NATURAL RESOURCE PARTNERS LP
Form 10-Q
August 08, 2014
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**UNITED STATES**

**SECURITIES AND EXCHANGE COMMISSION**

**Washington, D. C. 20549**

**FORM 10-Q**

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

**For the quarterly period ended June 30, 2014**

**OR**

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

**Commission file number: 001-31465**

**NATURAL RESOURCE PARTNERS L.P.**

**(Exact name of registrant as specified in its charter)**

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

**601 Jefferson Street, Suite 3600**

**Houston, Texas 77002**

**(Address of principal executive offices)**

**(Zip Code)**

**(713) 751-7507**

**(Registrant s telephone number, including area code)**

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

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

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

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

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

At August 8, 2014 there were 111,250,522 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:

- our business strategy;
- our financial strategy;
- prices of and demand for coal, hydrocarbons, aggregates and industrial minerals;
- estimated revenues, expenses and results of operations;
- the amount, nature and timing of capital expenditures;
- our ability to make acquisitions;
- our liquidity and access to capital;
- projected production levels by our lessees;
- OCI Wyoming s trona mining and soda ash refinery operations;
- the impact of governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us and of scheduled or potential regulatory or legal changes; and
- global and U.S. economic conditions.

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, 2013 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 for unit information)**

| | June 30, 2014 (Unaudited) | December 31, 2013 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 70,013 | $ 92,513 |
| Accounts receivable, net of allowance for doubtful accounts | 34,718 | 33,737 |
| Accounts receivable affiliates | 9,018 | 7,666 |
| Other | 1,291 | 1,691 |
| Total current assets | 115,040 | 135,607 |
| Land | 24,340 | 24,340 |
| Plant and equipment, net | 24,035 | 26,435 |
| Mineral rights, net | 1,391,439 | 1,405,455 |
| Intangible assets, net | 59,549 | 66,950 |
| Equity and other unconsolidated investments | 262,661 | 269,338 |
| Loan financing costs, net | 10,357 | 11,502 |
| Long-term contracts receivable affiliates | 50,787 | 51,732 |
| Other assets | 600 | 497 |
| Total assets | $ 1,938,808 | $ 1,991,856 |
| **LIABILITIES AND PARTNERS CAPITAL** | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $ 11,765 | $ 8,659 |
| Accounts payable affiliates | 445 | 391 |
| Current portion of long-term debt | 80,983 | 80,983 |
| Accrued incentive plan expenses current portion | 6,880 | 8,341 |
| Property, franchise and other taxes payable | 6,981 | 7,830 |
| Accrued interest | 15,412 | 17,184 |
| Total current liabilities | 122,466 | 123,388 |
| Deferred revenue | 149,685 | 142,586 |
| Accrued incentive plan expenses | 6,071 | 10,526 |
| Other non-current liabilities | 9,712 | 14,341 |
| Long-term debt | 1,033,041 | 1,084,226 |

| | | |
|---|---|---|
| Partners capital: | | |
| Common units outstanding: (110,869,513 and 109,812,408) | 609,001 | 606,774 |
| General partner s interest | 10,124 | 10,069 |
| Non-controlling interest | (650) | 324 |
| Accumulated other comprehensive loss | (642) | (378) |
| Total partners capital | 617,833 | 616,789 |
| Total liabilities and partners capital | $ 1,938,808 | $ 1,991,856 |

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

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## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

**(In thousands, except per unit data)**

| | Three Months Ended June 30, 2014 | Three Months Ended June 30, 2013 | Six Months Ended June 30, 2014 | Six Months Ended June 30, 2013 |
|---|---|---|---|---|
| | (Unaudited) | | | |
| Revenues and other income: | | | | |
| Coal related revenues | $ 55,361 | $ 67,407 | $ 107,734 | $ 145,250 |
| Aggregate related revenues | 3,563 | 2,899 | 6,959 | 5,855 |
| Oil and gas related revenues | 17,822 | 4,093 | 27,880 | 5,856 |
| Equity and other unconsolidated investment income | 9,401 | 7,882 | 19,180 | 14,930 |
| Property taxes | 3,378 | 3,849 | 7,345 | 7,796 |
| Other | 1,036 | 674 | 1,772 | 1,449 |
| Total revenues and other income | 90,561 | 86,804 | 170,870 | 181,136 |
| Operating expenses: | | | | |
| Depreciation, depletion and amortization | 16,350 | 17,411 | 30,997 | 32,173 |
| Asset impairments | 5,624 | 443 | 5,624 | 734 |
| General and administrative | 9,029 | 8,878 | 14,886 | 20,464 |
| Property, franchise and other taxes | 6,201 | 4,225 | 11,069 | 8,576 |
| Oil and gas lease operating expense | 2,291 | | 4,212 | |
| Transportation costs | 462 | 328 | 884 | 787 |
| Royalty payments | 201 | 187 | 356 | 542 |
| Total operating expenses | 40,158 | 31,472 | 68,028 | 63,276 |
| Income from operations | 50,403 | 55,332 | 102,842 | 117,860 |
| Other income (expense) | | | | |
| Interest expense | (19,037) | (14,440) | (38,897) | (29,103) |
| Interest income | 41 | 173 | 67 | 214 |
| Income before non-controlling interest | 31,407 | 41,065 | 64,012 | 88,971 |
| Non-controlling interest | | | | |
| Net income | $ 31,407 | $ 41,065 | $ 64,012 | $ 88,971 |
| Net income attributable to: | | | | |
| General partner | $ 628 | $ 821 | $ 1,280 | $ 1,779 |
| Limited partners | $ 30,779 | $ 40,244 | $ 62,732 | $ 87,192 |
| Basic and diluted net income per limited partner unit | $ 0.28 | $ 0.37 | $ 0.57 | $ 0.80 |
| Weighted average number of units outstanding | 110,403 | 109,812 | 110,127 | 109,352 |

| | | | | |
|---|---|---|---|---|
| Comprehensive income | $ 31,243 | $ 41,116 | $ 63,748 | $ 89,076 |

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

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**NATURAL RESOURCE PARTNERS L.P.**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

**(In thousands)**

| | Six Months Ended June 30, 2014 | 2013 |
|---|---|---|
| | (Unaudited) | |
| Cash flows from operating activities: | | |
| Net income | $ 64,012 | $ 88,971 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 30,997 | 32,173 |
| Gain on reserve swap | | (8,149) |
| Equity and other unconsolidated investment income | (19,180) | (14,930) |
| Distributions of earnings from unconsolidated investments | 21,935 | 16,162 |
| Non-cash interest charge, net | 1,468 | 555 |
| Gain on sale of assets | | (150) |
| Asset impairment | 5,624 | 734 |
| Change in operating assets and liabilities: | | |
| Accounts receivable | (3,685) | 4,250 |
| Other assets | 318 | (2,985) |
| Accounts payable and accrued liabilities | (413) | 221 |
| Accrued interest | (1,772) | (576) |
| Deferred revenue | 7,099 | 9,951 |
| Accrued incentive plan expenses | (5,916) | (1,219) |
| Property, franchise and other taxes payable | (849) | (1,359) |
| Net cash provided by operating activities | 99,638 | 123,649 |
| Cash flows from investing activities: | | |
| Acquisition of plant and equipment | (135) | |
| Acquisition of mineral rights | (768) | |
| Oil and gas capital expenditures | (8,123) | |
| Acquisition of equity interests | | (292,979) |
| Distributions from unconsolidated affiliates | 3,633 | 10,777 |
| Proceeds from sale of assets | | 154 |
| Return on direct financing lease and contractual override | 600 | 555 |
| Net cash used in investing activities | (4,793) | (281,493) |
| Cash flows from financing activities: | | |
| Proceeds from loans | 2,000 | 243,000 |
| Repayment of loans | (53,483) | (79,538) |
| Deferred financing costs | | (1,621) |

| | | |
|---|---|---|
| Proceeds from issuance of units | 13,842 | 75,000 |
| Capital contribution by general partner | 347 | 1,531 |
| Costs associated with equity transactions | (438) | (60) |
| Distributions to partners | (79,613) | (124,688) |
| Net cash provided by (used in) financing activities | (117,345) | 113,624 |
| Net (decrease) in cash and cash equivalents | (22,500) | (44,220) |
| Cash and cash equivalents at beginning of period | 92,513 | 149,424 |
| Cash and cash equivalents at end of period | $ 70,013 | $ 105,204 |
| Supplemental cash flow information: | | |
| Cash paid during the period for interest | $ 39,135 | $ 29,085 |

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)**

**(Unaudited)**

| | Common Units | | General Partner | Non-Controlling Interest | Accumulated Other Comprehensive Income (Loss) | |
|---|---|---|---|---|---|---|
| | Units | Amounts | Amounts | Amounts | | Total |
| Balance at December 31, 2013 | 109,812,408 | $ 606,774 | $ 10,069 | $ 324 | $ (378) | $ 616,789 |
| Issuance of common units | 1,057,105 | 17,000 | | | | 17,000 |
| Capital contribution | | | 347 | | | 347 |
| Cost associated with equity transactions | | (438) | | | | (438) |
| Distributions | | (77,067) | (1,572) | (974) | | (79,613) |
| Net income | | 62,732 | 1,280 | | | 64,012 |
| Interest rate swap from unconsolidated investments | | | | | (288) | (288) |
| Loss on interest hedge | | | | | 24 | 24 |
| Comprehensive income | | | | | (264) | 63,748 |
| Balance at June 30, 2014 | 110,869,513 | $ 609,001 | $ 10,124 | $ (650) | $ (642) | $ 617,833 |

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

**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 six months ended June 30, 2014 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 2013 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. The Partnership owns a non-controlling equity interest in OCI Wyoming LLC ( OCI Wyoming ), which operates a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming. See Note 4. 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 Consolidated Statements of Comprehensive Income. Amounts relating to prior year s coal royalties, processing fees, transportation fees, minimums recognized as revenue, override royalties and other have been reclassified into a single line item Coal related revenues on this year s Consolidated Statements of Comprehensive Income. Amounts relating to prior year s aggregates royalties, processing fees, minimums recognized as revenue, override royalties and other have been reclassified into a single line item Aggregates related revenues on this year s Consolidated Statements of Comprehensive Income. The following is reclassification reconciliation:

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| | Three Months Ended June 30, 2013 | | | Six Months Ended June 30, 2013 | | |
|---|---|---|---|---|---|---|
| | As Reported | As Reclassified | | As Reported | As Reclassified | |
| | Total | Coal Related Revenues | Aggregate Related Revenues | Total | Coal Related Revenues | Aggregate Related Revenues |
| Revenues: | | | | | | |
| Coal royalties | $ 58,210 | $ 58,210 | $ | $ 112,652 | $ 112,652 | $ |
| Equity and other unconsolidated investment income | 7,882 | | | 14,930 | | |
| Aggregate royalties | 1,751 | | 1,751 | 3,303 | | 3,303 |
| Processing fees | 1,329 | 1,198 | 131 | 2,509 | 2,248 | 261 |
| Transportation fees | 3,832 | 3,832 | | 8,757 | 8,757 | |
| Oil and gas royalties | 4,093 | | | 5,856 | | |
| Property taxes | 3,849 | | | 7,796 | | |
| Minimums recognized as revenue | 836 | 549 | 287 | 5,427 | 5,005 | 422 |
| Override royalties | 3,179 | 2,582 | 597 | 8,084 | 6,444 | 1,640 |
| Other | 1,843 | 1,036 | 133 | 11,822 | 10,144 | 229 |
| Total revenues | $ 86,804 | $ 67,407 | $ 2,899 | $ 181,136 | $ 145,250 | $ 5,855 |

***Recent Accounting Pronouncements***

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**

*Sundance.* On December 19, 2013, the Company completed the acquisition of non-operated working interests in oil and gas properties in the Williston Basin of North Dakota from Sundance Energy, Inc. for $29.4 million, following post-closing purchase price adjustments. The Partnership accounted for the transaction in accordance with the authoritative guidance 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 receipt of the final valuation report from a third-party valuation firm and the subsequent allocation, the assets acquired are included in Oil and gas interests in the accompanying Balance Sheet.

*Abraxas.* On August 9, 2013, the Company completed the acquisition of non-operated working interests in oil and gas properties in the Williston Basin of North Dakota and Montana from Abraxas Petroleum for $38.0 million, following post-closing purchase price adjustments. The Partnership accounted for the transaction in accordance with the authoritative guidance for business combination. During the second quarter of 2014, the Partnership finalized the determination of the fair values of the assets acquired and liabilities assumed in the acquisition, with no material adjustments. The assets acquired are included in mineral rights in the accompanying Consolidated Balance Sheets.

Abraxas and Sundance combined revenues of $21.3 million and lease operating expenses of $4.2 million for the six months ended June 30, 2014 are included in oil and gas related revenues and operating expenses in the Consolidated Statements of Comprehensive Income, respectively.

**4. Equity and Other Investments**

The following summarized results of operations were taken from the OCI Wyoming-prepared unaudited financial statements.

Operating results:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| | (In thousands) | | | |
| Sales | $ 112,970 | $ 110,762 | $ 229,211 | $ 218,992 |
| Gross profit | $ 27,604 | $ 22,372 | $ 54,723 | $ 43,315 |
| Net income | $ 22,145 | $ 18,589 | $ 45,157 | $ 36,958 |
| Income allocation to NRP s equity interests | $ 10,851 | $ 8,565 | $ 22,127 | $ 16,161 |
| Less amortization of basis difference | (1,450) | (683) | (2,947) | (1,231) |
| Equity and other unconsolidated investment income | $ 9,401 | $ 7,882 | $ 19,180 | $ 14,930 |

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For the three and six months ended June 30, 2014, the Partnership derived 10% and 11%, respectively, of its revenues and other income from its equity investment in OCI Wyoming. For the same periods of 2013, the Partnership derived 9% and 8%, respectively, of its revenues and other income from its equity investment in OCI Wyoming.

The terms of the OCI Wyoming acquisition agreement included provisions for the payment of contingent consideration to Anadarko Holding Company if OCI Wyoming achieves certain earnings results in 2013, 2014 or 2015. The Partnership projected that the contingency would be $15 million at December 31, 2013.

The Partnership s contingent consideration consists of the following:

| | June 30, 2014 (In thousands) (Unaudited) |
|---|---|
| Contingent consideration, January 1, 2014 | $ 15,000 |
| Less: consideration paid during the period | (491) |
| Contingent consideration, end of the period | 14,509 |
| Less: current portion of contingent consideration | (4,900) |
| Long-term contingent consideration | $ 9,609 |

The current portion is included in accounts payable and accrued liabilities and the long term portion is included in other non-current liabilities.

In March 2014, Anadarko Holding Company (Anadarko) gave written notice to the Partnership that Anadarko believes the reorganization transactions that occurred at OCI Wyoming in July 2013 triggered an acceleration of the Partnership s obligation to pay the additional contingent consideration in full and demanded immediate payment of such amount. The Partnership does not believe the reorganization transactions triggered an obligation to pay the additional contingent consideration, and the Partnership will continue to engage in discussions with Anadarko to resolve the issue. However, if Anadarko were to prevail on such claim, the Partnership would be required to pay an amount to Anadarko in excess of the $15 million accrual described above up to the net present value of $50 million (the maximum amount of the additional contingent consideration). Any such additional amount would be considered to be additional acquisition consideration and added to Equity and other unconsolidated investments.

**5. Plant and Equipment**

The Partnership s plant and equipment consist of the following:

| | June 30, 2014 | December 31, 2013 |
|---|---|---|
| | (In thousands) | |
| | (Unaudited) | |
| Work in process | $ 135 | $ |

| | | |
|---|---|---|
| Plant and equipment at cost | 55,271 | 55,271 |
| Less accumulated depreciation | (31,371) | (28,836) |
| Net book value | $ 24,035 | $ 26,435 |

| | Six Months Ended June 30, | |
|---|---|---|
| | **2014** | **2013** |
| | **(In thousands) (Unaudited)** | |
| Total depreciation expense on plant and equipment | $ 2,535 | $ 3,133 |

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### 6. Mineral Rights

The Partnership s mineral rights consist of the following:

| | June 30, 2014 | December 31, 2013 |
|---|---|---|
| | (In thousands) | |
| | (Unaudited) | |
| Mineral rights | $ 1,907,589 | $ 1,894,920 |
| Less accumulated depletion and amortization | (516,150) | (489,465) |
| Net book value | $ 1,391,439 | $ 1,405,455 |

| | Six Months Ended June 30, 2014 | 2013 |
|---|---|---|
| | (In thousands) (Unaudited) | |
| Total depletion and amortization expense on mineral rights | $ 26,685 | $ 27,338 |

On April 7, 2014, one of the Partnership s lessees, James River Coal Company, filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As of June 30, 2014, the net book value of the Partnership s properties leased to James River was approximately $35 million, net of previously paid minimums. At this stage in the bankruptcy process, it is unknown whether the Partnership s leases will be accepted or rejected in the bankruptcy process or assigned to a third party in connection with a sale. However, if the Partnership s leases are rejected in the bankruptcy or if mining operations on the Partnership s properties cease, the Partnership may determine that some or all of such properties are impaired. In the first six months of 2014, James River accounted for approximately 1% of total revenues and other income, and for the year ended December 31, 2013, it represented 2% of total revenues and other income. The Partnership does not expect the resolution of the bankruptcy to have a material impact on its revenues and other income. The Partnership will continue to monitor these properties for potential impairment as the bankruptcy proceedings progress.

### 7. Intangible Assets

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

| | June 30, 2014 | December 31, 2013 |
|---|---|---|
| | (In thousands) | |
| | (Unaudited) | |
| Contract intangibles | $ 83,700 | $ 89,421 |

| | | |
|---|---|---|
| Less accumulated amortization | (24,151) | (22,471) |
| Net book value | $ 59,549 | $ 66,950 |

| | Six Months Ended June 30, | |
|---|---|---|
| | 2014 | 2013 |
| | (In thousands) (Unaudited) | |
| Total amortization expense on intangible assets | $ 1,777 | $ 1,702 |

During the second quarter of 2014, the Partnership recognized an impairment expense of $5.6 million relating to an above market contract on an aggregates property. The asset impairment expense is included in Operating costs and expenses on the Consolidated Statements of Comprehensive Income.

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

| | Estimated Amortization Expense (In thousands) (Unaudited) |
|---|---|
| Remainder of 2014 | $ 1,319 |
| For year ended December 31, 2015 | 3,513 |
| For year ended December 31, 2016 | 3,470 |
| For year ended December 31, 2017 | 3,470 |
| For year ended December 31, 2018 | 3,470 |

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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 other 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:

| | June 30, 2014 | December 31, 2013 |
|---|---|---|
| | (In thousands) | |
| | (Unaudited) | |
| 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% | $ 297,468 | $ 297,170 |
| Opco Debt: | | |
| $300 million floating rate revolving credit facility, due August 2016 | 15,000 | 20,000 |
| $200 million floating rate term loan, due January 2016 | 99,000 | 99,000 |
| 4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018 | 18,467 | 23,084 |
| 8.38% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2019 | 107,143 | 128,571 |
| 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 | 53,846 |
| 5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021 | 1,346 | 1,538 |
| 5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023 | 24,300 | 27,000 |
| 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 | 150,000 | 165,000 |

| | | |
|---|---|---|
| 2024 | | |
| 8.92% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2014, maturing in March 2024 | 45,454 | 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 floating rate revolving credit facility due 2018 | 2,000 | |
| Total debt | 1,114,024 | 1,165,209 |
| Less current portion of long term debt | (80,983) | (80,983) |
| Long-term debt | $ 1,033,041 | $ 1,084,226 |

***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. The notes will mature on October 1, 2018.

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The indenture for the senior notes contains covenants that, among other things, limit the ability of 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 $48.3 million on its senior notes during the six months ended June 30, 2014. 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 six months ended June 30, 2014 and year ended December 31, 2013 were 1.97% and 2.23%, 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. At June 30, 2014 Opco had $15 million drawn under the credit facility.

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 2013, Opco issued $200 million in term debt. The weighted average interest rates for the debt outstanding under the term loan for the six months ended June 30, 2014 and the year ended December 31, 2013 were 2.25% and 2.43%, respectively. 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.

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***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 non-operated working interests in oil and gas assets. The credit facility has a borrowing base of $20.0 million as of June 30, 2014 and is secured by a first priority lien and security interest in substantially all of the assets of NRP Oil and Gas. At June 30, 2014, there was $2.0 million outstanding under the credit facility. The weighted average interest rate for the debt outstanding under the credit facility for the six months ended June 30, 2014 was 1.90%.

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) (Unaudited) | | | |
| 2014 | $ | $ 32,500 | $ | $ | $ | $ 32,500 |
| 2015 | | 80,983 | | | | 80,983 |
| 2016 | | 80,983 | 15,000 | 99,000 | | 194,983 |
| 2017 | | 80,983 | | | | 80,983 |
| 2018 | 300,000(1) | 80,983 | | | 2,000 | 382,983 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Thereafter | | 344,124 | | | | 344,124 |
| | $ 300,000 | $ 700,556 | $ 15,000 | $ 99,000 | $ 2,000 | $ 1,116,556 |

(1) The 9.125% senior notes due 2018 were issued at a discount and as of June 30, 2014 were carried at $297.5 million.

NRP LP, Opco and NRP Oil and Gas were in compliance with all terms under their long-term debt as of June 30, 2014.

**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 that includes both current and long-term portions. The Partnership s cash and cash equivalents include money market accounts and are considered a Level 1 measurement. The fair market value and carrying value of the contractual override and long-term senior notes are as follows:

| | Fair Value As Of | | Carrying Value As Of | |
|---|---|---|---|---|
| | June 30, 2014 | December 31, 2013 | June 30, 2014 | December 31, 2013 |
| | (In thousands) | | | |
| | (Unaudited) | | (Unaudited) | |
| Assets | | | | |
| Sugar Camp override, current and long-term | $ 6,622 | $ 6,852 | $ 6,172 | $ 6,063 |
| Liabilities | | | | |
| Long-term debt, current and long-term | $ 999,260 | $ 1,071,880 | $ 998,024 | $ 1,046,209 |

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

**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 $0.4 million at June 30, 2014 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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| | (In thousands) | | | |
| | (Unaudited) | | | |
| Reimbursement for services | $ 2,843 | $ 2,912 | $ 5,781 | $ 5,732 |

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, including Foresight Energy, lease coal reserves from the Partnership, and the Partnership provides coal transportation services to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest (unaudited) in the Partnership s general partner, as well as 4,917,548 common units (unaudited) at June 30, 2014. At June 30, 2014, the Partnership had accounts receivable totaling $8.9 million from Cline affiliates. In addition, the overriding royalty and the lease of the loadout facility at Sugar Camp mine are classified as contracts receivable of $50.8 million on the Partnership s Consolidated Balance Sheets. The Partnership has received $79.6 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $8.6 million was received in the current year.

Coal related revenues from Cline affiliates were $20.4 million and $17.2 million and $38.3 million and $47.3 million, for the three and six months ended June 30, 2014 and 2013, respectively. For the six months ending June 30, 2013, the results included $8.1 million from a reserve swap and $3.5 million from minimums that expired on Foresight Energy s Macoupin mine and were recognized as revenue.

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The Partnership entered into a lease agreement related to the rail loadout and associated facilities at Sugar Camp that has been accounted for as a direct financing lease. Total projected remaining payments under the lease at June 30, 2014 are $88.8 million with unearned income of $40.9 million. The net amount receivable under the lease as of June 30, 2014 was $47.9 million, of which $1.8 million is included in Accounts receivable affiliates while the remaining is included in Long-term contracts receivable affiliates.

In a separate transaction, the Partnership acquired a contractual overriding royalty interest from a Cline affiliate that will provide for payments based upon production from specific tons at the Sugar Camp operations. This overriding royalty was accounted for as a financing arrangement and is reflected as an affiliate receivable. The net amount receivable under the agreement as of June 30, 2014 was $6.2 million, of which $1.5 million is included in Accounts receivable affiliates while the remaining is included in Long-term contracts receivable affiliate.

***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 June 30, 2014, 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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| | (In thousands) | | | |
| | (Unaudited) | | | |
| Coal royalty revenues | $ 657 | $ 1,051 | $ 1,563 | $ 2,154 |

The Partnership also had accounts receivable totaling $0.1 million from Corsa at June 30, 2014.

A fund controlled by Quintana Capital owned a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart s 5-person board of directors. Subsequent to the end of the second quarter of 2013, Taggart was sold to Forge Group, and Quintana no longer retains an interest in Taggart or Forge. The Partnership owns and leases preparation plants to Forge, which operates the plants. The lease payments were based on the sales price for the coal that was processed through the facilities.

Revenues from Forge for the six months ended June 30, 2013 were $1.8 million. Subsequent to the end of the second quarter of 2013, Taggart/Forge is no longer considered a related party of the Partnership.

**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 June 30, 2014. The Partnership is not associated with any environmental contamination that may require remediation costs.

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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 June 30, | | | | Six Months Ended June 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2014 | | 2013 | |
| | (Dollars in thousands) (Unaudited) | | | | | | | |
| | Revenues | Percent | Revenues | Percent | Revenues | Percent | Revenues | Percent |
| The Cline Group | $ 20,432 | 23% | $ 17,184 | 20% | $ 38,254 | 22% | $ 47,313 | 26% |
| Alpha Natural Resources | $ 12,810 | 14% | $ 15,125 | 17% | $ 24,451 | 14% | $ 28,907 | 16% |

In the first six months of 2014, the Partnership derived over 36% of its total revenues and other income from the two companies listed above. 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 10% and 11%, respectively, of the Partnership s total revenues and other income for the first three and six months of 2014.

**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 2014 is as follows:

| | (Unaudited) |
|---|---|
| Outstanding grants at January 1, 2014 | 1,012,984 |

| | |
|---|---|
| Grants during the year | 305,099 |
| Grants vested and paid during the year | (221,700) |
| Forfeitures during the year | (27,460) |
| Outstanding grants at June 30, 2014 | 1,068,923 |

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 0.13% to 1.28% and 30.42% to 33.33%, respectively at June 30, 2014. The Partnership s average distribution rate of 7.34% and historical forfeiture rate of 5.22% were used in the calculation at June 30, 2014. The Partnership recorded expenses related to its plan to be reimbursed to its general partner of $1.5 million and $1.9 million for the three months ended June 30, 2014 and 2013, respectively, and for the six months ended June 30, 2014 and 2013 the Partnership recorded expense of $0.4 million and $7.0 million, respectively. In connection with the Long-Term Incentive Plan, payments are typically made during the first quarter of the year. Payments of $5.3 million and $7.0 million were made during the six month period ended June 30, 2014 and 2013, respectively.

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

The unaccrued cost, associated with the unvested outstanding grants and related DERs at June 30, 2014 was $9.4 million.

**14. Shelf Registration Statements and At-the-Market Program**

On April 24, 2012, the Partnership 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 the Partnership s previous shelf registration statement, which expired at the end of February 2012.

On August 15, 2012, the Partnership filed a shelf registration statement on Form S-3 that registered all of the common units held by Adena Minerals. This shelf registration statement was declared effective by the SEC on September 21, 2012. Following the effectiveness of this registration statement, Adena distributed 15,181,716 common units to its shareholders, and the Partnership subsequently filed prospectus supplements to register the resale of these common units by those shareholders. The shelf registration statement filed in August 2012 also registered up to $500 million in equity securities that may be issued by the Partnership. On November 12, 2013, the Partnership filed a prospectus supplement and entered into an Equity Distribution Agreement relating to the offer and sale from time to time of common units having an aggregate offering price of $75 million through one or more managers acting as sales agents at prices to be agreed upon at the time of sale. Under the terms of the Equity Distribution Agreement, the Partnership may also sell common units from time to time to any manager as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to any manager as principal would be pursuant to the terms of a separate terms agreement between the Partnership and such manager. Sales of common units in this at-the-market ( ATM ) program are made pursuant to the shelf registration statement declared effective in September 2012. For the six months ended June 30, 2014 the Partnership sold 1,057,105 common units for an average price of $16.08 for gross proceeds of $17.0 million, including proceeds relating to 185,097 common units that initially traded on or prior to June 30, 2014 but that were settled subsequent to June 30, 2014. At June 30, 2014, the Partnership had received $14.0 million of the proceeds and recorded an accounts receivable for the balance of $3.0 million relating to the common units that settled subsequent to June 30, 2014. In addition, the Partnership has agreed to pay the ATM program manager a fee of up to 2% of the gross proceeds from the sale of common units under the ATM program and had accrued $0.1 million in such fees payable to the manager of the ATM program as of June 30, 2014.

On April 12, 2013, the Partnership filed a resale shelf registration statement on Form S-3 to register the 3,784,572 common units issued in the January 2013 private placement related to funding of the OCI Wyoming acquisition. This shelf registration statement was declared effective by the SEC in May 2013. A portion of the common units issued in the private placement were issued, directly and indirectly, to certain of the Partnership s affiliates, including Corbin J. Robertson, Jr. and Christopher Cline.

**15. Distributions**

On May 14, 2014, the Partnership paid a quarterly distribution $0.35 per unit to all holders of common units on May 5, 2014.

**16. Subsequent Events**

The following represents material events that have occurred subsequent to June 30, 2014 through the time of the Partnership s filing of this Quarterly Report on Form 10-Q with the Securities and Exchange Commission:

***Distributions***

On July 22, 2014, the Partnership declared a distribution of $0.35 per unit to be paid on August 14, 2014 to holders of common units on August 5, 2014.

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***Distributions Received From Unconsolidated Equity and Other Investments***

Subsequent to June 30, 2014, the Partnership received $10.3 million in cash distributions from its equity investment in OCI Wyoming.

***ATM Program***

As of the date of this filing, the Partnership has issued an additional 381,009 units at an average price of $16.33 for gross proceeds of $6.2 million through its ATM program.

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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, 2013, as filed on February 28, 2014.*

*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 a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, oil and gas, construction aggregates, frac sand and other natural resources. For the six months ended June 30, 2014, we recognized approximately $107.7 million (63%) of our revenues and other income from coal-related sources, and $63.1 million (37%) of our revenues and other income from non-coal-related sources.

Our coal reserves are located 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, 2013, we owned or controlled approximately 2.3 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, particularly in the Illinois Basin. In addition, we own various interests in oil and gas properties that are located in the Williston Basin, the Appalachian Basin, Louisiana and Oklahoma, and we own approximately 500 million tons of aggregate reserves located in a number of states across the country.

We own a 49% interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. OCI Resources LP, our operating partner, mines the trona, processes it into soda ash, and distributes the soda ash both domestically and internationally into the glass and chemicals industries. We receive regular quarterly distributions from this business, and record the income in accordance with our 49% equity interest in the company.

In our coal and aggregates 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.

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 incur capital expenditures and operating expenses associated with the non-operated working interests in oil and gas assets. 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.

***Our Current Liquidity Position***

As of June 30, 2014, Opco had $285.0 million in available borrowing capacity under its revolving credit facility. As of such date, NRP Oil and Gas had $18.0 million in available borrowing capacity under its revolving credit facility. 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.

In addition to the amounts available under our revolving credit facilities, we had $70.0 million in cash as of June 30, 2014. As of the date of this report, we have sold 1,438,114 common units through our at-the-market offering ( ATM ) program for approximately $23.2 million in gross proceeds, excluding our general partner s capital contribution to maintain its 2% general partner interest in us. During the first half of 2014, we repaid $48.3 million of principal on Opco s senior notes and repaid $5.0 million under Opco s revolving credit facility, thereby reducing our total outstanding debt by $53.3 million. Because we used cash to repay principal on Opco s notes during the first half of 2014, our current liabilities exceeded our current assets by approximately $7.4 million as of June 30, 2014.

We believe that the combination of our borrowing capacity under our revolving credit facilities and our cash on hand gives us enough liquidity to meet our current financial needs. Other than $81 million in principal repayments due on Opco s senior notes each year for the next several years (including $32.5 million of principal payments remaining in 2014), we do not have any debt maturing until 2016. While we intend to reduce our leverage by repaying such amounts with cash from operations and issuances of equity through our ATM program, we may refinance such amounts as they come due.

***Current Results/Market Outlook***

Our total revenues and other income for the six months ended June 30, 2014 were $170.9 million, which were down compared to $181.1 million in total revenues and other income earned for the six months ended June 30, 2013. Although our total revenues and other income were down only 6% from the first half of 2013, our coal related revenues were down approximately 26% compared to the same period. The majority of the decrease in coal-related revenues was due to lower Central Appalachian coal royalty revenues, which were down 23% from the first half of 2013. We continue to see the benefits of our diversification efforts, as our revenues and other income from sources other than coal represented 37% of our total revenues and other income in the first half of 2014, up from approximately 20% of total revenues and other income in the first half of 2013. During the first half of 2014, our investment in OCI Wyoming s trona mining and soda ash production operations contributed $19.2 million in other income, and our oil and gas revenues increased to $27.9 million, up $22.0 million as compared to the first half of 2013.

The challenges that have affected the coal markets over the last two years have continued into the first half of 2014. While the thermal coal market was starting to show signs of recovery earlier this year aided by the cold winter and higher natural gas prices, the cooler than anticipated summer so far has put downward pressure on natural gas prices and dampened some of the optimism around thermal coal prices. In addition, rail transportation service issues continue to affect thermal coal prices. We believe that thermal coal production from our properties in the low-cost Illinois Basin will continue to remain strong in spite of the weak thermal markets, and in the second quarter of 2014, we completed an acquisition of additional thermal coal reserves in the Illinois Basin for $5.0 million from a private seller. We expect the markets for thermal coal from our other regions to remain weak for the remainder of 2014.

We continue to have substantial exposure to metallurgical coal, from which we derived approximately 41% of our coal revenues and 32% of the related production during the first six months of 2014. The third quarter 2014 benchmark price for metallurgical coal remains at a multi-year low of $120 per metric ton. The global metallurgical coal market continues to suffer from oversupply in addition to reduced demand from China. In June 2014, Cliffs Natural Resources issued a WARN notice and announced that it intended to idle the Pinnacle Mine in West Virginia, where we own substantial metallurgical coal reserves. Although Cliffs announced in August 2014 that it does not intend to idle the mine, if the mine were to be idled for an extended period, it would materially reduce our metallurgical coal revenues. We have exposure to three mines included in a WARN notice issued by Alpha Natural Resources in West Virginia in July, but even if those mines are ultimately idled, we do not expect there to be a material adverse impact on our 2014 results, as the mines are projected to continue full operations through the third quarter. We do not anticipate metallurgical coal prices recovering in 2014, and additional reductions of production of metallurgical coal from our properties may occur in the remainder of 2014 as long as prices remain at current levels.

Our trona mining and soda ash refinery business performed in line with our expectations during the first six months of 2014. The international market for soda ash continues to improve, as global production capacity for high-cost synthetic soda ash continues to be reduced, and OCI Wyoming s sales through ANSAC were better than expected. The strong international sales were partially offset by lower than expected domestic sales volumes, which are typically sold at a higher price. The cash we receive from OCI Wyoming is in part determined by the quarterly distribution declared by OCI Resources LP. Subsequent to the end of the second quarter, OCI Resources LP announced that it would maintain its quarterly distribution at $0.50 per common unit.

The natural gas and crude oil markets in the second quarter have continued to be robust. Natural gas prices displayed relative stability despite moderately cool weather and large builds in storage. Oil markets have continued a strong growth trajectory into the second quarter due to healthy prices and production growth from new wells coming on line in the primary oil producing plays such as the Bakken/Three Forks. We anticipate our oil and natural gas assets will see continued development and production growth during 2014 as long as the commodities markets remain strong.

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### *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. In addition, the electric utility industry, which is the most significant end-user of domestic coal, is subject to extensive regulation regarding the environmental impact of its power generation activities. In January 2014, EPA published proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. In June 2014, EPA issued proposed regulations on existing fossil fuel-fired power plants (the Clean Power Plan), calling for a nationwide reduction in $CO_2$ emissions of 30% below 2005 levels by 2030. While the timing of implementation of these proposed rules is uncertain, we expect that EPA s proposed regulations for new power plants and the Clean Power Plan will negatively affect the viability of coal-fired power generation, which will ultimately reduce coal consumption and the production of coal from our properties. Furthermore, EPA s Mercury and Air Toxics (MATS) rule and Cross-State Air Pollution Rule (CSAPR), which have been recently upheld by U.S. federal courts, are expected to adversely affect coal-fired power plants in the nearer term. Additional recent decisions by U.S. federal courts granting EPA the power to challenge and under certain circumstances retroactively veto permits further prolongs uncertainties for companies operating with Clean Water Act fill permits and their business partners.

In addition to government action, private citizens groups have continued to be active in bringing lawsuits against operators and landowners. In 2012 and 2013, several citizen group lawsuits were filed against mine operators for allegedly violating conditions in their NPDES permits requiring compliance with West Virginia s water quality standards. Some of the lawsuits allege violations of water quality standards for selenium, whereas others allege that discharges of conductivity and sulfate are causing violations of West Virginia s narrative water quality standards, which generally prohibit adverse effects to aquatic life. The citizen suit groups seek penalties as well as injunctive relief that would limit future discharges of selenium, conductivity or sulfate. While it is too early to determine the ultimate resolution of these lawsuits, any rulings requiring operators to reduce their discharges of selenium, conductivity or sulfate could result in large treatment expenses for our lessees. In 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. While it is too early to predict the final outcome of any of these lawsuits, any final 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.

### *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 December 2013, we acquired 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 $29.4 million, following post-closing purchase price adjustments. The properties, which are all held by production are located in McKenzie, Mountrail and Dunn counties and are actively being developed.

*Abraxas*. In August 2013, we acquired non-operated working interests in producing oil and gas properties in the Williston Basin of North Dakota and Montana, including properties producing from the Bakken/Three Forks play, from Abraxas Petroleum Corporation for $38.0 million, following post-closing purchase price adjustments.

*OCI Wyoming.* In January 2013, we acquired a non-controlling equity interest in OCI Wyoming, an operator of a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming, from Anadarko Holding Company and its subsidiary, Big Island Trona Company for $292.5 million. The acquisition agreement provides for up to the net present value of $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. We accrued $15 million as part of the purchase consideration, of which we have paid $0.5 million in contingent consideration to Anadarko with respect to 2013.

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***Non-GAAP Financial Measures***

***Distributable Cash Flow***

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

Our distributable cash flow represents cash flow from operations, proceeds from sale of assets, returns on direct financing lease and contractual override and distributions from unconsolidated affiliates. 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.

**Reconciliation of Net cash provided by operating activities to Distributable cash flow**

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| | (in thousands) (unaudited) | | | |
| Net cash provided by operating activities | $ 61,008 | $ 79,736 | $ 99,638 | $ 123,649 |
| Return on direct financing lease and contractual override | 303 | 137 | 600 | 555 |
| Distributions from unconsolidated affiliates | 3,633 | 10,777 | 3,633 | 10,777 |
| Proceeds from sale of assets | | | | 154 |
| Distributable cash flow | $ 64,944 | $ 90,650 | $ 103,871 | $ 135,135 |

***EBITDA***

EBITDA is a non-GAAP financial measure that we define as earnings before interest, taxes, depreciation, depletion and amortization and asset impairment. EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. EBITDA should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. EBITDA provides no information regarding a company s capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax positions. EBITDA does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital and other commitments and obligations. Our management team believes EBITDA is useful in evaluating our financial performance because this measure is widely used by analysts and investors for comparative purposes.

EBITDA is a financial measure widely used by investors in the high-yield bond market. There are significant limitations to using EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating EBITDA reported by different companies.

**Reconciliation of Net income to EBITDA**

| | Three Months Ended June 30, | | Six Month Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| | (in thousands) (unaudited) | | | |
| Net income | $ 31,407 | $ 41,065 | $ 64,012 | $ 88,971 |
| Add depreciation, depletion and amortization | 16,350 | 17,411 | 30,997 | 32,173 |
| Add asset impairments | 5,624 | 443 | 5,624 | 734 |
| Add interest expense, gross | 19,037 | 14,440 | 38,897 | 29,103 |
| Add depreciation, depletion and amortization relating to OCI Wyoming | 4,760 | 2,709 | 9,368 | 5,701 |
| EBITDA | $ 77,178 | $ 76,068 | $ 148,898 | $ 156,682 |

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EBITDA presented in the table above differs from the EBITDDA definitions contained in Opco s debt agreement covenants. In calculating EBITDDA for purposes of Opco s debt covenant compliance, pro forma effect may be given to acquisitions and dispositions made during the relevant period. See Liquidity and Capital Resources Contractual Obligations and Commercial Commitments Opco Debt for a description of Opco s debt agreements.

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**Results of Operations**

As disclosed in Note 2: Significant Accounting Policies Update, amounts relating to coal royalties, processing fees, transportation fees, minimums recognized as revenue, override royalties and other for the three and six months ended June 30, 2013 have been reclassified into a single line item Coal related revenues on the Consolidated Statements of Comprehensive Income for the three and six months ended June 30, 2014. Similarly, amounts relating to 2013 aggregate royalties, processing fees, minimums recognized as revenue, override royalties and other have been reclassified into a single line item Aggregate related revenues on the 2014 Consolidated Statements of Comprehensive Income. Accordingly, we have revised our comparative discussions below to make corresponding changes.

***Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013***

***Coal Related Revenues***

| | Three Months Ended June 30, 2014 | Three Months Ended June 30, 2013 | Increase (Decrease) | Percentage Change |
|---|---|---|---|---|
| | (In thousands, except percent and per ton data) | | | |
| | (Unaudited) | | | |
| Regional Statistics | | | | |
| *Coal royalty production (tons)* | | | | |
| Appalachia | | | | |
| Northern | 1,826 | 3,531 | (1,705) | (48)% |
| Central | 5,288 | 5,826 | (538) | (9)% |
| Southern | 949 | 1,163 | (214) | (18)% |
| Total Appalachia | 8,063 | 10,520 | (2,457) | (23)% |
| Illinois Basin | 3,416 | 3,012 | 404 | 13% |
| Northern Powder River Basin | 173 | 969 | (796) | (82)% |
| Gulf Coast | 199 | 393 | (194) | (49)% |
| Total | 11,851 | 14,894 | (3,043) | (20)% |
| *Average coal royalty revenue per ton* | | | | |
| Appalachia | | | | |
| Northern | $ 1.07 | $ 1.20 | $ (0.13) | (11)% |
| Central | 4.50 | 5.18 | (0.68) | (13)% |
| Southern | 5.14 | 6.32 | (1.18) | (19)% |
| Total Appalachia | 3.80 | 3.97 | (0.17) | (4)% |
| Illinois Basin | 4.12 | 4.26 | (0.14) | (3)% |
| Northern Powder River Basin | 2.09 | 2.37 | (0.28) | (12)% |
| Gulf Coast | 3.54 | 3.29 | 0.25 | 8% |
| Combined average gross royalty per ton | $ 3.86 | $ 3.91 | $ (0.05) | (1)% |
| *Coal royalty revenues* | | | | |

| | | | | |
|---|---|---|---|---|
| Appalachia | | | | |
| Northern | $ 1,958 | $ 4,242 | $ (2,284) | (54)% |
| Central | 23,781 | 30,185 | (6,404) | (21)% |
| Southern | 4,875 | 7,352 | (2,477) | (34)% |
| Total Appalachia | 30,614 | 41,779 | (11,165) | (27)% |
| Illinois Basin | 14,083 | 12,843 | 1,240 | 10% |
| Northern Powder River Basin | 362 | 2,295 | (1,933) | (84)% |
| Gulf Coast | 704 | 1,293 | (589) | (46)% |
| Total | $ 45,763 | $ 58,210 | $ (12,447) | (21)% |
| *Other coal related revenues* | | | | |
| Override revenue | $ 1,402 | $ 2,582 | $ (1,180) | (46)% |
| Transportation and processing fees | 5,996 | 5,030 | 966 | 19% |
| Minimums recognized as revenue | 1,338 | 549 | 789 | 144% |
| Wheelage | 862 | 1,036 | (174) | (17)% |
| Total | $ 9,598 | $ 9,197 | $ 401 | 4% |
| Total coal related revenues | $ 55,361 | $ 67,407 | $ (12,046) | (18)% |

*Total coal related revenues.* Total coal related revenues comprised approximately 61% and 78% of our total revenues and other income for the three month periods ended June 30, 2014 and 2013, respectively. The following is a discussion of the major categories of coal related revenue:

*Coal royalty revenues and production*. Coal royalty revenues comprised approximately 51% and 67% of our total revenues and other income for the three month periods ended June 30, 2014 and 2013, 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 $11.2 million or 27% in the three-month period ended June 30, 2014 compared to the same period of 2013, while production decreased 2.5 million tons or 23%.

Production from our properties in the Central Appalachian region declined by 9% due to a combination of the idling of mining units or mines, lower sales volumes from mines on our property and some mining units moving to adjacent properties in the normal course of mining. In addition, pricing realized by our lessees for both thermal and metallurgical coal in Central Appalachia is generally below the levels received in the same quarter in 2013, 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 one of our lessees having lower production during the transition period after the acquisition of the operations of a previous lessee and another lessee having lower sales than the same period in 2013. In addition prices from the metallurgical sales from our properties were lower than the same period in 2013, creating a higher percentage decrease in coal royalty revenue compared to the decrease in coal production.

With respect to Northern Appalachia, during the quarter ended June 30, 2014 there was also a decrease in coal royalty revenue and production. These decreases were primarily due to the longwall mining unit of one lessee moving off of our property to adjacent property in the normal course of its mining plan.

*Illinois Basin*. Coal royalty revenues for the three months ended June 30, 2014 increased 10% when compared to the same period in 2013, and production increased by 13%. Increased production from our Williamson, Hillsboro and Macoupin properties was partially offset by lower sales from another property in Indiana where a lessee had a greater proportion of production from adjacent properties. Prices received by our lessees were at or below those received in the same period in 2013, causing a decrease in the revenue per ton for the region.

*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 reported a lower sales price for the three months ending June 30, 2014, reducing the royalty revenue per ton.

*Gulf Coast*. Coal royalty revenue and production for the three months ended June 30, 2014 decreased compared to the same period in 2013 due to lower production by our lessees.

*Other coal related revenues*. Other coal related revenues for the three months ended June 30, 2014 increased 4% compared to the same period in 2013. The following is a discussion of the revenues derived from each of the major sources of other coal-related revenue:

Override revenues for the three months ended June 30, 2014 decreased by 46% compared to the same period in 2013 primarily due to one lessee moving its mining operations from an area on which we receive an overriding royalty onto property on which we receive coal royalty revenues and another lessee mining less on the area subject to our overriding royalty.

Transportation and processing fees increased by $1.0 million or 19%, for the three months ended June 30, 2014, when compared to the same period in 2013. The increase is primarily due to higher tonnage being put through our Williamson facility, which was partially offset by the temporary idling of two processing facilities in response to market conditions and timing of tonnage moving across our transportation assets.

Minimums recognized as revenue increased $0.8 million or 144% for the three months ended June 30, 2014 when compared to the same period in 2013, primarily due to the recoupment period on one of our lessee s previously paid annual minimums expiring and adjustment to the recoupable balance of another lessee.

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Wheelage revenue decreased by 17% for the three months ended June 30, 2014 compared to the same period in 2013. This decrease was due to the normal fluctuations of tonnage that are subject to wheelage charges.

***Aggregates and Industrial Minerals Revenues, and Other Related Income***

| | Three Months Ended June 30, 2014 | 2013 | Increase (Decrease) | Percentage Change |
|---|---|---|---|---|
| | (In thousands, except percent and per ton data) | | | |
| | (Unaudited) | | | |
| *Aggregates royalty revenues and production* | | | | |
| Tonnage | 927 | 1,463 | (536) | (37)% |
| Aggregates royalty per ton | $ 0.69 | $ 1.20 | $ (0.51) | (43)% |
| Total aggregates royalty revenues | $ 644 | $ 1,751 | $ (1,107) | (63)% |
| Other aggregates related revenues | $ 2,919 | $ 1,148 | $ 1,771 | 154% |
| Total aggregates related revenues | $ 3,563 | $ 2,899 | $ 664 | 23% |
| Equity and other unconsolidated investment earnings | $ 9,401 | $ 7,882 | $ 1,519 | 19% |
| Total aggregates and industrial minerals revenues, and other related income | $ 12,964 | $ 10,781 | $ 2,183 | 20% |

*Total aggregates and industrial minerals revenues, and other related income.* Total aggregates and industrial minerals revenues, and other related income represented approximately 14% and 12% of our total revenues and other income for the three month periods ended June 30, 2014 and 2013, respectively. The following is a discussion of the major categories of these revenues:

Aggregates royalty revenues decreased 63% and production decreased 37% for the quarter ended June 30, 2014 and while average royalty per ton decreased 43%. This decrease is primarily due to one of our lessees moving from property we own to property on which we receive an override.

Other aggregates related revenues were up $1.8 million or 154% compared to last year due to a lessee relinquishing their recoupments rights in 2014 on previously paid minimums and override revenues increasing on our Washington aggregates property due to a lessee moving from our owned property to an area subject to an override. Override revenues also increased on our frac sand properties by $0.4 million or 60% over the second quarter of 2013.

*Equity and other unconsolidated investment earnings*. Income from our investment in the OCI Wyoming trona mining and soda ash production business was $9.4 million for the quarter ended June 30, 2014 and we received $13.9 million in cash during the quarter. For the same period in 2013, we recorded equity income of $7.9 million and received $26.7 million in cash. This represents an increase in equity income of 19% due to improved earnings from OCI Wyoming in 2014 over 2013.

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***Oil and Gas Revenues***

| | Three Months Ended June 30, 2014 | 2013 | Increase (Decrease) | Percentage Change |
|---|---|---|---|---|
| | (In thousands, except percent and per unit data) | | | |
| | (Unaudited) | | | |
| *Williston Basin non-operated working interests:* | | | | |
| *Production volumes* | | | | |
| Oil (MBbl) | 139 | N/A | N/A | N/A |
| Natural gas (Mcf) | 97 | N/A | N/A | N/A |
| NGL (MBoe) | 10 | N/A | N/A | N/A |
| *Average sales price per unit* | | | | |
| Oil (Bbl) | $ 93.40 | N/A | N/A | N/A |
| Natural gas (Mcf) | $ 5.71 | N/A | N/A | N/A |
| NGL (Boe) | $ 35.40 | N/A | N/A | N/A |
| *Revenues* | | | | |
| Oil | $ 12,982 | N/A | N/A | N/A |
| Natural gas | 554 | N/A | N/A | N/A |
| NGL | 354 | N/A | N/A | N/A |
| Total | $ 13,890 | N/A | N/A | N/A |
| *Other oil and gas revenues* | | | | |
| Royalty and overriding revenues | $ 3,932 | 4,093 | $ (161) | (4)% |
| Total oil and gas revenues | $ 17,822 | $ 4,093 | $ 13,729 | 335% |

Oil and gas revenues increased $13.7 million for the current quarter when compared to the same quarter in 2013. The increase in revenues is due to revenues from our Williston Basin non-operated working interest properties which were acquired during the second half of 2013.

***Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013***

***Coal Related Revenues***

| | Six Months Ended June 30, 2014 | Six Months Ended June 30, 2013 | Increase (Decrease) | Percentage Change |
|---|---|---|---|---|
| | (In thousands, except percent and per ton data) | | | |
| | (Unaudited) | | | |
| Regional Statistics | | | | |
| *Coal royalty production (tons)* | | | | |
| Appalachia | | | | |
| Northern | 4,477 | 7,272 | (2,795) | (38)% |
| Central | 9,664 | 10,946 | (1,282) | (12)% |
| Southern | 1,933 | 2,267 | (334) | (15)% |
| Total Appalachia | 16,074 | 20,485 | (4,411) | (22)% |
| Illinois Basin | 6,538 | 5,906 | 632 | 11% |
| Northern Powder River Basin | 1,052 | 1,764 | (712) | (40)% |
| Gulf Coast | 439 | 572 | (133) | (23)% |
| Total | 24,103 | 28,727 | (4,624) | (16)% |
| *Average coal royalty revenue per ton* | | | | |
| Appalachia | | | | |
| Northern | $ 0.91 | $ 1.25 | $ (0.34) | (27)% |
| Central | 4.53 | 5.17 | (0.64) | (12)% |
| Southern | 5.35 | 6.64 | (1.29) | (19)% |
| Total Appalachia | 3.62 | 3.94 | (0.32) | (8)% |
| Illinois Basin | 4.06 | 4.32 | (0.26) | (6)% |
| Northern Powder River Basin | 2.83 | 2.51 | 0.32 | 13% |
| Gulf Coast | 3.46 | 3.42 | 0.04 | 1% |
| Combined average gross royalty per ton | $ 3.70 | $ 3.92 | $ (0.22) | (6)% |
| *Coal royalty revenues* | | | | |
| Appalachia | | | | |
| Northern | $ 4,096 | $ 9,126 | $ (5,030) | (55)% |
| Central | 43,818 | 56,591 | (12,773) | (23)% |
| Southern | 10,339 | 15,052 | (4,713) | (31)% |
| Total Appalachia | 58,253 | 80,769 | (22,516) | (28)% |
| Illinois Basin | 26,553 | 25,500 | 1,053 | 4% |
| Northern Powder River Basin | 2,972 | 4,424 | (1,452) | (33)% |
| Gulf Coast | 1,520 | 1,959 | (439) | (22)% |
| Total | $ 89,298 | $ 112,652 | $ (23,354) | (21)% |

| | | | | |
|---|---|---|---|---|
| *Other coal related revenues* | | | | |
| Override revenue | $ 2,746 | $ 6,444 | $ (3,698) | (57)% |
| Transportation and processing fees | 11,093 | 11,005 | 88 | 1% |
| Minimums recognized as revenue | 2,808 | 5,005 | (2,197) | (44)% |
| Reserve swap | | 8,149 | (8,149) | (100)% |
| Wheelage | 1,789 | 1,995 | (206) | (10)% |
| Total | $ 18,436 | $ 32,598 | $ (14,162) | (43)% |
| Total coal related revenues | $ 107,734 | $ 145,250 | $ (37,516) | (26)% |

*Total coal related revenues.* Total coal related revenues comprised approximately 63% and 80% of our total revenues and other income for the six month periods ended June 30, 2014 and 2013, respectively. The following is a discussion of the major categories of coal related revenue:

*Coal royalty revenues and production*. Coal royalty revenues comprised approximately 52% and 62% of our total revenues and other income for the six month periods ended June 30, 2014 and 2013, 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 $22.5 million or 28% in the six-month period ended June 30, 2014 compared to the same period of 2013, while production decreased 4.4 million tons or 22%.

Production from our properties in the Central Appalachian region declined by 12% due to a combination of the idling of mining units or mines, lower sales volumes from mines on our property and some mining units moving off of our property to adjacent properties in the normal course of their mine plans. In addition, pricing realized by our lessees for both thermal and metallurgical coal in Central Appalachia is generally below the levels of the same period in 2013, 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 one of our lessees curtailing production during the sale of its operations and the successor lessee being slower in increasing production after the acquisition and the timing of sales by some other lessees. In addition prices from the metallurgical sales from our properties were lower than the same period in 2013, creating a higher percentage decrease in coal royalty revenue compared to the decrease in coal production.

With respect to Northern Appalachia, during the six months ended June 30, 2014 there was also a decrease in coal royalty revenue and production. These decreases were primarily due to one lessee moving its longwall mining unit to adjacent property in the normal course of its mine plan and one lessee moving mining units to adjacent property in the normal course of its mine plan. This tonnage decrease was partially offset by another lessee, on which we receive a very low royalty per ton having a greater proportion of its production on our property. Our revenue per ton in the region was also lower primarily due to one of our leases, which has a very low royalty per ton, being a larger proportion of production in the region.

*Illinois Basin*. Coal royalty revenues for the six months ended June 30, 2014 increased $1.0 million when compared to the same period in 2013, and production increased by 11%. Increased production from our Williamson and Hillsboro properties was partially offset by lower sales from our Macoupin property and another property in Indiana where a lessee had a greater proportion of production from adjacent properties. Prices received by our lessees were at or below those received in the same period in 2013, causing a decrease in the revenue per ton for the region.

*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.

*Gulf Coast*. Coal royalty revenue and production for the six months ended June 30, 2014 decreased compared to the same period in 2013 due to lower production by our lessees.

*Other coal related revenues*. Other coal related revenues for the six months ended June 30, 2014 decreased 43% compared to the same period in 2013. The following is a discussion of the revenues derived from each of the major sources of other coal-related revenue:

Override revenue for the six months ended June 30, 2014 decreased by 57% compared to the same period in 2013 due to one lessee moving its mining operations from an area on which we receive an overriding royalty onto property on which we receive coal royalty revenue and other lessees mining fewer tons on properties on which we receive an overriding royalty.

Transportation and processing fees remained nearly the same for the six months of 2014, when compared to the same period in 2013. The increase in revenue for the higher tonnage put through our Williamson facility was offset by the temporary idling of two processing facilities in response to market conditions and timing of tonnage moving across our transportation assets.

Minimums recognized as revenue decreased $2.2 million or 44% for the six months ended June 30, 2014 when compared to the same period in 2013, primarily due to the recoupment period on Foresight Energy s Macoupin mine expiring in 2013 for minimums paid in 2009. Minimums for that lease paid after 2009 have longer recoupment periods. This was partially offset by one of our lessee s previously paid annual minimums expiring and adjustment to the recoupable balance of another lessee.

During the six months ended June 30, 2013, we completed a reserve swap and recognized the associated revenue. We did not have such a reserve swap in the same period in 2014.

Wheelage revenue decreased by 10% for the six months ended June 30, 2014 compared to the same period in 2013. This slight decrease was due to the normal fluctuations of tonnage that are subject to wheelage charges.

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*Aggregates and Industrial Minerals Revenues, and Other Related Income*

| | Six Months Ended June 30, 2014 | Six Months Ended June 30, 2013 | Increase (Decrease) | Percentage Change |
|---|---|---|---|---|
| | (In thousands, except percent and per ton data) | | | |
| | (Unaudited) | | | |
| *Aggregates royalty revenues and production* | | | | |
| Tonnage | 2,142 | 2,746 | (604) | (22)% |
| Aggregates royalty per ton | $ 0.99 | $ 1.20 | $ (0.21) | (18)% |
| Total aggregates royalty revenues | $ 2,125 | $ 3,303 | $ (1,178) | (36)% |
| Other aggregates related revenues | $ 4,834 | $ 2,552 | $ 2,282 | 89% |
| Total aggregates related revenues | $ 6,959 | $ 5,855 | $ 1,104 | 19% |
| Equity and other unconsolidated investment earnings | $ 19,180 | $ 14,930 | $ 4,250 | 28% |
| Total aggregates and industrial minerals revenues, and other related income | $ 26,139 | $ 20,785 | $ 5,354 | 26% |

*Total aggregates and industrial minerals revenues, and other related income*. Total aggregates and industrial minerals revenues, and other related income represented approximately 15% and 11% of our total revenues and other income for the six month periods ended June 30, 2014 and 2013, respectively. The following is a discussion of the major categories of these revenues:

Aggregates royalty revenues decreased 36% and production decreased 22% for the six months ended June 30, 2014, while average royalty per ton decreased 18%. These decreases were primarily due to one lessee moving from property on which we owned the reserves, to property on which we receive an overriding royalty.

Other aggregates related revenues were up $2.3 million or 89% compared to last year due to a lessee relinquishing their recoupments rights on previously paid minimums in 2014 and override revenues increasing on our Washington aggregates property due to a lessee moving from our owned property to an area subject to an override. Override revenues also increased on our frac sand properties by $0.3 million or 21% over the first half of 2013.

*Equity and other unconsolidated investment earnings*. Income from our investment in the OCI Wyoming trona mining and soda ash production business was $19.2 million for the six months ended June 30, 2014 and we received $25.6 million in cash during the first half of 2014. For the same period in 2013, we recorded equity income of $14.9 million and received $26.9 million in cash. This represents an increase in equity income of 28% due to the first quarter of 2014 reflecting a full quarter of revenues as well as improved earnings from OCI Wyoming in 2014 over 2013.

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***Oil and Gas Revenues***

| | Six Months Ended June 30, 2014 | 2013 | Increase (Decrease) | Percentage Change |
|---|---|---|---|---|
| | (In thousands, except percent and per unit data) (Unaudited) | | | |
| *Williston Basin non-operated working interests:* | | | | |
| *Production volumes* | | | | |
| Oil (MBbl) | 207 | N/A | N/A | N/A |
| Natural gas (Mcf) | 112 | N/A | N/A | N/A |
| NGL (MBoe) | 12 | N/A | N/A | N/A |
| *Average sales price per unit* | | | | |
| Oil (Bbl) | $ 95.86 | N/A | N/A | N/A |
| Natural gas (Mcf) | $ 7.54 | N/A | N/A | N/A |
| NGL (Boe) | $ 48.50 | N/A | N/A | N/A |
| *Revenues* | | | | |
| Oil | $ 19,842 | N/A | N/A | N/A |
| Natural gas | 844 | N/A | N/A | N/A |
| NGL | 582 | N/A | N/A | N/A |
| Total | $ 21,268 | N/A | N/A | N/A |
| *Other oil and gas revenues* | | | | |
| Royalty and overriding revenues | $ 6,612 | $ 5,856 | $ 756 | 13% |
| Total oil and gas revenues | $ 27,880 | $ 5,856 | $ 22,024 | 376% |

Oil and gas revenues increased $22.0 million for the six months ended June 30, 2014 when compared to the same period in 2013. The increase is primarily due to revenues from our Williston Basin non-operated working interest properties which were acquired during the second half of 2013. We also saw an increase in royalty revenues from our mineral properties.

***Other Operating Results***

In addition to coal related revenues, aggregates and industrial minerals revenues and other revenues and oil and gas revenues, we generated approximately 5% of our total revenues and other income from other sources for both the three and six month periods of 2014 and 2013. Other sources of revenues primarily include: reimbursements of property taxes from our lessees, rentals, metal revenue and timber royalties.

*Operating costs and expenses.* Included in total expenses are:

Depreciation, depletion and amortization expenses were lower for the three and six months ended June 30, 2014 when compared to the same period for 2013. Coal depletion was down on lower production, partially offset by increased oil and gas depletion for our non-operated working interests that were acquired during the second half of 2013.

General and administrative expenses was virtually flat for the second quarter of 2014 when compared to the same quarter in 2013, while for the six month periods ending June 30, 2014 and 2013 expense decreased $5.6 million. The change in general and administrative expense is primarily due to a decrease in long term incentive plan expense due to the fluctuation in unit price.

*Interest expense.* Interest expense increased approximately $4.6 million and $9.8 million for the three and six months ended June 30, 2014 over the same periods in 2013. The increase reflects the issuance of NRP s 9.125% senior notes issued in September 2013.

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## Liquidity and Capital Resources

### *Cash Flows and Capital Expenditures*

Generally, 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, 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 aggregates/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, 2013. Our capital expenditures, other than for acquisitions, have historically been minimal. However, we incur capital expenditures and operating expenses associated with the non-operated working interests in oil and gas assets. We finance those capital expenditures through a combination of cash flow from operations and borrowings under the NRP Oil and Gas revolving credit facility.

Opco s revolving credit facility does not mature until August 2016 and, as of June 30, 2014, Opco had $285 million in available capacity under the facility. As of June 30, 2014, NRP Oil and Gas had $18.0 million available for borrowing under its revolving credit facility. 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.

In addition to the amounts available under our revolving credit facilities, we had $70.0 million in cash at June 30, 2014. As of the date of this report, NRP has sold 1,438,114 common units through its at-the-market offering ( ATM ) program during 2014 for approximately $23.2 million in gross proceeds, excluding our general partner s capital contribution to maintain its 2% general partner interest in us. During the first six months of 2014, we repaid $48.3 million of principal on Opco s senior notes and repaid $5.0 million on Opco s revolving credit facility, thereby reducing our total outstanding debt by $53.5 million.

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. Other than $81 million in principal repayments due on Opco s senior notes each year for the next several years, we do not have any debt maturing until 2016. As of June 30, 2014, our debt covenant ratios are in compliance for both revolving credit facilities, Opco s term loan facility and Opco s outstanding senior notes. For a more complete discussion of factors that will affect our liquidity, see Item 1A, Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2013.

Net cash provided by operating activities for the six months ended June 30, 2014 and 2013 was $99.6 million and $123.6 million, respectively. The majority of our cash provided by operating activities is generated from coal related royalty revenues, our equity interest in OCI Wyoming and beginning in 2014, oil and gas revenues.

Net cash used in investing activities for the six months ended June 30, 2014 was $4.8 million primarily for additional capital expenditures relating to our 2013 acquisitions of non-operated working interests in producing oil and gas properties as well as a $5 million acquisition of coal reserves in the Illinois Basin offset by a purchase price adjustment of $4.3 million on one of our oil and gas acquisitions and a one-time tax distribution from OCI Wyoming of $3.6 million. Net cash used in investing activities for the six months ended June 30, 2013 was $281.5 million. Substantially all of our 2013 investing activities consisted of the acquisition of the interest in OCI Wyoming, see Note 4. Equity and Other Investments.

Net cash used in financing activities for the six months ended June 30, 2014 was $117.3 million. During the first six months of 2014, we had net proceeds from loans of $2.0 million, net proceeds from equity transactions of $13.4 million, and a capital contribution from our general partner of $0.3 million. These proceeds were offset by loan payments of $53.5 million and distributions to partners of $79.6 million. During the same period for 2013, net cash provided by financing activities was $113.6 million, which included net proceeds from loans of $243.0 million, net proceeds from equity transactions of $75.0 million, and a capital contribution from our general partner of $1.5 million. These proceeds were offset by debt repayments of $79.5 million and distributions to partners of $124.7 million.

***Contractual Obligations and Commercial Commitments***

*NRP Debt*

*Senior Notes*. In September 2013, NRP and NRP Finance as co-issuer completed a private placement of $300 million 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. 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.

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*Opco Debt*

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

- $15.0 million drawn under the floating rate revolving credit facility, due August 2016;
- $99.0 million floating rate term loan, due January 2016;
- $18.5 million of 4.91% senior notes due 2018;
- $107.1 million of 8.38% senior notes due 2019;
- $46.2 million of 5.05% senior notes due 2020;
- $1.3 million of 5.31% utility local improvement obligation due 2021;
- $24.3 million of 5.55% senior notes due 2023;
- $75.0 million of 4.73% senior notes due 2023;
- $150.0 million of 5.82% senior notes due 2024;
- $45.5 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.

*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.

All of Opco s senior notes require annual principal payments in addition to semi-annual interest payments. The scheduled principal payments on Opco s 4.73%, 5.03% and 5.18% senior notes will begin in 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 $285 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 2014, Opco s borrowings and repayments under its credit facility were as follows:

| | **Quarter Ending** | |
|---|---|---|
| | **March 31** | **June 30** |
| | **(In thousands)** | |
| | **(Unaudited)** | |
| Outstanding balance, beginning of period | $ 20,000 | $ 20,000 |
| Borrowings under credit facility | | |
| Less: Repayments under credit facility | | (5,000) |
| Outstanding balance, ending period | $ 20,000 | $ 15,000 |

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Opco s obligations under its credit facility are unsecured but are guaranteed by its subsidiaries. Opco may prepay all amounts outstanding under its credit facility 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 bore interest at a weighted average rate of 2.25% for the six months ended June 30, 2014. We repaid $101 million of the term loan during 2013. The remaining balance of $99.0 million is due in January 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*. 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 oil and gas assets in which it owns non-operated working interests. As of June 30, 2014, the credit facility has a borrowing base of $20.0 million. The credit facility 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 June 30, 2014, NRP Oil and Gas had $2.0 million outstanding under the facility.

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 incurs 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 current ratio of at least 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.

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.

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***Consolidated Debt***

The following table reflects our long-term non-cancelable contractual obligations as of June 30, 2014 (in millions) (unaudited):

| | Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| Contractual Obligations | Total | Remaining 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
| NRP: | | | | | | | |
| Long-term debt principal payments (including current maturities)(1) | $ 300.0 | $ | $ | $ | $ | $ 300.0 | $ |
| Long-term debt interest payments(2) | 123.3 | 13.7 | 27.4 | 27.4 | 27.4 | 27.4 | |
| NRP Oil and Gas: | | | | | | | |
| Long-term debt principal payments | 2.0 | | | | | $ 2.0 | |
| Opco: | | | | | | | |
| Long-term debt principal payments (including current maturities) (3) | 814.5 | 32.5 | 81.0 | 195.0 | 81.0 | 81.0 | 344.0 |
| Long-term debt interest payments(4) | 221.4 | 34.5 | 38.4 | 33.3 | 28.2 | 23.2 | 63.8 |
| Rental leases(5) | 3.1 | 0.4 | 0.7 | 0.7 | 0.7 | 0.6 | |
| Total | $ 1,464.3 | $ 81.1 | $ 147.5 | $ 256.4 | $ 137.3 | $ 434.2 | $ 407.8 |

(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.

(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 December 31, 2013, there was $99.0 million outstanding which is 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 for $0.6 million per year. In addition, BRP leases office space for approximately $100,000 per year. These rental obligations are included in the table above.

***Shelf Registration Statements and At-the-Market Program***

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 on Form S-3 that registered all of the common units held by Adena Minerals. This shelf registration statement was declared effective by the SEC on September 21, 2012. Following the effectiveness of this registration statement, Adena distributed 15,181,716 common units to its shareholders, and we subsequently filed prospectus supplements to register the resale of these common units by those shareholders. The shelf registration statement filed in August 2012 also registered up to $500 million in equity securities to be sold by NRP. On November 12, 2013, we filed a prospectus supplement and entered into an Equity Distribution Agreement relating to the offer and sale from time to time of common units having an aggregate offering price of $75 million through one or more managers acting as sales agents at prices to be agreed upon at the time of sale. Under the terms of the Equity Distribution Agreement, we may also sell common units from time to time to any manager as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to any manager as principal would be pursuant to the terms of a separate terms agreement between NRP and such manager. Sales of common units in this at-the-market ( ATM ) program are made pursuant to the shelf registration statement declared effective in September 2012. For the six months ended June 30, 2014, we sold 1,057,105 common units for an average price of $16.08 for gross proceeds of $17.0 million, including 185,097 common units that initially traded on or prior to June 30, 2014 but that were settled subsequent to June 30, 2014. At June 30, 2014, we had received $14.0 million in gross proceeds and recorded an accounts receivable for the balance of $3.0 million with respect to the units settled subsequent to June 30, 2014.

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On April 12, 2013, we filed a resale shelf registration statement on Form S-3 to register the 3,784,572 common units issued in the January 2013 private placement in connection with the OCI Wyoming acquisition. This shelf registration statement was declared effective by the SEC in May 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 described above, 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 facilities, 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.

**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 $0.4 million at June 30, 2014 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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| | (In thousands) (Unaudited) | | | |
| Reimbursement for services | $ 2,843 | $ 2,912 | $ 5,781 | $ 5,732 |

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, 2013.

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:

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| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| | (In thousands) | | | |
| | (Unaudited) | | | |
| Coal royalty revenues | $ 14,034 | $ 12,340 | $ 26,376 | $ 24,558 |
| Transportation and processing fees | 5,551 | 4,102 | 10,200 | 9,351 |
| Minimums recognized as revenue | | | | 3,477 |
| Override revenue | 847 | 742 | 1,678 | 1,778 |
| Other revenue | | | | 8,149 |
| Coal related revenues | $ 20,432 | $ 17,184 | $ 38,254 | $ 47,313 |

At June 30, 2014, we had amounts due from Cline affiliates totaling $59.5 million, of which $54.1 million was attributable to agreements relating to Sugar Camp. As of June 30, 2014, we had received $79.6 million in minimum royalty payments to date that have not been recouped by Cline affiliates, of which $8.6 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.

***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 June 30, 2014, 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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| | (In thousands) | | | |
| | (Unaudited) | | | |
| Coal royalty revenues | $ 657 | $ 1,051 | $ 1,563 | $ 2,154 |

We also had accounts receivable totaling $0.1 million from Corsa at June 30, 2014.

A fund controlled by Quintana Capital owned a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart s 5-person board of directors. Subsequent to the end of the second quarter of 2013, Taggart was sold to Forge Group, and Quintana no longer retains an interest in Taggart or Forge. We own and lease preparation plants to Forge, which operates the plants. The lease payments were based on the sales price for the coal that was processed through the facilities.

Revenues from Forge for the six months ended June 30, 2013 were $1.8 million. Subsequent to the second quarter of 2013, Forge is no longer considered a related party of NRP.

**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, 2013. 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 at June 30, 2014. 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 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. 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.

## 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 of the coal mined by our lessees. Our lessees sell the coal under various long-term and short-term contracts as well as on the spot market. As is customary in the coal industry, our coal is predominantly sold by our lessees under coal supply contracts that have terms of one year or more. Current conditions in the coal industry may make it difficult for our lessees to extend existing contracts or enter into supply contracts with terms of one year or more. Our lessees failure to negotiate long-term contracts could adversely affect the stability and profitability of our lessees operations and adversely affect our coal royalty revenues. If more coal is sold on the spot market, coal royalty revenues may become more volatile due to fluctuations in spot coal prices.

The market price of soda ash directly affects the profitability of OCI Wyoming s operations. If the market price for soda ash declines, OCI Wyoming s sales will decrease. Historically, the global market and, to a lesser extent, the domestic market for soda ash have been volatile, and those markets are likely to remain volatile in the future. In addition, crude oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. These markets will likely continue to be volatile in the future.

### 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 June 30, 2014, we had $116 million in variable interest rate debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $1.2 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, 2013.

### 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 | 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 | Limited Liability Company Agreement of OCI Wyoming LLC, dated June 30, 2014 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed by OCI Resources LP on July 2, 2014). |
| 31.1* | Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley. |
| 31.2* | Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley. |
| 32.1* | Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350. |
| 32.2* | Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350. |
| 101* | The following financial information from the Quarterly Report on Form 10-Q of Natural Resource Partners L.P. for the quarter ended June 30, 2014, 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: August 8, 2014

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

Date: August 8, 2014

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

Date: August 8, 2014

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