to diversify our business. In connection with this effort, we have acquired approximately 500 million tons of aggregate reserves located in a number of states across the country. 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.

We have also acquired various interests in oil and gas properties that are located principally in the Appalachian Basin, Louisiana, Oklahoma, and in the Williston Basin in North Dakota and Montana. Oil and gas royalty revenues include production payments as well as bonus payments. Oil and gas royalty revenues are recognized on the basis of hydrocarbons sold by lessees and the corresponding revenues from those sales. Generally, the lessees make payments based on a percentage of the selling price. Some leases are subject to minimum annual payments or delay rentals. Revenues related to our non-operated working interests in oil and gas assets are recognized on the basis of our net revenue interests in hydrocarbons produced. We also have capital expenditure obligations associated with the non-operated working interests.

In 2013, we have made significant strides in our diversification effort through the following acquisitions:

In January, we purchased non-controlling equity interests in OCI Wyoming, L.P. (OCI Wyoming), an operator of a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming. Through September 30, 2013 we received $72.9 million in cash from our investment in OCI Wyoming. OCI Wyoming s operations consist of the mining of trona ore, which, when refined, becomes soda ash. All soda ash is sold through an OCI-affiliated sales agent to various domestic and European customers and to American Natural Soda Ash Corporation for export. All mining and refining activities take place in one facility located in the Green River Basin, Wyoming.

In August, we acquired non-operated working interests in producing oil and gas properties located in the Bakken/Three Forks play in the Williston Basin of North Dakota and Montana from Abraxas Petroleum Corporation for $38.3 million.

In October, we entered into a definitive agreement to acquire additional non-operated working interests in producing oil and gas properties in the Williston Basin of North Dakota, including properties producing from the Bakken/Three Forks play, from Sundance Energy, Inc. for approximately $35.5 million, subject to customary purchase price adjustments at closing.

For the nine months ended September 30, 2013, we recognized $98.4 million of revenues and other income from sources other than coal royalties, which primarily consisted of equity income from our investment in OCI Wyoming, oil and gas royalties, aggregates royalties, overriding royalties (which include coal and aggregates overrides), minimums recognized as revenue, and processing and transportation fees. The revenues that we recognize from minimums and processing/transportation are largely derived from coal-related businesses.

Our Current Liquidity Position

In September 2013, NRP, together with NRP Finance as co-issuer, sold $300.0 million of 9.125% Senior Notes due 2018 at an issue price of 99.007% of par value for net proceeds of $289 million. We used the net proceeds of the offering to repay all outstanding borrowings under Opco s revolving credit facility. Opco s revolving credit facility does not mature until August 2016 and, as of September 30, 2013, Opco had $300 million in available capacity under the facility. In August 2013, NRP Oil and Gas entered into a senior secured, reserve-based revolving credit facility with an initial $8.0 million borrowing base. As of September 30, 2013, NRP Oil and Gas had the full $8.0 million available for borrowing under its revolving credit facility. In addition to the amounts available under our revolving credit facilities, we had $99.7 million in cash at September 30, 2013. We believe that the combination of our capacity under our revolving credit facilities and our cash on hand gives us enough liquidity to meet our current financial needs. We typically access the capital markets to refinance amounts outstanding under our revolving credit facilities as we approach the limits under those facilities, the timing of which depends on the pace and size of our acquisition program and development capital expenditures associated with our oil and gas business.

We refinanced $7.0 million in principal payments on Opco s senior notes during the third quarter of 2013. Rather than pay the Opco senior notes principal payments that are due over the next twelve months with cash from operations, we might refinance some or all of these obligations as they come due.

We used $91.0 million of net proceeds from the September 2013 senior notes offering to repay principal on Opco s term loan. We also used a portion of the proceeds from the July 2013 $44.8 million special distribution from OCI Wyoming to repay $10.0 million of principal on Opco s term loan. Accordingly, Opco s next principal repayment obligation on the term loan is not until January 2016, when Opco will be required to repay the remaining principal amount outstanding thereunder of $99.0 million.

Current Results/Market Outlook

Our total revenues and other income for the first nine months of 2013 were $263.4 million, which was down approximately 5% when compared to the $276.7 million in total revenues and other income received for the first nine months of 2012. Although our total revenues and other income were only down 5%, our coal royalty revenues were down approximately 15% and our Central Appalachian coal royalty revenues were down over 32% in the same periods. We anticipated these declines and continue to see the benefits of our diversification efforts, as our coal royalty revenues from the Illinois Basin were up 17% in the first nine months of 2013, our investment in OCI Wyoming contributed $22.2 million in other income, and our oil and gas revenues increased 45% and continue to ramp up. As a result of these efforts, our distributable cash flow increased by 13% over the first nine months of 2012, primarily due to the $72.9 million in distributions that we received from OCI during the nine months ended September 30, 2013.

The decline in Central Appalachian coal royalty revenues resulted from continued weakness in both the metallurgical and steam markets, where prices remain depressed. While the outlook for the high cost Central Appalachian steam coal is challenging due to federal government regulations combined with low natural gas prices, we continue to have substantial exposure to metallurgical coal, from which we derived approximately 42% of our coal royalty revenues and 30% of the related production in the first nine months of 2013. The fourth quarter 2013 benchmark price for metallurgical coal is $152 per metric ton, which is up from the third quarter benchmark price of $145 per metric ton. The metallurgical coal recovery will not be a rapid one, but the global demand for steel continues to increase, and NRP will benefit as this market steadily improves. In addition, the Illinois Basin continues to increase production and is displacing Central Appalachian coal at some utilities. We are benefitting from the Illinois Basin growth through our relationship with Foresight Energy and the Cline Group.

OCI Wyoming s soda ash business has performed as we projected over the first nine months of 2013, but the increased liquidity associated with a refinancing transaction has resulted in higher than expected cash distributions to NRP in 2013, including a $44.8 million special distribution in July 2013. On a normalized basis, as a result of the OCI Resources LP initial public offering completed in September 2013, NRP anticipates receiving approximately $40.0 million per year of distributions from the OCI investment.

Growth Through Acquisitions

In 2012, we spent approximately $240 million to acquire additional assets that will help secure the future growth of the partnership. Included in these acquisitions were additional steam coal reserves and transportation infrastructure in Illinois, oil and gas mineral rights in Oklahoma, an overriding royalty on oil and gas reserves in the liquids-rich portion of the Marcellus Shale play, and an overriding royalty on frac sand reserves in Wisconsin. These efforts are reflective of our management s desire to continue to grow and diversify our assets and attempt to ensure the stability of future revenues and distributions to our unitholders.

In the first ten months of 2013, we continued to diversify our holdings through the acquisition of the interests in the OCI Wyoming soda ash business for $292.5 million, the acquisition of non-operated working interests in producing oil and gas properties in the Bakken/Three Forks play in the Williston Basin from Abraxas Petroleum Corporation for approximately $38.3 million, and the execution of a definitive agreement to acquire non-operated working interests in producing oil and gas properties in the Williston Basin, including properties producing from the Bakken/Three Forks play, from Sundance Energy, Inc. for approximately $35.5 million, subject to customary purchase price adjustments. We expect the Sundance acquisition to close in December 2013.

Political, Legal and Regulatory Environment

The political, legal and regulatory environment continues to be difficult for the coal industry. The Environmental Protection Agency (EPA) has used its authority to create significant delays in the issuance of new permits and the modification of existing permits, which has led to substantial delays and increased costs for coal operators. Furthermore, the federal courts have recently handed down several decisions that are adverse to the coal industry and, in a June 2013 speech, President Obama outlined his climate change policies, which include an initiative to limit carbon emissions by existing coal-fired utilities. In September 2013, EPA released proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules is that partial carbon capture and sequestration will be necessary to meet the emission standards for carbon dioxide for new fossil fuel-fired power plants. EPA is expected to issue proposed regulations on existing fossil fuel-fired power plants in June 2014. We expect that EPA s proposed regulations for both new and existing power plants will negatively affect the viability of coal-fired power generation, which will ultimately reduce coal consumption and the production of coal from our properties.

In addition to government action, private citizens groups have continued to be active in bringing lawsuits against operators, as well as challenging permits issued by the Army Corps of Engineers. During the second quarter of 2013, several citizen group lawsuits were filed against landowners alleging ongoing discharges of pollutants, including selenium, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property has been closed, the property has been reclaimed, and the state reclamation bond has been released. A subsidiary of NRP was named as a defendant in one of these lawsuits, but the suit has been dismissed. While it is too early to determine the merits or predict the outcome of any of these lawsuits, any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations.

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, distributions from unconsolidated investments, proceeds from sale of assets and returns on direct financing lease and contractual override. 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 us as for other companies. A reconciliation of distributable cash flow to net cash provided by operating activities is set forth below.

We have historically reduced our distributable cash flow by the amount of cash we have reserved for principal payments due on our senior notes in the next calendar year. However, to present our distributable cash flow more in line with MLP practice and because we intend to refinance some or all of the principal payments that are due in 2013 and 2014, beginning with our 2013 presentation, we no longer reduce distributable cash flow by reserves for future principal payments. We have changed our three and nine months ended September 30, 2012 calculations in the table below to be comparable with our presentation for 2013.

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Reconciliation of GAAP Net cash provided by operating activities

to Non-GAAP Distributable cash flow

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands) (Unaudited)			
Net cash provided by operating activities	$ 65,866	$ 61,865	$ 189,515	$ 193,872
Distributions from unconsolidated investments[1]	38,056		48,833	
Return on direct financing lease and contractual override	286	1,495	841	2,399
Proceeds from sale of assets	405	14,762	559	15,047
Distributable cash flow	$ 104,613	$ 78,122	$ 239,748	$ 211,318

(1) The cash distributions that NRP received were $46.0 million for the quarter and $72.9 million for the nine months ended September 30, 2013. The amounts included in the table reflect the difference between the cash distributions received and the other income we recorded from the OCI Wyoming investment, which are included in net cash provided by operating activities.

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.

Sundance. In October 2013, we signed a definitive agreement to acquire non-operated working interests in oil and gas properties in the Williston Basin of North Dakota, including properties producing from the Bakken/Three Forks play, from Sundance Energy, Inc. for approximately $35.5 million, subject to customary purchase price adjustments at closing.

Abraxas. In August 2013, we acquired non-operated working interests in producing oil and gas properties in the Bakken/Three Forks play in the Williston Basin of North Dakota and Montana from Abraxas Petroleum Corporation for $38.3 million.

OCI Wyoming. In January 2013, we acquired a non-controlling equity interest in OCI Wyoming from Anadarko Holding Company and its subsidiary, Big Island Trona Company for $292.5 million. The acquisition agreement provides for up to $50 million in additional contingent consideration payable by us should certain performance criteria be met as defined in the purchase and sales agreement in any of 2013, 2014 or 2015.

Marcellus Override. In December 2012, we acquired an overriding royalty interest on approximately 88,000 net acres of overriding royalty interests in oil and gas reserves located in the Marcellus Shale for $30.3 million.

Hi-Crush Override. In October 2012, we acquired an overriding royalty interest in frac sand reserves located on approximately 561 acres near Wyeville, Wisconsin for approximately $15.0 million.

Colt. Between September 2009 and September 2012, we acquired approximately 200 million tons of coal reserves related to the Deer Run Mine in Illinois from Colt, LLC, an affiliate of the Cline Group, for a total purchase price of $255 million.

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 $63.9 million.

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.

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

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Results of Operations

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
	(Unaudited)			
Coal:				
Royalty revenues				
Appalachia				
Northern	$ 2,882	$ 3,300	$ (418)	(13)%
Central	25,270	39,404	(14,134)	(36)%
Southern	5,571	9,672	(4,101)	(42)%
Total Appalachia	33,723	52,376	(18,653)	(36)%
Illinois Basin	15,364	13,205	2,159	16%
Northern Powder River Basin	2,279	4,493	(2,214)	(49)%
Gulf Coast	939	185	754	408%
Total	$ 52,305	$ 70,259	$ (17,954)	(26)%
Production (tons)				
Appalachia				
Northern	2,779	1,814	965	53%
Central	5,116	6,590	(1,474)	(22)%
Southern	921	1,159	(238)	(21)%
Total Appalachia	8,816	9,563	(747)	(8)%
Illinois Basin	3,635	2,907	728	25%
Northern Powder River Basin	735	853	(118)	(14)%
Gulf Coast	290	17	273	1,606%
Total	13,476	13,340	136	1%
Average gross royalty per ton				
Appalachia				
Northern	$ 1.04	$ 1.82	$ (0.78)	(43)%
Central	4.94	5.98	(1.04)	(17)%
Southern	6.05	8.35	(2.30)	(28)%
Total Appalachia	3.83	5.48	(1.65)	(30)%
Illinois Basin	4.23	4.54	(0.31)	(7)%
Northern Powder River Basin	3.10	5.27	(2.17)	(41)%
Gulf Coast	3.24	10.88	(7.64)	(70)%

Combined average gross royalty per ton	$ 3.88	$ 5.27	$ (1.39)	(26)%
Aggregates:				
Royalty revenues	$ 1,996	$ 1,643	$ 353	21%
Aggregate bonus royalty	570		570	100%
Production	1,767	1,239	528	43%
Average base royalty per ton	$ 1.13	$ 1.33	$ (0.20)	(15)%
Oil and Gas:				
Oil and gas revenues	$ 3,886	$ 1,246	$ 2,640	212%
Investment in OCI Wyoming:				
Equity and other unconsolidated investment earnings	$ 7,238	$	$ 7,238	N/A
Cash distributions received	$ 46,006	$	$ 46,006	N/A

Coal Royalty Revenues and Production. Coal royalty revenues comprised approximately 64% and 75% of our total revenues and other income for the three month periods ended September 30, 2013 and 2012, 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 $18.7 million or 36% in the three-month period ended September 30, 2013 compared to the same period of 2012, while production decreased 0.7 million tons or 8%.

As a result of the difficult coal markets, production from our properties in the Central Appalachian region has declined by 22% as some lessees chose to idle mines or mining units during 2012 and in the first nine months of 2013. In addition, pricing realized by the lessees for both steam and metallurgical coal in Central Appalachia is generally below the levels of the same quarter in 2012, causing a higher percentage decrease in coal royalty revenues compared to the decrease in production.

The Southern Appalachian region also had decreased production and coal royalty revenues, primarily due to lower sales of metallurgical coal from the Oak Grove mine, which were also at a lower royalty rate per ton. In addition, production from two lessees moved from our BLC properties to adjacent properties.

With respect to Northern Appalachia, during the quarter ended September 30, 2013 there was a significant increase in production, but a slight decrease in revenues versus the same period in 2012. The increase in tonnage primarily resulted from production from a 1960s era coal lease where the royalty rate per ton is very low. Also contributing to the increased tonnage was a longwall mine moving onto our property during the quarter. However, the longwall mine moving onto our property generates lower royalty per ton than a separate longwall mine that had lower sales during the quarter, which contributed to the decline in revenues.

Illinois Basin. Production and coal royalty revenues for the three months ended September 30, 2013 increased when compared to the same period in 2012. Increased production from the start of the longwall mining unit and the resulting increased sales from our Hillsboro property were offset by lower sales from the Williamson and Macoupin properties.

Northern Powder River Basin. Coal royalty revenues and production decreased on our Western Energy property due to the normal variations that occur due to the checkerboard nature of ownership. The lessee also realized lower sales prices, which reduced the royalty per ton for the quarter.

Aggregate Royalty Revenues and Production. Aggregate revenues increased 21% and production increased 43% for the quarter ended September 30, 2013, compared to the same quarter for 2012, while prices were 15% lower. While aggregate revenues and production were both an increase for the quarter ended September 30, 2013 when compared to the quarter ended September 30, 2012, the increases came from several properties where the royalty rate per ton was significantly lower than the average royalty rate per ton was in third quarter of 2012. In addition to higher royalty revenues and production, in the quarter ended September 30, 2013, we received a royalty bonus on our Washington property of $0.6 million.

Oil and Gas Royalty Revenues. Oil and gas royalty revenues were higher for the current quarter when compared to the same quarter in 2012. A significant increase in royalties received from our Oklahoma assets, as well as revenues from our Bakken/Three Forks properties, resulted in a $2.6 million, or a 212%, increase in revenues over the same quarter for last year. We do not anticipate our Marcellus assets to contribute materially to our revenues until 2014.

Investment in OCI Wyoming. Income from our investment in the OCI Wyoming soda ash business was $7.2 million for the quarter ended September 30, 2013 and we received cash distributions of $46.0 million, which included a one-time special distribution of $44.8 million associated with a refinancing at OCI Wyoming. During the third quarter, OCI Resources LP, which owns 51% of OCI Wyoming, completed an initial public offering. As a result of this offering and OCI Resources obligations to make regular quarterly distributions to its partners, we expect to receive approximately $10.0 million in distributions per quarter in the future. Because our investment in OCI Wyoming occurred at the beginning of 2013 there are no comparable results for the prior year.

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Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
	(Unaudited)			
Coal:				
Royalty revenues				
Appalachia				
Northern	$ 12,008	$ 10,996	$ 1,012	9%
Central	81,861	119,880	(38,019)	(32)%
Southern	20,623	20,694	(71)	
Total Appalachia	114,492	151,570	(37,078)	(24)%
Illinois Basin	40,864	34,886	5,978	17%
Northern Powder River Basin	6,703	6,264	439	7%
Gulf Coast	2,898	333	2,565	770%
Total	$ 164,957	$ 193,053	$ (28,096)	(15)%
Production (tons)				
Appalachia				
Northern	10,051	5,866	4,185	71%
Central	16,062	19,632	(3,570)	(18)%
Southern	3,188	2,547	641	25%
Total Appalachia	29,301	28,045	1,256	4%
Illinois Basin	9,541	7,908	1,633	21%
Northern Powder River Basin	2,499	1,447	1,052	73%
Gulf Coast	862	37	825	2,230%
Total	42,203	37,437	4,766	13%
Average gross royalty per ton				
Appalachia				
Northern	$ 1.19	$ 1.87	$ (0.68)	(36)%
Central	5.10	6.11	(1.01)	(17)%
Southern	6.47	8.12	(1.65)	(20)%
Total Appalachia	3.91	5.40	(1.49)	(28)%
Illinois Basin	4.28	4.41	(0.13)	(3)%
Northern Powder River Basin	2.68	4.33	(1.65)	(38)%
Gulf Coast	3.36	9.00	(5.64)	(63)%
Combined average gross royalty per ton	$ 3.91	$ 5.16	$ (1.25)	(24)%

Aggregates:							
Royalty revenues	$	5,299	$	5,061	$	238	5%
Aggregate royalty bonus		570				570	100%
Production		4,513		4,053		460	11%
Average base royalty per ton	$	1.17	$	1.25	$	(0.08)	(6)%
Oil and Gas:							
Oil and gas revenues	$	9,742	$	6,712	$	3,030	45%
Investment in OCI Wyoming:							
Equity and other unconsolidated investment earnings	$	22,168	$		$	22,168	N/A
Cash distributions received	$	72,946	$		$	72,946	N/A

Coal Royalty Revenues and Production. Coal royalty revenues comprised approximately 63% and 70% of our total revenues and other income for the nine month periods ended September 30, 2013 and 2012, 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 $37.1 million, or 24%, in the nine month period ended September 30, 2013 compared to the same period of 2012, while production increased 1.3 million, or 4%.

As a result of the difficult coal markets, production in the Central Appalachian region declined 18% and coal royalty revenues declined by 32% as some lessees continue to idle mines or mining units. The reduced production by some lessees was partially offset by some mines moving back onto our property during the first nine months of 2013. In addition, pricing realized by the lessees for both steam and metallurgical coal was below the levels of the same period in 2012, causing a higher percentage decrease in coal royalty revenues compared to the decrease in production.

The Southern Appalachian region had increased production but coal royalty revenues were nearly the same, primarily due to the Oak Grove preparation plant operating for the entire nine month period after being idled for much of the first half of 2012 due to damage caused by a tornado in 2011, as well as the lessee having increased sales. In general, our lessees had lower prices, reducing the royalty per ton for the region.

With respect to Northern Appalachia, during the nine months ending September 30, 2013, there was an increase in production and revenues versus the same period in 2012. The primary reason for the increase in tonnage and revenue is that a longwall mine operated on our property for most of the first nine months of 2013 versus only a part of 2012. This increase was partially offset by other lessees reducing production or having lower revenue per ton. We continue to have production on a 1960s era coal lease where the royalty rate per ton is very low.

Illinois Basin. Production and coal royalty revenues for the nine months ended September 30, 2013 increased compared to the same period in 2012. The production increase was primarily due to increased production from the start of the longwall mining unit and the resulting increased sales from our Hillsboro property. In addition, a lessee moved back onto our property during 2013 which had primarily been mining on adjacent property in 2012. These increases were partially offset by lower sales from the Williamson and Macoupin properties.

Northern Powder River Basin. Coal royalty revenues and production increased on our Western Energy property due to the normal variations that occur due to the checkerboard nature of ownership. The lessee did realize lower sales prices, which reduced the royalty per ton for the quarter.

Aggregate Royalty Revenues and Production. Aggregate revenues and production increased slightly in 2013 when compared to the same period in 2012. In addition to our regular production royalties, we received a bonus royalty of $0.6 million in 2013 related to our Washington property.

Oil and Gas Royalty Revenues. Oil and gas royalty revenues were up 45% for the nine months ended September 30, 2013 when compared to the same period in 2012. The increase reflects royalties received from our Oklahoma assets and our Bakken/Three Forks properties, partially offset by decreased revenues from our BRP oil and gas properties in Louisiana. We do not anticipate the Marcellus assets to contribute materially to our revenues until 2014.

Investment in OCI Wyoming. Income from our investment in the OCI Wyoming soda ash business contributed $22.2 million in earnings for the nine months ended September 30, 2013 and we received cash distributions of $72.9 million, which included a special distribution of $44.8 million associated with a refinancing at OCI Wyoming. During the third quarter, OCI Resources LP, which owns 51% of OCI Wyoming, completed an initial public offering. As a result of this offering and OCI Resources   obligations to make regular quarterly distributions to its partners, we expect to receive approximately $10.0 million in distributions per quarter in the future. Because our investment in OCI Wyoming occurred at the beginning of 2013 there are no comparable results for the prior year.

Other Operating Results

In addition to coal, aggregates and oil and gas royalty revenues, we generated approximately 31% and 26% of our revenues and other income from other sources for the first nine months of 2013 and 2012, respectively. Other sources of revenue primarily include: equity income from our investment in OCI Wyoming (with respect to the first nine months of 2013); overriding royalties (which include coal and aggregates overrides); minimums recognized as revenue; and processing and transportation fees. In the first nine months of 2013, we recognized $22.2 million in other income from our equity investment in OCI Wyoming, $11.0 million in overriding royalty revenues and we realized $6.4 million in minimums recognized as revenue. In addition, in the first nine of 2013, we recognized a non-cash gain of $8.1 million resulting from a coal reserve swap on one of our Illinois properties. The revenues that we recognize from minimums and processing/transportation are largely derived from coal-related businesses.

Processing and Transportation Revenues. Processing revenues decreased $0.3 million and $3.0 million for the three and nine months ended September 30, 2013 when compared to the same periods in 2012. The decrease in processing fees was a result of the sale of one of our facilities in the third quarter of 2012, as well as lower Central Appalachian production from the properties that use these facilities to wash their coal.

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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 property in Illinois, we operate handling and transportation infrastructure and have subcontracted out that responsibility to third parties. At the Macoupin and Sugar Camp properties, we own the infrastructure and lease it to Cline affiliates. Transportation fees decreased $0.3 million and $0.9 million for the quarter and nine months ended September 30, 2013 compared to the same periods for 2012. The decrease is attributed to Foresight generating higher production and sales from the Hillsboro property in Illinois rather than from the mines on which we collect a transportation fee. Production decreased on the Williamson and Macoupin properties during the nine months ended September 30, 2013 when compared to the same periods for 2012.

Operating costs and expenses. Included in total expenses are:

Depreciation, depletion and amortization expenses increased $3.4 million and $8.0 million for the three and nine months ended September 30, 2013 when compared to the same periods for 2012. The increase in expense reflects higher oil and gas depletion of approximately $1.0 million per quarter, higher coal depletion due to increases in production during the first nine months of 2013 as well as depletion related to the reserve swap in Illinois when compared to the same period for 2012.

General and administrative expenses decreased $1.0 million for the three months and increased $3.6 for the nine months ended September 30, 2013 compared to the same periods for 2012. The change in general and administrative expense is due to increased compensation and long term incentive expense related to the addition of new employees.

Interest Expense. Interest expense increased approximately $1.8 million and $3.8 million for the three and nine months ended September 30, 2013 over the same periods in 2012. The increase reflects the issuance of a new term loan in January 2013 to fund the OCI acquisition.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

We satisfy our working capital requirements with cash generated from operations. We finance our property acquisitions with available cash, borrowings under our revolving credit facilities, term loans and the issuance of senior notes and additional common 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, oil and gas and aggregate/industrial minerals industries and other factors, some of which are beyond our control. For a more complete discussion of factors that will affect cash flow we generate from operations, see Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012. Our capital expenditures, other than for acquisitions, have historically been minimal.

Our credit ratios are within the debt covenants contained in our subsidiaries credit facilities, term loan and senior notes. For a more complete discussion of factors that will affect our liquidity, see Item 1A. Risk Factors in our Form 10-K for the year ended December 31, 2012. Opco s revolving credit facility does not mature until August 2016 and, as of September 30, 2013, Opco had $300 million in available capacity under the facility. In August 2013, NRP Oil and Gas entered into a senior secured, reserve-based revolving credit facility with an initial $8.0 million borrowing base. As of September 30, 2013, NRP Oil and Gas had the full $8.0 million available for borrowing under its revolving credit facility. In addition to the amounts available under the revolving credit facilities, we had $99.7 million in cash at September 30, 2013. We believe that the combination of our capacity under the revolving credit facilities and our cash on hand gives us enough liquidity to meet our current financial needs. We typically access the capital markets to refinance amounts outstanding under the revolving credit facilities as we approach the limits under those facilities, the timing of which depends on the pace and size of our acquisition program.

We used a portion of the proceeds from the July 2013 distribution from OCI Wyoming to prepay the $10.0 million principal payment that was due in January 2014 on Opco s term loan. In addition, we repaid $91.0 million of principal of Opco s term loan in September 2013 using a portion of the net proceeds from NRP s September 2013 senior notes offering. Following these principal repayments, Opco s next principal repayment obligation on the term loan is not until January 2016, when Opco will be required to repay the remaining principal amount outstanding thereunder of $99.0 million.

In September 2013, NRP, together with NRP Finance as co-issuer, issued $300.0 million of 9.125% senior notes at an offering price of 99.007% of par value. The net proceeds of $289.0 million from the senior notes offering were used to repay all of the outstanding borrowings under Opco s revolving credit facility and $91.0 million of Opco s term loan.

Net cash provided by operations for the nine months ended September 30, 2013 and 2012 was $189.5 million and $193.9 million, respectively. The majority of our cash provided by operations is generated from coal royalty revenues and our equity interest in OCI Wyoming.

Net cash used in investing activities for the nine months ended September 30, 2013 and 2012 was $281.1 million and $176.7 million, respectively. Substantially all of our 2013 investing activities consisted of acquiring investments in OCI Wyoming, see Note 4. Equity and Other Investments. During 2012, the majority of our investing activities consisted of acquiring reserves, plant and equipment and related intangibles as well as assets relating to Sugar Camp.

Net cash flows provided by financing activities for the nine months ended September 30, 2013 was $41.9 million. During the first nine months of 2013, we had net proceeds from loans of $547.0 million, net proceeds from equity transactions of $74.9 million, and a capital contribution from our general partner of $1.5 million. These proceeds were offset by loan repayments of $386.2 million, debt issuance costs of $9.1 million, and distributions to partners of $186.3 million. During the same period for 2012, net cash used in financing activities was $109.7 million, which included proceeds from loans of $103.0 million offset by debt repayments of $30.8 million and $181.3 million for distributions to partners.

Contractual Obligations and Commercial Commitments

NRP Debt

Senior Notes. On September 18, 2013, NRP and NRP Finance as co-issuer completed a private placement of $300,000,000 principal amount of 9.125% Senior Notes due 2018. The notes were offered and sold to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended, and to persons outside the United States pursuant to Regulation S under the Securities Act. The Notes were issued pursuant to an indenture, dated September 18, 2013, among NRP, NRP Finance Corporation and Wells Fargo Bank, National Association, as trustee. The notes bear interest at a rate of 9.125% per year, payable semiannually in arrears on April 1 and October 1 of each year, beginning on April 1, 2014. The notes will mature on October 1, 2018.

The notes are the senior unsecured obligations of NRP and NRP Finance. The notes rank equal in right of payment to all existing and future senior unsecured debt of NRP and NRP Finance and senior in right of payment to any subordinated debt of NRP and NRP Finance. The notes are effectively subordinated in right of payment to all future secured debt of NRP and NRP Finance to the extent of the value of the collateral securing such indebtedness and will be structurally subordinated in right of payment to all existing and future debt and other liabilities of NRP s subsidiaries, including Opco s revolving credit facility and term loan facility, each series of Opco s existing senior notes, and NRP Oil and Gas s revolving credit facility. None of NRP s subsidiaries guarantee the notes.

NRP and NRP Finance have the option to redeem the notes, in whole or in part, at any time on or after April 1, 2016, at the redemption prices (expressed as percentages of principal amount) of 106.844% for the six-month period beginning on April 1, 2016, 104.563% for the twelve-month period beginning on October 1, 2016 and 100.000% beginning on October 1, 2017 and at any time thereafter, together with any accrued and unpaid interest to the date of redemption. In addition, before April 1, 2016, NRP and NRP Finance may redeem all or any part of the notes at a redemption price equal to the sum of the principal amount thereof, plus a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. Furthermore, before April 1, 2016, NRP and

NRP Finance may on any one or more occasions redeem up to 35% of the aggregate principal amount of the notes with the net proceeds of certain public or private equity offerings at a redemption price of 109.125% of the principal amount of notes, plus any accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the aggregate principal amount of the notes issued under the indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. In the event of a change of control, as defined in the indenture, the holders of the notes may require NRP and NRP Finance to purchase their notes at a purchase price equal to 101% of the principal amount of the notes, plus accrued and unpaid interest, if any.

The indenture for the senior notes contains covenants that limit the ability of NRP and certain of its subsidiaries to incur or guarantee additional indebtedness. Under the indenture, NRP and certain of its subsidiaries generally are not permitted to incur additional indebtedness unless, on a consolidated basis, the fixed charge coverage ratio (as defined in the indenture) is at least 2.0 to 1.0 for the four preceding full fiscal quarters. The ability of NRP and certain of its subsidiaries to incur additional indebtedness is further limited in the event the amount of indebtedness of NRP and its subsidiaries that is senior to NRP s unsecured indebtedness exceeds certain thresholds. The indenture contains additional covenants that, among other things, limit NRP s ability and the ability of certain of its subsidiaries to declare or pay any dividend or distribution on, purchase or redeem units or purchase or redeem subordinated debt; make investments; create certain liens; enter into agreements that restrict distributions or other payments from NRP s restricted subsidiaries as defined in the indenture to NRP; sell assets; consolidate, merge or transfer all or substantially all of the assets of NRP and its restricted subsidiaries; engage in transactions with affiliates; create unrestricted subsidiaries; and enter into certain sale and leaseback transactions.

Opco Debt

Senior Notes. Opco 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 Opco s subsidiaries. Opco 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 Opco to:

- Maintain a ratio of consolidated indebtedness to consolidated EBITDDA (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 EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.0.

As of the date of this filing, Opco s debt consisted of:

- $99.0 million floating rate term loan, due January 2016;
- $23.1 million of 4.91% senior notes due 2018;
- $128.6 million of 8.38% senior notes due 2019;
- $53.8 million of 5.05% senior notes due 2020;
- $1.5 million of 5.31% utility local improvement obligation due 2021;

- $27.0 million of 5.55% senior notes due 2023;
- $75.0 million of 4.73% senior notes due 2023;
- $165.0 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.

All of Opco s senior notes require annual principal payments in addition to semi-annual interest payments. The scheduled principal payments on Opco s 8.92% senior notes due in 2024 do not begin until March 2014, and the scheduled principal payments on Opco s 4.73%, 5.03% and 5.18% senior notes do not begin until December 2014. Opco also makes annual principal and interest payments on the utility local improvement obligation.

Revolving Credit Facility. As of the date of this report, Opco had $300 million in available borrowing capacity under its revolving credit facility. Under an accordion feature in the credit facility, Opco may request its lenders to increase their aggregate commitment to a maximum of $500 million on the same terms. However, Opco cannot be certain that its lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, Opco may elect to bring new lenders into the facility, but cannot make any assurance that the additional credit capacity will be available on existing or comparable terms.

During 2013, Opco s borrowings and repayments under its credit facility were as follows:

	Quarter Ending		
	March 31	**June 30**	**September 30**
	(In thousands) **(Unaudited)**		
Outstanding balance, beginning of period	$ 148,000	$ 148,000	$ 191,000
Borrowings under credit facility		43,000	7,000
Less: Repayments under credit facility			(198,000)
Outstanding balance, ending period	$ 148,000	$ 191,000	$

Opco s obligations under the credit facility are unsecured but are guaranteed by its subsidiaries. Opco may prepay all loans at any time without penalty. Indebtedness under Opco s 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%.

Opco incurs 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 Opco credit agreement contains covenants requiring Opco 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.

Term Loan. In connection with the OCI Wyoming acquisition, Opco entered into a 3-year, $200 million term loan facility in January 2013. The term loan facility is guaranteed by Opco s operating subsidiaries and bears interest at a weighted average rate of 2.45%. Interest on the term loan became payable initially in April 2013, with a remaining principal payment of $99.0 million due on January 23, 2016. The term loan facility contains financial covenants and other terms that are identical to those of our credit facility.

NRP Oil and Gas Debt

Revolving Credit Facility. On August 12, 2013, NRP Oil and Gas entered into a 5-year, $100 million senior secured, reserve-based revolving credit facility in order to fund capital expenditure requirements related to the development of the Bakken/Three Forks assets acquired on August 9, 2013. The credit facility has an initial borrowing base of $8.0 million and is secured by a first priority lien and security interest in substantially all of the assets of NRP Oil and Gas. NRP Oil and Gas is the sole obligor under its revolving credit facility, and neither NRP nor any of its other subsidiaries is a guarantor of such facility. As of September 30, 2013, NRP Oil and Gas did not have any borrowings outstanding under the credit facility and had the full $8.0 million available for borrowing thereunder.

Indebtedness under the NRP Oil and Gas credit facility bears interest, at the option of NRP Oil and Gas, at either:

- the higher of (i) the prime rate as announced by the agent bank; (ii) the federal funds rate plus 0.50%; or (iii) LIBOR plus 1%, in each case plus an applicable margin ranging from 0.50% to 1.50%; or a rate equal to LIBOR, plus an applicable margin ranging from 1.75% to 2.75%.

NRP Oil and Gas will incur a commitment fee on the unused portion of the borrowing base under the credit facility at a rate ranging from 0.375% to 0.50% per annum.

The NRP Oil and Gas credit facility contains certain covenants, which, among other things, require the maintenance of (i) a total leverage ratio (defined as the ratio of the total debt of NRP Oil and Gas to its EBITDAX) of not more than 3.5 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The credit facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting the ability of NRP Oil and Gas to, among other items, incur indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of material assets or properties; pay distributions; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; or engage in transactions with affiliates. Events of default under the credit facility include payment defaults, misrepresentations and breaches of covenants by NRP Oil and Gas. The credit facility also contains a cross-default provision with respect to any indebtedness of NRP s, including the notes.

The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in May and November of each year, based on the value of the proved oil and natural gas reserves of NRP Oil and Gas, in accordance with the lenders customary procedures and practices. NRP Oil and Gas and the lenders each have a right to one additional redetermination each year.

Consolidated Debt

The following table reflects our long-term non-cancelable contractual obligations as of September 30, 2013 (in millions):

	Payments Due by Period						
Contractual Obligations	**Total**	**Remaining In 2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**
NRP:							
Long-term debt principal payments (including current maturities)(1)	$ 300.0	$	$	$	$	$	$ 300.0
Long-term debt interest payments(2)	137.9		28.3	27.4	27.4	27.4	27.4
Opco:							
Long-term debt principal payments (including current maturities)(3)	848.0		81.0	81.0	180.0	81.0	425.0
Long-term debt interest payments(4)	239.2	8.8	43.5	38.4	33.3	28.2	87.0
Rental leases(5)	3.6	0.2	0.7	0.7	0.7	0.7	0.6
Total	$ 1,528.7	$ 9.0	$ 153.5	$ 147.5	$ 241.4	$ 137.3	$ 840.0

(1) On September 18, 2013, NRP and NRP Finance issued $300 million of 9.125% senior notes at an offering price of 99.007% of par value due October 1, 2018.

(2) The amounts indicated in the table include interest due on 9.125% senior notes, which accrued from September 18, 2013, the issue date of the senior notes.

(3) The amounts indicated in the table include principal due on Opco s senior notes, as well as the utility local improvement obligation related to our property in DuPont, Washington. On January 24, 2013, Opco entered into a $200 million three year term loan. As of September 30, 2013, there was $99.0 million remaining due in January 2016.

(4) The amounts indicated in the table include interest due on Opco s senior notes as well as the utility local improvement obligation related to our property in DuPont, Washington.

(5) On January 1, 2009, Opco entered into a ten-year lease agreement for the rental of office space from Western Pocahontas Properties Limited Partnership. The rental obligations from this lease are included in the table above.

Shelf Registration Statements

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. On August 15, 2012, we filed a shelf registration statement that registered the resale of all of the units held by Adena Minerals, as well as up to $500 million in equity or debt securities by NRP. Following the effectiveness of this registration statement, Adena distributed 6,049,155 common units to its shareholders, and we subsequently filed a prospectus supplement to register the resale of these units by those shareholders. On April 12, 2013, we filed a resale shelf registration statement to register the 3,784,572 common units issued in the January 2013 private placement. This shelf registration statement was declared effective by the SEC on May 7. 2013. A portion of the common units issued in the private placement were issued, directly and indirectly, to certain of our affiliates, including Corbin J. Robertson, Jr. and Christopher Cline. We cannot control the resale of the common units by any of the selling unitholders under the shelf registration statements, and the amounts, prices and timing of the issuance and sale of any equity or debt securities by NRP will depend on market conditions, our capital requirements and compliance with our credit facility, term loan 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.

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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 $0.7 million at September 30, 2013 for services provided by Quintana. Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands) (Unaudited)			
Reimbursement for services	$ 2,748	$ 2,303	$ 8,481	$ 7,230

For additional information, see Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement in our Annual Report on Form 10-K for the year ended December 31, 2012.

We also lease 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 $0.6 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 4,917,548 common units. Revenues from Cline affiliates are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			

	(Unaudited)			
Coal royalty revenues	$ 14,968	$ 12,894	$ 39,527	$ 34,351
Processing fees	379	715	972	1,745
Transportation fees	4,742	5,008	13,499	14,362
Minimums recognized as revenue			3,477	9,556
Override revenue	957	1,075	2,735	2,768
Other revenue			8,149	
	$ 21,046	$ 19,692	$ 68,359	$ 62,782

At September 30, 2013, we had amounts due from Cline affiliates totaling $61.7 million, of which $56.7 million was attributable to agreements relating to Sugar Camp. As of September 30, 2013, we had received $69.2 million in minimum royalty payments to date that have not been recouped by Cline affiliates, of which $16.3 million was received in the current year.

During 2013, we recognized an $8.1 million non-cash gain on a coal reserve swap in Illinois with Williamson Energy. This gain is reflected in the table above in the Other revenue line. The tons received will be fully mined during 2013, while the tons exchanged are not included in the current mine plans. During the first quarter of 2012, we reported $9.6 million in minimums recognized as revenue attributable to an agreement in 2012 by Gatling Ohio, LLC to relinquish its recoupment rights.

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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.

At September 30, 2013, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp., a coal mining company traded on the TSX Venture Exchange that is one of our lessees in Tennessee. Corbin J. Robertson III, one of our directors, is Chairman of the Board of Corsa. Revenues from Corsa are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands) (Unaudited)			
Coal royalty revenues	$ 1,249	$ 996	$ 3,403	$ 2,594

We also had accounts receivable totaling $0.4 million from Corsa at September 30, 2013.

Environmental

The operations our lessees conduct on our properties are subject to federal and state environmental laws and regulations. See Item 1, Business Regulation and Environmental Matters in our Annual Report on Form 10-K for the year ended December 31, 2012. As an owner of surface interests in some properties, we may be liable for certain environmental conditions occurring on the surface properties. The terms of substantially all of our coal 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. Because we have no employees, employees of Western Pocahontas Properties Limited Partnership 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 have neither incurred, nor are aware of, any material environmental charges imposed on us related to our properties for the period ended September 30, 2013. We are not associated with any environmental contamination that may require remediation costs. However, our lessees do conduct reclamation work on the properties under lease to them. Because we are not the permittee of the mines being reclaimed, we are not responsible for the costs associated with these reclamation operations. In addition, West Virginia has established a fund to satisfy any shortfall in reclamation obligations. During the second quarter of 2013, several citizen group lawsuits were filed against landowners alleging ongoing discharges of pollutants, including selenium, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property has been closed, the property has been reclaimed, and the state reclamation bond has been released. A subsidiary of NRP was named as a defendant in one of these lawsuits, but the suit has been dismissed. While it is too early to determine the merits or predict the outcome of any of these lawsuits, any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations.

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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 and term loan, which are subject to variable interest rates based upon LIBOR. At September 30, 2013, we had $99.0 million in variable interest rate debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $1.0 million, assuming the same principal amount remained outstanding during the year.

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, 2012.

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

2.1	Purchase Agreement, dated as of January 23, 2013, by and among Anadarko Holding Company, Big Island Trona Company, NRP Trona LLC and NRP (Operating) LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on January 25, 2013).
3.1	Certificate of Limited Partnership of Natural Resource Partners L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 filed April 19, 2002, File No. 333-86582)
3.2	Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of September 20, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on September 21, 2010).
3.3	Fifth Amended and Restated Limited Liability Company Agreement of GP Natural Resource Partners LLC dated as of October 31, 2013 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on October 31, 2013).
4.1	Indenture, dated September 18, 2013, by and among Natural Resource Partners L.P. and NRP Finance Corporation, as issuers, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on September 19, 2013).
4.2	Form of 9.125% Senior Notes due 2018 (contained in Exhibit 1 to Exhibit 4.1).
4.3	Registration Rights Agreement, dated September 18, 2013, by and among Natural Resource Partners L.P., NRP Finance Corporation and Citigroup Global Markets Inc., as representative of the several initial purchasers (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 19, 2012).
4.4	First Amendment, dated March 6, 2012, to the Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P. (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q filed on August 7, 2012).
10.1	Credit Agreement, dated as of August 12, 2013, among NRP Oil and Gas LLC, Wells Fargo Bank, N.A., as Administrative Agent, and Wells Fargo Securities, LLC as Sole Bookrunner and Sole Lead Arranger (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 13, 2012).
10.2	Purchase Agreement dated September 13, 2013 by and among Natural Resource Partners L.P., NRP Finance Corporation and Citigroup Global Markets Inc. (as the representative of the several initial purchasers) (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on September 17, 2013).
10.3	Second Amended and Restated Agreement of Limited Partnership of OCI Wyoming, L.P. dated July 18, 2013 (incorporated by reference to Exhibit 10.5 to Amendment No. 1 to Registration Statement on Form S-1 (Registration No. 333-189838) filed by OCI Resources LP on July 22, 2013).
10.4	Third Amended and Restated Agreement of Limited Partnership of OCI Wyoming, L.P. dated September 18, 2013 (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K

	filed by OCI Resources LP on September 18, 2013).
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 September 30, 2013, 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.

* Filed or, in the case of Exhibits 32.1 and 32.2, furnished 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: November 7, 2013

By: /s/ Corbin J. Robertson, Jr.
Corbin J. Robertson, Jr.,
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)

Date: November 7, 2013

By: /s/ Dwight L. Dunlap
Dwight L. Dunlap,
Chief Financial Officer and
Treasurer
(Principal Financial Officer)

Date: November 7, 2013

By: /s/ Kenneth Hudson
Kenneth Hudson
Controller
(Principal Accounting Officer)