NATURAL RESOURCE PARTNERS LP
Form 10-Q
November 05, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2015

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 ý 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 ý 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	ý	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 ý

At November 2, 2015 there were 122,299,825 Common Units outstanding.

NATURAL RESOURCE PARTNERS, L.P.
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Part 1. Financial Information
Item 1. Consolidated Financial Statements

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands, except for unit information)

	September 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$61,156	$50,076
Accounts receivable, net	54,888	66,455
Accounts receivable—affiliates	7,450	9,494
Inventory	6,849	5,814
Prepaid expenses and other	2,661	4,279
Total current assets	133,004	136,118
Land	25,022	25,243
Plant and equipment, net	71,194	60,093
Mineral rights, net	1,144,809	1,781,852
Intangible assets, net	58,269	60,733
Equity in unconsolidated investment	262,347	264,020
Long-term contracts receivable—affiliate	48,520	50,008
Goodwill	4,840	52,012
Other assets	16,864	14,645
Other assets—affiliate	1,525	—
Total assets	$1,766,394	$2,444,724
LIABILITIES AND CAPITAL		
Current liabilities:		
Accounts payable	$11,377	$22,465
Accounts payable—affiliates	2,566	950
Accrued liabilities	54,895	43,533
Current portion of long-term debt, net	80,983	80,983
Total current liabilities	149,821	147,931
Deferred revenue	79,242	73,207
Deferred revenue—affiliates	83,654	87,053
Long-term debt, net	1,323,708	1,374,336
Long-term debt, net—affiliate	19,923	19,904
Other non-current liabilities	9,839	22,138
Commitments and contingencies (see Note 13)		
Partners' capital:		
Common unitholders' interest (122,299,825 units outstanding)	106,011	709,019
General partner's interest	(60)	12,245
Accumulated other comprehensive loss	(2,350)	(459)
Total partners' capital	103,601	720,805
Non-controlling interest	(3,394)	(650)
Total capital	100,207	720,155
Total liabilities and capital	$1,766,394	$2,444,724

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

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015 (Unaudited)	2014	2015 (Unaudited)	2014
Revenues and other income:				
Coal related revenues	$35,469	$39,675	$94,452	$107,593
Coal related revenues—affiliates	19,535	25,518	70,938	65,334
Aggregates related revenues	42,326	2,655	114,158	9,614
Oil and gas related revenues	12,416	9,601	42,485	37,481
Equity in earnings of unconsolidated investment	12,617	9,685	36,739	28,865
Property taxes	2,528	3,520	8,602	10,865
Other	588	955	5,412	2,727
Total revenues and other income	125,479	91,609	372,786	262,479
Costs and expenses:				
Coal related expenses	649	3,383	2,474	4,623
Coal related expenses—affiliates, net	(68)	—	41	—
Aggregates related expenses, net	31,107	(244)	86,314	(170)
Oil and gas related expenses	3,049	2,147	9,809	6,359
General and administrative	5,140	4,825	14,829	13,543
General and administrative—affiliates	4,144	3,083	11,465	9,177
Depreciation, depletion and amortization	26,624	18,621	82,676	49,618
Property, franchise and other taxes	4,286	4,767	14,490	15,836
Asset impairments	626,838	—	630,641	5,624
Total operating expenses	701,769	36,582	852,739	104,610
Income (loss) from operations	(576,290)	55,027	(479,953)	157,869
Other income (expense)				
Interest expense	(23,711)	(18,862)	(69,997)	(57,759)
Interest income	—	8	16	75
Other expense, net	(23,711)	(18,854)	(69,981)	(57,684)
Net income (loss)	(600,001)	36,173	(549,934)	100,185
Less: net loss attributable to non-controlling interest	1,244	—	—	—
Net income (loss) attributable to NRP	$(598,757)	$36,173	$(549,934)	$100,185
Net income (loss) attributable to partners:				
Limited partners	(586,013)	35,450	(538,166)	98,181
General partner	(12,744)	723	(11,768)	2,004
Basic and diluted net income (loss) per common unit	$(4.79)	$0.32	$(4.40)	$0.89
Weighted average number of common units outstanding	122,300	111,244	122,300	110,504

Net income (loss)	$(600,001)	$36,173	$(549,934)	$100,185
Add: comprehensive income (loss) from unconsolidated investment and other	(1,136)	370	(1,891)	106
Less: comprehensive loss attributable to non-controlling interest	1,244	—	—	—
Comprehensive income (loss) attributable to NRP	$(599,893)	$36,543	$(551,825)	$100,291

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

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Nine Months Ended September 30,	
	2015	2014
	(Unaudited)	
Cash flows from operating activities:		
Net income (loss)	$(549,934)	$100,185
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Asset impairment	630,641	5,624
Depreciation, depletion and amortization	82,676	49,618
Distributions from equity earnings from unconsolidated investment	34,545	32,225
Equity earnings from unconsolidated investment	(36,739)	(28,865)
Gain on reserve swap	(9,290)	(5,690)
Other, net	(3,033)	2,142
Other, net—affiliates	(721)	—
Change in operating assets and liabilities:		
Accounts receivable	11,919	(5,072)
Accounts receivable—affiliates	2,044	(2,881)
Accounts payable	(2,769)	1,662
Accounts payable—affiliates	1,616	94
Accrued liabilities	3,059	993
Deferred revenue	6,035	(81)
Deferred revenue—affiliates	(3,399)	11,426
Accrued incentive plan expenses	(6,417)	(5,445)
Other items, net	1,750	750
Other items, net—affiliates	(633)	411
Net cash provided by operating activities	161,350	157,096
Cash flows from investing activities:		
Acquisition of mineral rights	(35,939)	(14,035)
Acquisition of plant and equipment and other	(8,581)	(207)
Proceeds from sale of plant and equipment and other	11,006	5
Proceeds from sale of mineral rights	6,941	—
Return on equity and other unconsolidated investments	—	3,633
Return on long-term contract receivables—affiliate	2,121	910
Net cash used in investing activities	(24,452)	(9,694)
Cash flows from financing activities:		
Proceeds from loans	100,000	2,000
Proceeds from issuance of common units	—	24,826
Capital contribution by general partner	—	507
Repayment of loans	(151,175)	(69,175)
Distributions to partners	(66,142)	(118,372)
Distributions to non-controlling interest	(2,744)	(974)
Debt issuance costs and other	(5,757)	(601)
Net cash used in financing activities	(125,818)	(161,789)

Net increase (decrease) in cash and cash equivalents	11,080	(14,387)
Cash and cash equivalents at beginning of period	50,076	92,513
Cash and cash equivalents at end of period	$61,156	$78,126
Supplemental cash flow information:		
Cash paid during the period for interest	$57,917	$52,266
Plant, equipment and mineral rights funded with accounts payable or accrued liabilities	$4,465	$—

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

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)
(Unaudited)

	Common Unitholders		General Partner	Accumulated Other Comprehensive Loss	Partners' Capital Excluding Non-Controlling Interest	Non-Controlling Interest	Total Capital
	Units	Amounts					
Balance at December 31, 2014	122,300	$709,019	$12,245	$ (459)	$ 720,805	$ (650)	$ 720,155
Costs associated with equity transactions	—	(22)	—	—	(22)	—	(22)
Distributions to unitholders	—	(64,820)	(1,322)	—	(66,142)	—	(66,142)
Distributions to non-controlling interest	—	—	—	—	—	(2,744)	(2,744)
Net loss	—	(538,166)	(11,768)	—	(549,934)	—	(549,934)
Non-cash contributions	—	—	785	—	785	—	785
Comprehensive loss from unconsolidated investment and other	—	—	—	(1,891)	(1,891)	—	(1,891)
Balance at September 30, 2015	122,300	$106,011	$(60)	$ (2,350)	$ 103,601	$ (3,394)	$ 100,207

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

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. Basis of Presentation

Nature of Business

Natural Resource Partners L.P. (the "Partnership") engages principally in the business of owning, operating, 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. As used in these Notes to Consolidated Financial Statements, the terms "NRP," "we," "us" and "our" refer to Natural Resource Partners L.P. and its subsidiaries, unless otherwise stated or indicated by context.

Principles of Consolidation and Reporting

The accompanying unaudited Consolidated Financial Statements of the Partnership have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP") for interim financial information and with Rule 10-01 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. Certain prior period amounts have been reclassified to conform to the current period presentation. The reclassifications had no effect on the Partnership's overall consolidated financial position, income or cash flows. In our opinion, all adjustments, consisting only of normal recurring adjustments necessary for a fair presentation, have been included. The interim financial statements should be read in conjunction with the audited financial statements and related notes included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2014. Interim results are not necessarily indicative of the results for a full year.

In March 2015, the Partnership recorded an out-of-period adjustment to correct an error in depletion expense related to its oil and gas royalty interests owned by BRP LLC, a joint venture with International Paper Company in which the Partnership owns a 51% interest. Depletion expense for the nine months ended September 30, 2015 included a credit of $3.8 million to adjust the impact of depletion expense recorded in prior periods. After evaluating the quantitative and qualitative aspects of the error and the out-of-period adjustment to the Partnership's financial results, management has determined that the misstatement and the out-of-period adjustment are not material to the prior period financial statements.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") amended its guidance on revenue recognition. The core principle of this amendment is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with earlier adoption not permitted. This guidance can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated financial position, results of operations and cash flows.

In April 2015, the FASB issued authoritative guidance which intended to simplify the presentation of debt issuance costs in financial statements. This guidance requires an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This guidance is effective for annual reporting periods beginning after December 15, 2016. Early adoption is permitted. This guidance will be applied retrospectively to each prior period presented. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated balance sheets.

In July 2015, the FASB issued authoritative guidance which intended to simplify the measurement of inventory. This guidance requires an entity to measure inventory at the lower of cost or net realizable value. The amendments do not apply to inventory that is measured using last-in, first-out or the retail inventory method. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with early adoption permitted. This guidance should be applied on a prospective basis. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated financial position, results of operations and cash flows.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

2. Acquisitions

VantaCore Acquisition

On October 1, 2014, the Partnership completed its acquisition of VantaCore Partners LLC ("VantaCore"), a privately held company specializing in the construction materials industry, for $200.6 million in cash and common units. At the time of acquisition, VantaCore operated three hard rock quarries, six sand and gravel plants, two asphalt plants, one underground limestone mine and a marine terminal. VantaCore is headquarted in Philadelphia, Pennsylvania and its current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

The Partnership accounted for the transaction as a business combination under the acquisition method of accounting. Accordingly, the Partnership conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the acquisition date, while transaction and integration costs associated with the acquisitions were expensed as incurred. The fair value of these assets and liabilities was estimated using a discounted cash flow technique with significant inputs that are not observable in the market and thus represents a Level 3 fair value measurement. The results of operations of the acquisition have been included in our consolidated financial statements since the acquisition date.

In the first quarter 2015, the purchase price allocation was adjusted as more detailed analysis was completed and additional information was obtained about the facts and circumstances for various items of VantaCore's plant and equipment that existed as of acquisition date. As a result of this adjustment, plant and equipment was increased by $22.5 million with a corresponding decrease to goodwill. In the second quarter 2015, the purchase price allocation was adjusted as more detailed analysis was completed and additional information was obtained about the facts and circumstances for VantaCore's right to mine and intangible assets that existed as of the acquisition date. As a result of this adjustment, Mineral rights, net and Intangible assets, net were increased by $24.7 million with a corresponding decrease to Goodwill. Measurement-period adjustments were not material to prior period financial statements and were recorded during the period in which the amount of the adjustment was determined. The accounting for the VantaCore acquisition was completed in the second quarter of 2015 and is summarized as follows:

	October 1, 2014 (In thousands)
Consideration	
Cash	$ 168,978
NRP common units	31,604
Total consideration given	$ 200,582
Allocation of Purchase Price	
Current assets	$ 37,222
Land, property and equipment	62,911
Mineral rights	111,500
Other assets	4,347
Current liabilities	(16,953)
Asset retirement obligation	(3,285)
Goodwill	4,840
Fair value of net assets acquired	$ 200,582

Revenue and net income attributable to the VantaCore during the three months ended September 30, 2015 was $39.2 million and $2.9 million, respectively, and for the nine months ended September 30, 2015 was $107.0 million and $4.5 million, respectively.

Sanish Field Acquisition

On November 12, 2014, the Partnership acquired non-operated oil and gas working interests in the Sanish Field of the Williston Basin from an affiliate of Kaiser-Francis Oil Company for $339.1 million.

The Partnership accounted for the transaction as a business combination under the acquisition method of accounting. Accordingly, the Partnership conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired

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and liabilities assumed at their estimated fair values on the acquisition date, while transaction and integration costs associated with the acquisitions were expensed as incurred. The fair value of these assets and liabilities was estimated using a discounted cash flow technique with significant inputs that are not observable in the market and thus represents a Level 3 fair value measurement. Significant inputs used to determine the fair value include estimates of: (i) reserves, including estimated oil and natural gas reserves and risk-adjusted probably reserves; (ii) future commodity prices; (iii) production costs, (iv) capital expenditures, (v) production and (vi) discount rates. The results of operations of the acquisition have been included in our consolidated financial statements since the acquisition date. The accounting for the Sanish Field acquisition was completed in the second quarter of 2015 without significant changes during the measurement period and is summarized as follows:

	November 12, 2014 (In thousands)
Consideration	
Cash	$ 339,093
Allocation of Purchase Price	
Mineral rights - proven oil and gas properties	298,293
Mineral rights - probable and possible oil and gas resources	40,800
Fair value of net assets acquired	$ 339,093

Revenue and net loss attributable to the Sanish Field acquisition during the three months ended September 30, 2015 was $7.2 million and $197.8 million, respectively, and for the nine months ended September 30, 2015 was $31.6 million and $197.0 million, respectively. The net loss includes non-cash impairment expense of $194.5 million for the three and nine months ended September 30, 2015.

Pro Forma Financial Information

The following unaudited pro forma financial information (in thousands) presents a summary of the Partnership's consolidated results of operations for the three and nine months ended September 30, 2014, assuming the VantaCore and Sanish Field acquisitions had been completed as of January 1, 2014, including adjustments to reflect the values assigned to the net assets acquired:

	Three Months Ended September 30, 2014 (Unaudited)	Nine Months Ended September 30, 2014
Revenues and other income except aggregates related and oil and gas related revenues	$79,256	$215,345
Aggregates related revenues	52,735	134,995
Oil and gas related revenues	25,622	88,150
Total revenues and other income	$157,613	$438,490
Net income	$37,091	$106,615
Basic and diluted net income per common unit	$0.33	$0.95

3. Equity Investment

We account for our 49% investment in Ciner Wyoming LLC (“Ciner Wyoming”, and formerly "OCI Wyoming LLC") using the equity method of accounting. Ciner Wyoming distributed $12.7 million and $10.3 million to us in the three months ended September 30, 2015 and 2014, respectively, and Ciner Wyoming distributed $34.5 million and $35.9 million to us in the nine months ended September 30, 2015 and 2014, respectively.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

The difference between the amount at which our investment in Ciner Wyoming is carried and the amount of underlying equity in Ciner Wyoming's net assets was $155.3 million and $162.7 million as of September 30, 2015 and December 31, 2014, respectively. This excess basis relates to plant, property and equipment and right to mine assets. The excess basis difference that relates to property, plant and equipment is being amortized into income using the straight-line method over a weighted average of 28 years. The excess basis difference that relates to right to mine assets is being amortized into income using the units of production method.

Our equity in the earnings of Ciner Wyoming is summarized as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015 (Unaudited)	2014	2015 (Unaudited)	2014
Income allocation to NRP's equity interests	$13,806	$11,170	$40,319	$33,300
Amortization of basis difference	(1,189)	(1,485)	(3,580)	(4,435)
Equity in earnings of unconsolidated investment	$12,617	$9,685	$36,739	$28,865

The results of Ciner Wyoming's operations are summarized as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015 (Unaudited)	2014	2015 (Unaudited)	2014
Sales	$117,340	$109,785	$359,970	$338,996
Gross profit	32,750	28,487	96,565	83,210
Net income	28,175	22,795	82,283	67,952

The financial position of Ciner Wyoming is summarized as follows (in thousands):

	September 30, 2015 (Unaudited)	December 31, 2014
Current assets	$153,095	$200,622
Noncurrent assets	233,012	202,282
Current liabilities	44,566	47,704
Noncurrent liabilities	127,676	149,192

4. Plant and Equipment

The Partnership's plant and equipment consist of the following (in thousands):

	September 30, 2015 (Unaudited)	December 31, 2014
Plant and equipment at cost	$105,248	$89,759
Construction in process	993	457
Less accumulated depreciation	(35,047)	(30,123)
Total plant and equipment, net	$71,194	$60,093

Depreciation expense related to the Partnership's plant and equipment totaled $3.9 million and $1.3 million for the three months ended September 30, 2015 and 2014, respectively. Depreciation expense related to the Partnership's plant and equipment totaled $12.9 million and $3.8 million for the nine months ended September 30, 2015 and 2014, respectively. The Partnership recorded $0.0 million and $2.3 million of asset impairment expense related to a coal preparation plant for the three and nine months ended September 30, 2015, respectively.

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NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

5. Mineral Rights

The Partnership's mineral rights consist of the following (in thousands):

	September 30, 2015 (Unaudited)	December 31, 2014
Coal	$1,196,091	$1,541,572
Oil and Gas	181,740	560,395
Aggregates	189,640	211,490
Other	14,948	15,014
Less: accumulated depletion and amortization	(437,610)	(546,619)
Total mineral rights, net	$1,144,809	$1,781,852

Depletion expense related to the Partnership's mineral rights totaled $21.8 million and $16.5 million for the three months ended September 30, 2015 and 2014, respectively. Depletion expense related to the Partnership's mineral rights totaled $66.6 million and $43.2 million for the nine months ended September 30, 2015 and 2014, respectively.

Impairment of Mineral Rights

The Partnership has developed procedures to periodically evaluate its long-lived assets for possible impairment. These procedures are performed throughout the year and considers both quantitative and qualitative information based on historic, current and future performance and are designed to identify impairment indicators. If an impairment indicator is identified, additional evaluation is performed for that asset that considers both quantitative and qualitative information. A long-lived asset is deemed impaired when the future expected undiscounted cash flows from its use and disposition is less than the assets' carrying value. Impairment is measured based on the estimated fair value, which is primarily determined based upon the present value of the projected future cash flow compared to the assets' carrying value. The inputs used by management for fair value measurements include significant inputs that are not observable in the market and thus represent a Level 3 fair value measurement for these types of assets. In addition to the evaluations discussed above, specific events such as a reduction in economically recoverable reserves or production ceasing on a property for an extended period may require that a separate impairment evaluation be completed on a significant property. The Partnership believes these discount rates were representative of what market participants would use in pricing its assets.

During the three and nine months ended September 30, 2015, the Partnership identified facts and circumstances that indicated that the carrying value of certain of its mineral rights exceed future cash flows from those assets and recorded non-cash impairment expense as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Impaired Asset Description	2015 (Unaudited)	2014	2015	2014
Oil and gas properties (1)	$335,662	$—	$335,662	$—
Coal properties (2)	247,815	—	249,362	—
Aggregates properties (3)	43,361	—	43,361	—
Total	$626,838	$—	$628,385	$—

(1) Oil and gas property impairment in the third quarter of 2015 primarily resulted from declines in future expected realized commodity prices and reduced expected drilling activity on our acreage. NRP compared net capitalized costs of its oil and natural gas properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted future net cash flows, NRP recorded an impairment for the excess of net capitalized cost over fair value. A discounted cash flow method was used to estimate fair value. Significant inputs used to determine the fair value include estimates of: (i) oil and natural gas reserves and risk-adjusted probable reserves; (ii) future commodity prices; (iii) production costs, (iv) capital expenditures, (v) production and (vi) discount rates. The underlying commodity prices embedded in the Partnership's

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

estimated cash flows are the product of a process that begins with NYMEX forward curve pricing as of the measurement date, adjusted for estimated location and quality differentials.

(2) Coal property impairment in the third quarter of 2015 primarily resulted from the continued deterioration and expectations of further reductions in global and domestic coal demand due to reduced global steel demand, sustained low natural gas prices, and continued regulatory pressure on the electric power generation industry. NRP compared net capitalized costs of its coal properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted future cash flows, NRP recorded an impairment for the excess of net capitalized cost over fair value. Significant inputs used to determine fair value include estimates of future cash flow, discount rate and useful economic life. Estimated cash flows are the product of a process that began with current realized pricing as of the measurement date and included an adjustment for risk related to the future realization of those cash flows.

(3) Aggregates property impairment in the third quarter of 2015 primarily resulted from greenfield development projects that have not performed as projected, leading to recent lease concessions on minimums and royalties combined with the continued regional market decline for certain properties. NRP compared net capitalized costs of its aggregates properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted cash flows, NRP wrote the net cost basis down to management's estimate of fair value. A discounted cash flow model was used to estimate fair value. Significant inputs used to determine fair value include estimates of future cash flow, discount rate and useful economic life. Estimated cash flows are the product of a process that began with current realized pricing as of the measurement date and included an adjustment for risk related to the future realization of those cash flows.

6. Intangible Assets

The Partnership’s intangible assets consist of the following (in thousands):

	September 30, 2015 (Unaudited)	December 31, 2014
Contract intangibles	$81,109	$82,972
Other intangibles	5,076	3,004
Less accumulated amortization	(27,916)	(25,243)
Total intangible assets, net	$58,269	$60,733

Amortization expense related to the Partnership’s intangible assets totaled $1.0 million and $0.9 million for the three months ended September 30, 2015 and 2014, respectively. Amortization expense related to the Partnership’s intangible assets totaled $3.2 million and $2.6 million for the nine months ended September 30, 2015 and 2014, respectively.

7. Debt and Debt—Affiliate

As used in this Note 7, references to “NRP LP” refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC, a wholly owned subsidiary of NRP LP, or any of Natural Resource Partners L.P.’s subsidiaries. References to “Opco” refer to NRP (Operating) LLC and its subsidiaries. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP LP. NRP Finance Corporation (“NRP Finance”) is a wholly owned subsidiary of NRP LP and a co-issuer with NRP LP on the 9.125% senior notes described below.

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As of September 30, 2015 and December 31, 2014, Debt and debt—affiliate consisted of the following (in thousands):

	September 30, 2015 (Unaudited)	December 31, 2014
NRP LP Debt:		
$425 million 9.125% senior notes, with semi-annual interest payments in April and October, due October 2018, $300 million issued at 99.007% and $125 million issued at 99.5%	$422,734	$422,167
Opco Debt:		
$300 million floating rate revolving credit facility, due October 2017	290,000	—
$300 million floating rate revolving credit facility, due August 2016	—	200,000
$200 million floating rate term loan, due January 2016	—	75,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, due in June 2018	13,850	18,467
8.38% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, due in March 2019	85,714	107,143
5.05% senior notes, with semi-annual interest payments in January and July, with annual principal payments in July, due in July 2020	38,462	46,154
5.31% utility local improvement obligation, with annual principal and interest payments, due in March 2021	1,153	1,345
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, due in June 2023	21,600	24,300
4.73% senior notes, with semi-annual interest payments in June and December, with annual principal payments in December, due in December 2023	67,500	67,500
5.82% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, due in March 2024	135,000	150,000
8.92% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, due in March 2024	40,909	45,455
5.03% senior notes, with semi-annual interest payments in June and December, with annual principal payments in December, due in December 2026	161,538	161,538
5.18% senior notes, with semi-annual interest payments in June and December, with annual principal payments in December, due in December 2026	46,154	46,154
NRP Oil and Gas Debt:		
Reserve-based revolving credit facility due November 2019	100,000	110,000
Total debt and debt—affiliate	1,424,614	1,475,223
Less: current portion of long-term debt, net	(80,983)	(80,983)
Total long-term debt and debt—affiliate	$1,343,631	$1,394,240

NRP LP Debt

Senior Notes

In September 2013, NRP LP, together with NRP Finance as co-issuer, issued $300.0 million of 9.125% Senior Notes due 2018 at an offering price of 99.007% of par. Net proceeds after expenses from the issuance of the senior notes

were approximately $289.0 million. The senior notes call for semi-annual interest payments on April 1 and October 1 of each year, and will mature on October 1, 2018.

In October 2014, NRP LP, together with NRP Finance as co-issuer, issued an additional $125.0 million of its 9.125% Senior Notes due 2018 at an offering price of 99.5% of par. The notes constitute the same series of securities as the existing $300.0 million 9.125% senior notes due 2018 issued in September 2013. Net proceeds of $122.6 million from the additional issuance of the Senior Notes were used to fund a portion of the purchase price of NRP's acquisition of non-operated working interests in oil and gas

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assets located in the Williston Basin in North Dakota. The notes call for semi-annual interest payments on April 1 and October 1 of each year and will mature on October 1, 2018.

NRP and NRP Finance have the option to redeem the NRP Senior Notes, in whole or in part, at any time on or after April 1, 2016, at fixed redemption prices specified in the indenture governing the NRP Senior Notes (the "NRP Senior Notes Indenture"). Before April 1, 2016, NRP and NRP Finance may redeem all or part of the NRP Senior Notes at a redemption price equal to the sum of the principal 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 NRP Senior Notes Indenture 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 NRP Senior Notes 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 threshholds.

Opco Debt

All of Opco's debt is guaranteed by its wholly owned subsidiaries and is secured by certain of the assets of Opco and its wholly owned subsidiaries other than NRP Trona LLC, as further described below. As of September 30, 2015 and December 31, 2014, Opco was in compliance with the terms of the financial covenants contained in its debt agreements.

Revolving Credit Facility

In June 2015, Opco entered into a $300.0 million Third Amended and Restated Credit Agreement (the "A&R Revolving Credit Facility"), which amended and restated Opco's $300.0 million Second Amended and Restated Credit Agreement due August 2016. The A&R Revolving Credit Facility matures on October 2, 2017, is guaranteed by all of Opco's wholly owned subsidiaries, and is secured by liens on certain of the assets of Opco and its subsidiaries, as further described below.

Initially, indebtedness under the A&R Revolving Credit Facility bears interest, at Opco's option, at a rate of 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 2.375%; or
- a rate equal to LIBOR plus 3.375%.

Borrowings under the A&R Revolving Credit Facility will bear interest at such rate until the time that Opco delivers quarterly financial statements for the quarter ending September 30, 2015 to the lenders thereunder. Following such delivery date, indebtedness under the A&R Revolving Credit Facility will bear interest, at Opco's option, at a rate of 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 1.50% to 2.50%; or
- a rate equal to LIBOR plus an applicable margin ranging from 2.50% to 3.50%.

The weighted average interest rates for the borrowings outstanding under the A&R Revolving Credit Facility for the nine months ended September 30, 2015 and 2014 were 2.41% and 1.96%, respectively. The weighted average interest rates for the borrowings outstanding under the A&R Revolving Credit Facility for the three months ended September 30, 2015 and 2014 were 3.05% and 1.94%, respectively.

Opco will incur a commitment fee on the unused portion of the revolving credit facility at a rate of 0.50% per annum. Opco may prepay all amounts outstanding under the A&R Revolving Credit Facility at any time without penalty.

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The A&R Revolving Credit Facility contains financial covenants requiring Opco to maintain:

- a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the A&R Revolving Credit Facility) not to exceed:
  - 4.0 to 1.0 for each fiscal quarter ending on or before March 31, 2016;
  - 3.75 to 1.0 for each subsequent fiscal quarter ending on or before March 31, 2017; and
  - 3.5 to 1.0 for each fiscal quarter ending on or after June 30, 2017; and
- a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease expense) of not less than 3.5 to 1.0.

The A&R Revolving Credit Facility contains certain additional customary negative covenants that, among other items, restrict Opco's ability to incur additional debt, grant liens on its assets, make investments, sell assets and engage in business combinations. Included in the investment covenant are restrictions upon Opco's ability to acquire assets where Opco does not maintain certain levels of liquidity. The A&R Revolving Credit Facility also contains customary events of default, including cross-defaults under Opco's senior notes (as described below).

The A&R Revolving Credit Facility is collateralized and secured by liens on certain of Opco's assets with a carrying value of $720.5 million classified as Land, Mineral rights and Plant and equipment on the Partnership's Consolidated Balance Sheet as of September 30, 2015. The collateral includes (1) the equity interests in all of Opco's wholly owned subsidiaries, other than NRP Trona LLC (which owns a 49% non-controlling equity interest in Ciner Wyoming), (2) the personal property and fixtures owned by Opco's wholly owned subsidiaries, other than NRP Trona LLC, (3) Opco's material coal royalty revenue producing properties, (4) real property associated with certain of VantaCore's construction aggregates mining operations, and (5) certain of Opco's coal-related infrastructure assets.

Term Loan

During 2013, Opco entered into a $200.0 million Term Loan facility (the "Term Loan") with a maturity date of January 23, 2016. The weighted average interest rates for the debt outstanding under the Term Loan for the nine months ended September 30, 2015 and 2014 were 2.19% and 2.23%, respectively. The weighted average interest rates for the debt outstanding under the Term Loan for the three months ended September 30, 2015 and 2014 was 2.19% for both periods.

Opco repaid $101.0 million in principal under the Term Loan during the third quarter of 2013, and repaid an additional $24.0 million during the fourth quarter of 2014. In September 2015, Opco repaid the remaining $75.0 million on the term loan using borrowings under the A&R Revolving Credit Facility.

Senior Notes

Opco made principal payments of $56.0 million on its senior notes during the nine months ended September 30, 2015. The Note Purchase Agreements relating to Opco's senior notes contain 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 (as defined in the note purchase agreement) 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 of consolidated indebtedness to consolidated EBITDDA (as defined in the note purchase agreement) 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.

In connection with the entry into the A&R Revolving Credit Facility in June 2015, Opco entered into the Third Amendment to the Note Purchase Agreements (the "NPA Amendment") that provides for the security of the senior notes by the same collateral

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package pledged by Opco and its subsidiaries to secure the A&R Revolving Credit Facility, as described above. In addition, the NPA Amendment includes a covenant that provides that, in the event Opco or any of its subsidiaries is subject to any additional or more restrictive covenants under the agreements governing its material indebtedness (including the A&R Revolving Credit Facility, and all renewals, amendments or restatements thereof), such covenants shall be deemed to be incorporated by reference in the senior notes and the holders of the senior notes shall receive the benefit of such additional or more restrictive covenants to the same extent as the lenders under such material indebtedness agreement.

NRP Oil and Gas Debt

Revolving Credit Facility

In August 2013, NRP Oil and Gas entered into a 5-year, $100.0 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. In connection with the closing of the Sanish Field acquisition in November 2014, the credit facility was amended to increase its size to $500.0 million with an initial borrowing base of $137.0 million, and the maturity date thereof was extended to November 2019.

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. In April 2015, the lenders completed their semi-annual redetermination of the borrowing base under the NRP Oil and Gas revolving credit facility and the $137.0 million borrowing base under that facility was redetermined to $105.0 million. The Partnership repaid $10.0 million of outstanding borrowings under the NRP Oil and Gas revolving credit facility during the nine months ended September 30, 2015. At September 30, 2015 and December 31, 2014, there was $100.0 million and $110.0 million, respectively, outstanding under the NRP Oil and Gas revolving credit facility.

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 the Partnership nor any of its other subsidiaries is a guarantor of such facility. The weighted average interest rates for the debt outstanding under the credit facility for each of the nine month periods ended September 30, 2015 and 2014 was 2.57% and 1.90%, respectively. The weighted average interest rates for the debt outstanding under the credit facility for each of the three month periods ended September 30, 2015 and 2014 were 2.70% and 1.90%, respectively.

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 1.50% to 2.50%.

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:

•

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.

As of September 30, 2015 and December 31, 2014, NRP Oil and Gas was in compliance with the terms of the financial covenants contained in its credit facility.

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8. Fair Value Measurements

The Partnership's financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amounts reported on our Consolidated Balance Sheets for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to their short-term nature. The following table (in thousands) shows the carrying amount and estimated fair value of our other financial instruments:

	September 30, 2015		December 31, 2014	
	Carrying Amount (Unaudited)	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Assets				
Contracts receivable—affiliate, current and long-term (1)	$5,068	$5,381	$4,870	$5,162
Debt and debt—affiliate				
NRP LP senior notes (2)	$422,734	$307,063	$422,167	$423,780
Opco senior notes and utility local improvement obligation (3)	$611,880	$442,084	$668,056	$672,740
Opco revolving credit facility and term loan facility (4)	$290,000	$290,000	$275,000	$275,000
NRP Oil and Gas revolving credit facility (4)	$100,000	$100,000	$110,000	$110,000

(1) The Level 3 fair value is estimated by management using comparable term risk-free treasury issues with a market rate component determined by current financial instruments with similar characteristics.

(2) The Level 1 fair value is based upon quotations obtained for identical instruments on the closing trading prices near quarter end.

(3) The Level 3 fair value is estimated by management using quotations obtained for comparable instruments on the closing trading prices near quarter end.

(4) The Level 3 fair value approximates the carrying amount because the interest rates are variable and reflective of market rates and the Partnership has the ability to repay this debt at any time without penalty.

The March 31, 2015 estimated fair value of the NRP LP senior notes and Opco senior notes and local utility improvement obligation were presented incorrectly as $417.0 million and $629.5 million, respectively, and should have been presented as $378.3 million and $557.9 million, respectively. The estimated fair value disclosure had no impact on the Partnership's overall financial position, income or cash flows.

9. Related Party Transactions

Reimbursements to Affiliates of our General Partner

The Partnership's general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with the partnership agreement, the general partner and its affiliates are reimbursed for expenses incurred on the Partnership's behalf. 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, Quintana Minerals Corporation and Western Pocahontas Properties Limited Partnership (“WPPLP”). In addition, the Partnership receives non-cash equity contributions from its general partner related to compensation paid directly by the general partner and not reimbursed by the Partnership. These amounts are presented as non-cash equity contributions on our Consolidated Statements of Partners' Capital.

The Partnership had Accounts payable—affiliates to Quintana Minerals Corporation of $0.7 million and $0.6 million at September 30, 2015 and December 31, 2014, respectively, for services provided by Quintana Minerals Corporation to the Partnership. The Partnership had Accounts payable—affiliates to WPPLP of $1.9 million and $0.4 million at September 30, 2015

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and December 31, 2014, respectively. The Partnership had Accounts receivable—affiliates from WPPLP of $0.1 million and $0.0 million at September 30, 2015 and December 31, 2014, respectively.

Direct general and administrative expenses charged to the Partnership by its general partner for services performed by WPPLP and Quintana Minerals Corporation are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(Unaudited)			
General and administrative—affiliates	$4,144	$3,083	$11,465	$9,177

The Partnership also leases an office building in Huntington, West Virginia from WPPLP and recorded $0.2 million and $0.5 million in General and administrative—affiliates in each of the three and nine months ended September 30, 2015 and 2014, respectively.

Cline Affiliates

Various companies controlled by Chris Cline, including Foresight Energy LP, 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 in NRP's general partner, as well as approximately 4.9 million of NRP's common units. Coal related revenues from Foresight Energy LP ("Foresight Energy") totaled $18.7 million and $24.9 million for the three months ended September 30, 2015 and 2014, respectively. Coal related revenues from Foresight Energy totaled $68.6 million and $63.1 million for the nine months ended September 30, 2015 and 2014, respectively.

As of September 30, 2015 and December 31, 2014 the Partnership had Accounts receivable—affiliates from Foresight Energy of $7.2 million and $9.2 million, respectively. As of September 30, 2015, the Partnership had received $83.4 million in minimum royalty payments to date that have been recorded as Deferred revenue—affiliates since they have not been recouped by Foresight Energy.

The Partnership owns and leases rail load out and associated facilities to Foresight Energy at Foresight Energy's Sugar Camp mine. The lease agreement is accounted for as a direct financing lease. Total projected remaining payments under the lease at September 30, 2015 were $82.7 million with unearned income of $36.2 million, and the net amount receivable was $46.5 million, of which $2.1 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliate on the accompanying Consolidated Balance Sheets.

Total projected remaining payments under the lease at December 31, 2014 were $86.3 million with unearned income of $39.0 million and the net amount receivable was $47.3 million, of which $1.8 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliates on the accompanying Consolidated Balance Sheets.

The Partnership holds a contractual overriding royalty interest from a subsidiary of Foresight Energy that provides for payments based upon production from specific tons at Foresight Energy's 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 September 30, 2015 was $5.1 million, of which $1.0 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliate. The net amount receivable under the agreement as of December 31, 2014 was $5.6 million, of which $1.1 million is included in Accounts receivable—affiliate while the remaining is included in Long-term contracts receivable—affiliate on the accompanying Consolidated Balance Sheets.

During the nine months ended September 30, 2015 and 2104 the Partnership recognized a gain of $9.3 million and $5.7 million, respectively, on a reserve swap at Foresight Energy's Williamson mine. The gain is included in Coal related revenues—affiliates on our Consolidated Statements of Comprehensive Income. The Level 3 fair value of the reserves was estimated using a discounted cash flow model. The expected cash flows were developed using estimated annual sales tons, forecasted sales prices and anticipated market royalty rates.

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Long-Term Debt—Affiliate

Donald R. Holcomb, one of the Partnership's directors, is a manager of Cline Trust Company, LLC, which owns approximately 5.35 million of the Partnership's common units and $20.0 million in principal amount of the Partnership's 9.125% Senior Notes due 2018. The members of the Cline Trust Company are four trusts for the benefit of the children of Chris Cline, each of which owns an approximately equal membership interest in the Cline Trust Company. Mr. Holcomb also serves as trustee of each of the four trusts. Cline Trust Company, LLC purchased the $20.0 million of the Partnership's 9.125% Senior Notes due 2018 in the Partnership's offering of $125.0 million additional principal amount of such notes in October 2014 at the same price as the other purchasers in that offering. The balance on this portion of the Partnership's 9.125% Senior Notes due 2018 was $19.9 million as of September 30, 2015 and is included in Long-term debt, net—affiliate on the accompanying Consolidated Balance Sheet.

Quintana Capital Group GP, Ltd.

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

At September 30, 2015, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp. ("Corsa"), 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. Coal related revenues from Corsa totaled $0.9 million and $0.7 million and $2.4 million and $2.2 million for the three and nine months ended September 30, 2015 and 2014, respectively.

As of September 30, 2015, the Partnership had recorded $0.3 million in minimum royalty payments to date as deferred revenue-affiliates since they have not been recouped by Corsa. The Partnership also had Accounts receivable—affiliates totaling $0.2 million and $0.3 million from Corsa at September 30, 2015 and December 31, 2014, respectively.

WPPLP Production Royalty and Overriding Royalty

For the three months ended September 30, 2015, we reversed Coal related expenses—affiliates by $0.1 million related to a non-participating production royalty payable to WPPLP pursuant to a conveyance agreement entered into in 2007. This reversal during the third quarter brings the Partnership's nine month Coal related expenses—affiliates, net to nearly zero. The Partnership had Other assets—affiliate from WPPLP of $1.5 million and $0.0 million at September 30, 2015 and December 31, 2014, respectively, related to an non-production royalty receivable from WPPLP for overriding royalty interest on a mine.

10. Major Lessees

Revenues from lessees that exceeded ten percent of total revenues and other income for any of the periods presented below are as follows (in thousands except for percentages):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2015 (Unaudited)		2014		2015 (Unaudited)		2014	
	Revenues	Percent	Revenues	Percent	Revenues	Percent	Revenues	Percent
Foresight Energy and its affiliates	$18,677	15%	$24,863	27%	$68,556	18%	$63,116	24%
Alpha Natural Resources	15,429	12%	14,406	16%	33,201	9%	38,857	15%

The Partnership has a significant concentration of revenues with Foresight Energy and Alpha Natural Resources. The exposure is spread out over a number of different mining operations and leases. During the three months ended September 30, 2015, total revenues and other income from Alpha Natural Resources included a $6.0 million non-recurring lease assignment fee.

11. Long-Term 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. Under the plan a grantee will receive the market value of a common unit in cash upon vesting. A summary of activity in the outstanding grants during 2015 is as follows (in thousands):

	Phantom Units
Outstanding grants at January 1, 2015	1,153
Grants during the year	508
Grants vested and paid during the year	(290)
Forfeitures during the year	(49)
Outstanding grants at September 30, 2015	1,322

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 0.37% to 1.01% and 49.55% to 75.34%, respectively, at September 30, 2015. The Partnership's average historical distribution rate of 7.69% and historical forfeiture rate of 5.71% were used in the calculation at September 30, 2015. The Partnership recorded a credit to general and administrative expenses ("G&A expenses") related to its long term incentive plan of $0.2 million and $1.7 million for the three and nine months ended September 30, 2015, respectively, due to the decline in the market price of the Partnership's common units during 2015. For the three and nine months ended September 30, 2014, the Partnership recorded G&A expenses of $1.1 million and $1.5 million, respectively. In connection with the Long-Term Incentive Plan, payments are typically made during the first quarter of the year. Payments of $4.4 million and $6.5 million were made during the nine month periods ended September 30, 2015 and 2014, respectively.

In connection with the phantom unit awards, the Compensation, Nominating and Governance 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 between the date the units are granted and the vesting date. The DERs are payable in cash upon vesting but may be subject to forfeiture if the grantee ceases employment prior to vesting.

The unaccrued cost associated with the unvested outstanding grants and related DERs at September 30, 2015 and September 30, 2014 was $2.3 million and $7.7 million, respectively.

12. Cash Distributions

The following table shows the distributions paid by the Partnership during the nine months ended September 30, 2015 and 2014:

			Total Distributions (In thousands)		
Date Paid	Period Covered by Distribution	Distribution per Common Unit	Common Units	GP Interest	Total
2015					
February 13, 2015	October 1 - December 31, 2014	$0.35	$42,804	$874	$43,678
May 14, 2015	January 1 - March 31, 2015	0.09	11,007	225	11,232
August 14, 2015	April 1 - June 30, 2015	0.09	11,009	223	11,232

2014

January 31, 2014	October 1 - December 31, 2013	0.35	38,433	785	39,218
May 14, 2014	January 1 - March 31, 2014	0.35	38,634	787	39,421
August 14, 2014	April 1 - June 30, 2015	0.35	38,938	795	39,733

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

13. Commitments and Contingencies

The purchase agreement for the acquisition of the Partnership's interest in Ciner Wyoming requires it to pay additional contingent consideration to Anadarko to the extent certain performance criteria described in the purchase agreement are met at Ciner Wyoming in any of the years 2013, 2014 or 2015. During the first quarters of 2014 and 2015, the Partnership paid $0.5 million and $3.8 million, respectively, in contingent consideration to Anadarko. As of September 30, 2015, the Partnership has estimated and recorded $8.8 million as an accrued liability on its consolidated Balance Sheet, payable in the first quarter of 2016 with respect to 2015. The Partnership has no obligation to pay contingent consideration with respect to any period after 2015.

In March 2014, Anadarko gave the Partnership written notice that it believed certain reorganization transactions conducted in 2013 within the OCI organization triggered an acceleration of the Partnership's obligation under the purchase agreement with Anadarko to pay the additional contingent consideration in full and demanded immediate payment of such amount. The Partnership disagreed with Anadarko's position in a written response provided to them in April 2014. In April 2015, Anadarko sent a written request for additional information regarding the OCI reorganization and indicated that they were still considering this claim against the Partnership. The Partnership responded in writing in May 2015 and does not believe the reorganization transactions triggered an obligation to pay the additional contingent consideration. The Partnership will continue to engage in discussions with Anadarko to resolve the issue to the extent necessary. However, if Anadarko were to pursue and prevail on such a claim, the Partnership would be required to pay an amount to Anadarko in excess of the amounts already paid, together with the $8.8 million accrual described above, up to the maximum amount of the additional contingent consideration, minus a deductible. Under the purchase agreement, the maximum cumulative amount of additional contingent consideration is an amount equal to the net present value of $50.0 million. Any additional amount paid by the Partnership would be considered to be additional acquisition consideration and added to Equity and other unconsolidated investments.

Since 2013, several citizen group lawsuits have been filed against landowners alleging ongoing discharges of pollutants, including selenium and conductivity, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property had been closed, the property had been reclaimed, and the state reclamation bond had been released. Any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site could result in substantial compliance costs or fines and would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations. A subsidiary of the Partnership has been named as a defendant in one of these lawsuits. Given the early stage of this ongoing litigation, the Partnership currently cannot reasonably estimate a range of potential loss, if any, related to this matter.

14. Subsequent Events

The following represents material events that have occurred subsequent to September 30, 2015 through the time of the Partnership's filing of this Quarterly Report on Form 10-Q with the Securities and Exchange Commission:

Distribution Declared

On October 21, 2015, the Board of Directors of GP Natural Resource Partners LLC declared a distribution of $0.045 per unit to be paid by the Partnership on November 13, 2015 to unitholders of record on November 5, 2015.

NRP Oil and Gas Revolving Credit Facility

In October 2015, the lenders under the NRP Oil and Gas revolving credit facility completed their semi-annual redetermination of the borrowing base under the NRP Oil and Gas revolving credit facility and the $105.0 million borrowing base was redetermined to $88.0 million. NRP Oil & Gas repaid $15.0 million under the facility in October 2015, leaving $85.0 million of debt outstanding under the facility as of the date of this report.

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

Information Regarding Forward-Looking Statements

Statements included in this Form 10-Q may constitute forward-looking statements. In addition, we and our representatives may from time to time make other oral or written statements which 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, oil, natural gas, aggregates and industrial minerals;
- estimated revenues, expenses and results of operations;
- the amount, nature and timing of capital expenditures;
- our ability to make acquisitions and integrate the acquisitions we do make;
- our liquidity and access to capital and financing sources;
- projected production levels by our lessees, VantaCore Partners LLC ("VantaCore"), and the operators of our oil and gas working interests;
- Ciner Wyoming LLC'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, 2014 for important factors that could cause our actual results of operations or our actual financial condition to differ.

As used herein, 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, a wholly owned subsidiary of NRP, 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.

Introduction

The following discussion and analysis presents management's view of our business, financial condition and overall performance and should be read in conjunction with our consolidated financial statements and footnotes included elsewhere in this filing. Our discussion and analysis consists of the following subjects:

- Executive Overview
- Results of Operations
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Related Party Transactions
- Recent Accounting Standards

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Executive Overview

We are a diversified natural resource company engaged 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, crude oil and natural gas, construction aggregates, frac sand and other natural resources. For the nine months ended September 30, 2015, we recorded revenues and other income of $372.8 million and Adjusted EBITDA of $221.9 million. Adjusted EBITDA is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA to net income, see "-Results of Operations-Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014-Adjusted EBITDA (Non-GAAP Financial Measure)."

Our coal reserves are located in the three major U.S. coal producing regions: Appalachia, the Illinois Basin and the Western United States. We also own lignite reserves in the Gulf Coast region. We do not operate any coal mines, but lease our coal 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 coal infrastructure assets that generate additional coal related revenues, primarily in the Illinois Basin.

We own a 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. Ciner Resources LP (formerly 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. We do not anticipate that this transaction will have any impact on the operations of Ciner Wyoming LLC (formerly OCI Wyoming LLC) going forward or future cash distributions to our interest.

We own or lease aggregates and industrial minerals located in a number of states across the country. We derive a small percentage of our aggregates and industrial minerals revenues by leasing our owned reserves to third party operators who mine and sell the reserves in exchange for royalty payments. However, the majority of our aggregates and industrial minerals revenues come through our ownership of VantaCore, which we acquired in October 2014. VantaCore specializes in the construction materials industry and operates four hard rock quarries, one underground limestone mine, six sand and gravel plants, two asphalt plants and a marine terminal. VantaCore's operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

We own various interests in oil and gas properties that are located in the Williston Basin, the Appalachian Basin, Louisiana and Oklahoma. Our interests in the Appalachian Basin, Louisiana and Oklahoma are minerals and royalty interests, while in the Williston Basin we own non-operated working interests. Our Williston Basin non-operated working interest properties generate the majority of our oil and gas revenues and include the properties acquired in the Sanish Field from an affiliate of Kaiser-Francis Oil Company in November 2014.

Current Liquidity Position

At September 30, 2015, our liquidity consisted of $61.2 million in cash and $15.0 million in combined borrowing capacity under our revolving credit facilities. During the nine months ended September 30, 2015, we reduced our debt by a net amount of $51.2 million. Opco's $300.0 million revolving credit facility matures in October 2017, and as of September 30, 2015, we had $290.0 million outstanding thereunder. We borrowed $75.0 million under Opco's revolving credit facility in September 2015 in order to repay Opco's term loan in full. In October 2015, the borrowing base under the NRP Oil and Gas revolving credit facility was redetermined to $88.0 million, and we repaid $15.0 million under that credit facility, reducing our outstanding borrowings thereunder to $85.0 million. As of the date of this report, the combined borrowing capacity under our two revolving credit facilities is $13.0 million.

While we believe we have sufficient liquidity to meet our current financial needs, we have significant debt service requirements, including $80.8 million in principal payments on Opco's senior notes each year through 2018, and our operating results continue to be impacted by the adverse conditions in the commodity markets. In April 2015, we announced a long-term plan to strengthen our balance sheet, reduce debt and enhance liquidity in order to reposition the partnership for future growth. As part of that plan, we reduced our cash distributions with respect to the first and second quarters of 2015 to $0.09 per common unit, a 75% decrease from the distribution paid with respect to fourth quarter of 2014. In October 2015, the Board declared a distribution of $0.045 per common unit with respect to the third quarter of 2015, representing an additional 50% reduction in the distribution paid with respect to the second quarter of 2015. The cash savings resulting from the distribution reductions are being used primarily to repay debt. In addition, we have announced our intention to commence processes to sell certain assets in furtherance of achieving the goals set out in our strategic plan. We have also taken steps to reduce general and administrative and other overhead costs in connection with these efforts. If we are unable to complete any asset sales and conditions in the coal and oil and gas markets continue to deteriorate, our liquidity and our ability to comply with the financial and other restrictive covenants contained in our debt agreements will be adversely affected.

Current Results/Market Outlook

Our revenues and other income from sources other than coal represented 56% of our total revenues and other income in the first nine months of 2015, as compared to 34% of total revenues and other income in the first nine months of 2014. This increase is due primarily to our diversification efforts, including our acquisition of VantaCore, which generated aggregates related revenues of $106.6 million during the first nine months of 2015. As an operating construction aggregates business, VantaCore generates higher revenues but experiences lower profit margins than our royalty businesses. Coal royalty revenues were down 19% for the first nine months of 2015 compared to the first nine months of 2014, due primarily to lower coal prices in the each of the Appalachian regions during the period and in the Illinois Basin as a result primarily of lower coal production during the period. This decrease in coal royalty revenues was partially offset by an increase in other coal related revenues, which increased 58% over the 2014 period, due to increased minimums recognized as revenue, a coal reserve swap, a condemnation payment and the receipt of a fee in connection with the assignment of one of our leases. During the first nine months of 2015, our investment in Ciner Wyoming's trona mining and soda ash production operations contributed $36.7 million in other income, up $7.9 million from the first nine months of 2014, and our oil and gas revenues increased 13% over the first nine months of 2014 due to higher production volumes resulting from the Sanish Field acquisition, which were largely offset by lower oil and natural gas prices.

Coal. Both the thermal and metallurgical coal markets remain severely challenged, and we do not anticipate that either market will recover in the near term. We expect that coal producers will continue to cut production and idle additional mines in response to market conditions, but we do not know to what extent our properties may be affected. A number of coal producers have filed petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code, and additional producers may file for bankruptcy over the next few months. Historically, our leases have generally been assumed and all pre-petition bankruptcy amounts have been cured in full in our lessees' bankruptcy processes. In October 2015, Patriot Coal Corporation completed the sale of its assets to Blackhawk Mining and the Virginia Conservation Legacy Fund in accordance with its bankruptcy plan. All of our leases were assumed and assigned in the sale process, and we expect to receive full pre-petition cure payments. Alpha Natural Resources, which is our second largest lessee, filed for Chapter 11 bankruptcy protection in August 2015. Alpha has continued operating and paying royalties to us following the bankruptcy filing. However, we expect that Alpha will reduce production and/or idle mines during its bankruptcy process, which would result in decreased royalty payments to us to the extent such production cuts or idlings are on our properties. We estimate that Alpha owes us approximately $3.2 million in pre-petition royalties, minimum payments and property tax reimbursements, and we expect to receive all pre-petition amounts due to us with respect to any leases that are assumed in the bankruptcy process.

While producers of Central Appalachian thermal coal have struggled for an extended period due to the high cost nature of their operations, production from our Illinois Basin properties also decreased by 18% for the first nine months of 2015 as compared to the same period in 2014. Part of the decrease in production from our Illinois Basin properties is attributable to the idling of Foresight Energy LP's Deer Run mine (which we also refer to as our Hillsboro property) as a result of elevated carbon monoxide levels at the mine beginning in March 2015. In July 2015, we received a notice from Foresight Energy declaring a resulting force majeure event at the Deer Run mine. While we are disputing Foresight Energy's claim, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us quarterly minimum deficiency payments with respect to the Deer Run mine until mining resumes. Under the lease for the Deer Run mine, Foresight Energy is required to make minimum deficiency payments to us of $7.5 million per quarter. The amount payable to us as the minimum deficiency payment with respect to any quarter is reduced by the amount of coal royalties actually paid to us for tonnage sold at the mine with respect to that quarter. We received royalty payments on tonnage sold from coal stockpiles at the Deer Run mine during the second and third quarters of 2015, but we expect that the stockpiles will be depleted early in the fourth quarter. Foresight Energy's failure to make the deficiency payments with respect to the second and third quarters resulted in a negative cash impact to us of $9.2 million.

The metallurgical coal markets continued to deteriorate during the third quarter of 2015, and the fourth quarter 2015 metallurgical coal benchmark price was set at a multi-year low. We derived approximately 38% of our coal royalty revenues and 30% of the related production from metallurgical coal during the first nine months of 2015. The global metallurgical coal market continues to suffer from oversupply driven in part by reduced demand from China. Domestic coal producers are also burdened by the effects of relatively strong domestic dollar which increases the production cost of U.S. coal producers relative to foreign producers.

Soda Ash. Our trona mining and soda ash refinery investment performed in line with our expectations during the first nine months of 2015 with record soda ash production volumes. The international market for soda ash continues to grow and Ciner Wyoming's international sales were better than expected. Domestic sales volumes, which are typically sold at higher prices than soda ash sold internationally, have remained relatively stable. The cash we receive from Ciner Wyoming is in part determined by the quarterly distributions declared by Ciner Resources LP, which has increased its quarterly distribution with respect to each of the last four quarters. The distribution declared with respect to the third quarter of 2015 represents a 5% increase over the distribution paid with respect to the third quarter of 2014.

Aggregates. VantaCore's construction aggregates mining and production business is largely dependent on the strength of the local markets that it serves and is also seasonal. VantaCore's Laurel Aggregates operation in southwestern Pennsylvania serves producers and oilfield service companies operating in the Marcellus and Utica Shales and was impacted during the first nine months of 2015 by the slowing pace of exploration and development of natural gas in those areas due to low natural gas prices. Increased local construction activity partially offset these declines during the first nine months of 2015, but we expect that Laurel's business will continue to be impacted by decreased natural gas development activities. VantaCore's operations based in Clarksville, Tennessee and Baton Rouge, Louisiana depend on the pace of commercial and residential construction in those areas. The Clarksville operation performed in line with expectations during the third quarter, while the Baton Rouge operation volumes were lower than expected. In June 2015, VantaCore purchased a hard rock quarry operation located on the Tennessee River near Grand Rivers, Kentucky from one of NRP's aggregates lessees that had previously idled the operation. This operation continues to lease reserves from NRP and sells its produced limestone aggregates in both the local market and downstream to river-based markets.

Oil and Natural Gas. Global oil prices declined further in the third quarter of 2015 and remain significantly lower than the same period in 2014. Although domestic crude oil production has shown signs of decline, inventories remain above the five year average indicating continued excessive supply. Production of crude is estimated to continue to decline as a result of reduced development drilling activities. Natural gas prices have also shown recent declines due to reduced demand and increased inventories. Our oil and gas revenues will continue to fluctuate with changes in prices for oil and natural gas. As of the date of this filing, we have not hedged any of our future oil or natural gas production.

Impairment of Mineral Rights. During the third quarter, we identified facts and circumstances that indicated that the carrying value of certain mineral rights may exceed expected future cash flows from those assets, and as a result, we recognized $626.8 million of impairment expense during the three months ended September 30, 2015. Oil and gas property impairments of $335.7 million primarily resulted from declines in future expected realized commodity prices and reduced expected drilling activity on our acreage. Coal property impairments of $247.8 million primarily resulted from idled operations in Appalachia combined with the continued deterioration in the coal markets and expectations of further reductions in global and domestic coal demand due to reduced global steel demand, low natural gas prices, and continued regulatory pressure on the electric power generation industry. Aggregates property impairments of $43.4 million primarily resulted from greenfield development projects that have not performed as projected, leading to recent lease concessions on minimums and royalties combined with the continued regional market decline for certain properties. With continued weakness in the commodity markets, we will continue to closely monitor our assets for impairment.

Results of Operations

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Adjusted EBITDA (Non-GAAP Financial Measure)

Adjusted EBITDA increased $10.0 million, or 15%, to $78.5 million in the three months ended September 30, 2015. This increase in Adjusted EBITDA is primarily related to the inclusion of VantaCore and the Sanish Field in our operating results in 2015, as well as increased distributions from our soda ash business, which was partially offset by lower coal royalty revenues in 2015 as compared to 2014.

Adjusted EBITDA is a non-GAAP financial measure that we define as net income less equity earnings in unconsolidated investment, gains on reserve swaps and income to non-controlling interest; plus distributions from

equity earnings in unconsolidated investment, interest expense, gross, depreciation, depletion and amortization and asset impairments. Adjusted 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. Adjusted 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 financial activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDA provides no information regarding a partnership's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax positions. Adjusted 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 Adjusted EBITDA is a useful measure because it is widely used by financial analysts, investors and rating agencies for comparative purposes. Adjusted EBITDA is also a financial measure widely used by investors in the high-yield bond market. There are significant limitations to using Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain 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 Adjusted EBITDA reported by different companies. The following table (in thousands) reconciles net income to Adjusted EBITDA for the three months ended September 30, 2015 and 2014:

	Three Months Ended September 30,	
	2015	2014
	(unaudited)	
Net income (loss)	$(600,001)	$36,173
Less: equity earnings in unconsolidated investment	(12,617)	(9,685)
Less: gain on reserve swap	—	(5,690)
Add: asset impairments	626,838	—
Add: depreciation, depletion and amortization	26,624	18,621
Add: interest expense, gross	23,711	18,862
Add: distributions from equity earnings in unconsolidated investment	12,740	10,290
Add: loss to non-controlling interest	1,244	—
Adjusted EBITDA	$78,539	$68,571

Adjusted EBITDA presented in the table above differs from the EBITDDA definitions contained in Opco's debt agreements. 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 Note 7. "Debt and Debt—Affiliate" in the consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for a description of Opco's debt agreements.

Distributable Cash Flow (Non-GAAP Financial Measure)

Our distributable cash flow represents net cash provided by operating activities, plus returns on unconsolidated equity investments, proceeds from sales of assets, and returns on long-term contract receivables—affiliate less maintenance capital expenditures and distributions to non-controlling interest. 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. The following table (in thousands) reconciles net cash provided by operating activities to distributable cash flow for the three months ended September 30, 2015 and 2014:

	Three Months Ended September 30,	
	2015	2014
	(Unaudited)	
Net cash provided by operating activities	$55,240	$57,458
Add: proceeds from sale of plant and equipment and other	5,751	5
Add: proceeds from sale of mineral rights	1,660	—
Add: return on long-term contract receivables—affiliate	984	310
Less: maintenance capital expenditures (1)	(5,628)	—
Distributable cash flow	$58,007	$57,773

(1) Maintenance capital expenditures primarily consist of costs to maintain the long-term productive capacity of our oil and gas non-operating working interest business and VantaCore.

Diversified Natural Resource Revenues and Other Income

The following table shows our diversified sources of revenues and other income in the three months ended September 30, 2015 and 2014:

	Coal Related Revenues (Including Affiliates)		Aggregates Related Revenues		Industrial Minerals Other Income (Ciner Wyoming)		Oil and Gas Related Revenues		Other Revenues		Total
	(Unaudited) (In thousands except for percentages)										
2015											
Revenues	$55,004		$42,326		$ 12,617		$12,416		$3,116		$125,479
Percentage of total	44	%	34	%	10	%	10	%	2	%	
2014											
Revenues	$65,193		$2,655		$ 9,685		$9,601		$4,475		$91,609
Percentage of total	71	%	3	%	11	%	10	%	5	%	

Coal Related Revenues (including affiliates)

Total coal related revenues comprised approximately 44% and 71% of our total revenues and other income for the three months ended September 30, 2015 and 2014, respectively. The table below presents coal royalty production and revenues derived from our major coal producing regions and the significant categories of other coal related revenues:

	Three Months Ended September 30,		Increase (Decrease)	Percentage Change
	2015	2014		
	(In thousands, except percent and per ton data) (Unaudited)			
Coal royalty production (tons)				
Appalachia				
Northern	1,518	2,060	(542)	(26)%
Central	4,642	5,432	(790)	(15)%
Southern	851	1,017	(166)	(16)%
Total Appalachia	7,011	8,509	(1,498)	(18)%
Illinois Basin	2,722	3,526	(804)	(23)%
Northern Powder River Basin	1,301	1,054	247	23 %
Gulf Coast	361	281	80	28 %
Total coal royalty production	11,395	13,370	(1,975)	(15)%
Average coal royalty revenue per ton				
Appalachia				
Northern	$0.50	$0.90	$(0.40)	(44)%
Central	3.76	4.69	(0.93)	(20)%
Southern	4.18	5.04	(0.86)	(17)%
Total Appalachia	3.10	3.81	(0.71)	(19)%
Illinois Basin	4.05	4.08	(0.03)	(1)%
Northern Powder River Basin	2.80	2.91	(0.11)	(4)%
Gulf Coast	4.26	3.40	0.86	25 %
Combined average coal royalty revenue per ton	$3.33	$3.80	$(0.47)	(12)%
Coal royalty revenues				
Appalachia				
Northern	$763	$1,844	$(1,081)	(59)%
Central	17,440	25,470	(8,030)	(32)%
Southern	3,561	5,130	(1,569)	(31)%
Total Appalachia	21,764	32,444	(10,680)	(33)%
Illinois Basin	11,015	14,403	(3,388)	(24)%
Northern Powder River Basin	3,641	3,069	572	19 %
Gulf Coast	1,537	954	583	61 %
Total coal royalty revenue	$37,957	$50,870	$(12,913)	(25)%
Other coal related revenues				
Override revenue	$433	$771	$(338)	(44)%
Transportation and processing fees	5,338	5,589	(251)	(4)%
Minimums recognized as revenue	3,234	1,396	1,838	132 %
Coal reserve swap	—	5,690	(5,690)	N/A
DOH property sale	1,641	—	1,641	100 %
Lease assignment fee	6,000	—	6,000	100 %
Wheelage	401	877	(476)	(54)%
Total other coal related revenues	$17,047	$14,323	$2,724	19 %
	$55,004	$65,193	$(10,189)	(16)%

Total coal related revenues and coal related revenues—affiliates

Coal prices continue to be depressed, which has negatively affected our coal related revenues. Further declines or a continued low price environment could have an additional adverse effect on our coal related revenues. Coal production, as well as coal revenues, were down in each of the three Appalachian regions and in the Illinois Basin, while we saw increases in coal production and coal royalty revenues in the Northern Powder River Basin and the Gulf Coast for the three months ended September 30, 2015 as compared to the same period in 2014. The average coal royalty revenue per ton decreased throughout all of our regions, with the exception of the Gulf Coast during the three months ended September 30, 2015 when compared to the same quarter last year.

Other coal related revenues for the three months ended September 30, 2015 increased $2.7 million, or 19% compared to the same period in 2014. This increase was primarily a result of a $6.0 million lease assignment fee, $1.8 million increased minimums recognized as revenue primarily due to the recoupment period under our lease relating to Foresight Energy's Macoupin mine expiring in 2015 and a $1.6 million public roadway condemnation payment. Offsetting this increase, was a $5.7 million decline in coal reserve swap income relative to the third quarter of 2014.

Aggregates Related Revenues and Industrial Minerals Other Income

Total aggregates related revenues and total industrial minerals other income represented approximately 44% and 14% of our total revenues and other income for the three months ended September 30, 2015 and 2014, respectively. The table below presents the major categories of our aggregates related revenues and industrial minerals other income:

	Three Months Ended September 30,		Increase (Decrease)	Percentage Change	
	2015	2014			
	(In thousands, except percent and ton data) (Unaudited)				
VantaCore					
Tonnage sold	2,126	N/A	N/A	N/A	
Revenues	$39,208	N/A	N/A	N/A	
Operating expenses	$31,107	N/A	N/A	N/A	
Aggregates royalty related revenues	$3,118	$2,655	$463	17	%
Total aggregates related revenues	$42,326	$2,655	$39,671	1,494	%
Industrial minerals other income and cash distributions					
Equity in earnings of unconsolidated investment	$12,617	$9,685	$2,932	30	%
Cash distributions from equity earnings in unconsolidated investment	$12,740	$10,290	$2,450	24	%

VantaCore

VantaCore operates four hard rock quarries, one underground limestone mine, six sand and gravel plants, two asphalt plants and a marine terminal. We recognized $39.2 million of aggregates related revenues from VantaCore's operations in the three months ended September 30, 2015.

Industrial Minerals Other Income and Cash Distributions

For the three months ended September 30, 2015, equity in the earnings of the Ciner Wyoming trona mining and soda ash production business was $12.6 million, and we received $12.7 million in cash distributions from Ciner Wyoming. For the three months ended September 30, 2014, we recorded equity in the earnings of Ciner Wyoming of $9.7 million and received $10.3 million in cash distributions.

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Oil and Natural Gas Revenues

Total oil and gas revenues comprised approximately 10% of our total revenues and other income for each of the three months ended September 30, 2015 and 2014. The table below presents oil and gas production and revenues derived from our major oil and gas producing regions and the significant categories of oil and gas related revenues:

	Three Months Ended September 30,		Increase (Decrease)	Percentage Change
	2015	2014		
	(in thousands, except per unit data) (Unaudited)			
Williston Basin non-operated working interests:				
Production volumes:				
Oil (MBbl)	276	77	199	258 %
Natural gas (Mcf)	192	90	102	113 %
NGL (MBbl)	33	8	25	313 %
Total production (MBoe)	341	100	241	241 %
Average sales price per unit:				
Oil (Bbl)	$39.24	$84.65	$(45.41)	(54)%
Natural gas (Mcf)	2.62	5.11	(2.49)	(49)%
NGL (Bbl)	3.48	41.00	(37.52)	(92)%
Revenues:				
Oil	$10,829	$6,518	$4,311	66 %
Natural gas	503	460	43	9 %
NGL	115	328	(213)	(65)%
Total revenues	$11,447	$7,306	$4,141	57 %
Royalty and overriding royalty revenues	$969	$2,295	$(1,326)	(58)%
Total oil and gas revenues	$12,416	$9,601	$2,815	29 %

Our oil and gas revenues are highly dependent on commodity prices, which can fluctuate significantly. Oil and gas revenues decreased $2.8 million, or 29%, for the three months ended September 30, 2015 when compared to the same period ended for 2014. The decrease in revenues is primarily due to lower oil and natural gas prices, partially offset by higher oil and natural gas production volumes resulting from our fourth quarter 2014 Sanish Field acquisition.

Operating Expenses

Asset impairments

As discussed under “—Executive Overview" above, we recorded the following asset impairments during the three months ended September 30, 2015 (in thousands):

	Three Months Ended September 30,	
Impaired Mineral rights	2015	2014
	(Unaudited)	
Oil and gas properties	$335,662	$—
Coal properties	247,815	—
Aggregates properties	43,361	—
Total	$626,838	$—

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It is reasonably possible that our estimate of discounted future net cash flows could change in the near term. If conditions in coal markets continue to deteriorate, it is likely that additional non-cash write-downs of properties would occur in the future. Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from our oil and natural gas reserves could continue to change in the near term. If oil and natural gas prices decline from the prices used in our impairment analysis, it is likely that additional non-cash write-downs of oil and gas properties will occur in the future. If future capital expenditures out-pace future discounted net cash flows in our reserve calculations or if we have significant declines in our oil and natural gas reserve volumes, our estimate of discounted future net cash flows from oil and natural gas reserves, non-cash write-downs of our oil and natural gas properties would occur in the future. In order to test the sensitivity of the fair value of our oil and gas properties to changes in oil and gas prices, management modeled a 10% change in the forward price curve across the full term of expected future cash flows from our oil and gas properties. This 10% change in oil and gas prices resulted in zero additional non-cash write-downs and an immaterial decline in our oil and natural gas reserve volumes.

Depreciation, depletion and amortization

Depreciation, depletion and amortization increased $8.0 million, or 43%, for the three months ended September 30, 2015 when compared to the same period ended for 2014, primarily as a result of the VantaCore and Sanish Field assets acquired during the fourth quarter of 2014.

Interest Expense

Interest expense increased $4.8 million, or 26%, for the three months ended September 30, 2015 when compared to the same period ended for 2014, primarily as a result of additional debt incurred to complete acquisitions in the fourth quarter of 2014.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Adjusted EBITDA (Non-GAAP Financial Measure)

Adjusted EBITDA increased $7.4 million, or 3%, from $214.5 million in the nine months ended September 30, 2014 to$221.9 million in the nine months ended September 30, 2015. This increase in Adjusted EBITDA is mainly related to the inclusion of VantaCore and the Sanish Field in our operating results in 2015. This increase was partially offset by decreased coal royalty revenues in 2015 as compared to 2014.
Adjusted EBITDA is a non-GAAP financial measure. For an explanation of Adjusted EBITDA, see “—Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014—Adjusted EBITDA (Non-GAAP Financial Measure).” The following table (in thousands) reconciles net income to Adjusted EBITDA for the nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30,	
	2015	2014
	(Unaudited)	
Net income (loss)	$(549,934)	$100,185
Less: equity earnings in unconsolidated investment	(36,739)	(28,865)
Less: gain on reserve swap	(9,290)	(5,690)
Add: asset impairments	630,641	5,624
Add: depreciation, depletion and amortization	82,676	49,618
Add: distributions from equity earnings in unconsolidated investment	34,545	35,858
Add: interest expense, gross	69,997	57,759

Adjusted EBITDA	$221,896	$214,489

Adjusted EBITDA presented in the table above differs from the EBITDDA definitions contained in Opco's debt agreements. 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 Note 7. "Debt and Debt—Affiliate" in the consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for a description of Opco's debt agreements.

Distributable Cash Flow (Non-GAAP Financial Measure)

Distributable cash flow is a non-GAAP financial measure. For an explanation of distributable cash flow, see "—Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014—Distributable Cash Flow (Non-GAAP Financial Measure)." The following table (in thousands) reconciles net cash provided by operating activities to distributable cash flow for the nine months ended September 30, 2015 and 2014.

	Nine Months Ended September 30,	
	2015	2014
	(Unaudited)	
Net cash provided by operating activities	$161,350	$157,096
Add: proceeds from sale of plant and equipment and other	11,006	5
Add: proceeds from sale of mineral rights	6,941	—
Add: return on long-term contract receivables—affiliate	2,121	910
Add: return on unconsolidated equity investments	—	3,633
Less: maintenance capital expenditures (1)	(20,869)	—
Less: distributions to non-controlling interest	(2,744)	(974)
Distributable cash flow	$157,805	$160,670

(1) Maintenance capital expenditures primarily consist of costs to maintain the long-term productive capacity of our oil and gas non-operating working interest business and VantaCore.

Diversified Natural Resource Revenues and Other Income

The following table shows our diversified sources of revenues and other income in the nine months ended September 30, 2015 and 2014:

	Coal Related Revenues (Including Affiliates)		Aggregates Related Revenues		Industrial Minerals Other Income (Ciner Wyoming)		Oil and Gas Related Revenues		Other Revenues		Total
	(In thousands except for percentages) (Unaudited)										
2015											
Revenues	$165,390		$114,158		$ 36,739		$42,485		$14,014		$372,786
Percentage of total	44	%	31	%	10	%	11	%	4	%	
2014											
Revenues	$172,927		$9,614		$ 28,865		$37,481		$13,592		$262,479
Percentage of total	66	%	4	%	11	%	14	%	5	%	

Coal Related Revenues (including affiliates)

Total coal related revenues comprised approximately 44% and 66% of our total revenues and other income for the nine months ended September 30, 2015 and 2014, respectively. The table below presents coal royalty production and revenues derived from our major coal producing regions and the significant categories of other coal related revenues:

	Nine Months Ended September 30,		Increase (Decrease)	Percentage Change
	2015	2014		
	(In thousands, except percent and per ton data) (Unaudited)			
Coal royalty production (tons)				
Appalachia				
Northern	7,581	6,537	1,044	16 %
Central	13,402	15,096	(1,694)	(11)%
Southern	3,000	2,950	50	2 %
Total Appalachia	23,983	24,583	(600)	(2)%
Illinois Basin	8,265	10,064	(1,799)	(18)%
Northern Powder River Basin	3,497	2,106	1,391	66 %
Gulf Coast	778	720	58	8 %
Total coal royalty production	36,523	37,473	(950)	(3)%
Average coal royalty revenue per ton				
Appalachia				
Northern	$0.28	$0.91	$(0.63)	(69)%
Central	3.93	4.59	(0.66)	(14)%
Southern	4.55	5.24	(0.69)	(13)%
Total Appalachia	2.85	3.69	(0.84)	(23)%
Illinois Basin	4.00	4.07	(0.07)	(2)%
Northern Powder River Basin	2.64	2.87	(0.23)	(8)%
Gulf Coast	3.85	3.43	0.42	12 %
Combined average coal royalty revenue per ton	$3.11	$3.74	$(0.63)	(17)%
Coal royalty revenues				
Appalachia				
Northern	$2,105	$5,941	$(3,836)	(65)%
Central	52,616	69,289	(16,673)	(24)%
Southern	13,646	15,469	(1,823)	(12)%
Total Appalachia	68,367	90,699	(22,332)	(25)%
Illinois Basin	33,020	40,956	(7,936)	(19)%
Northern Powder River Basin	9,219	6,041	3,178	53 %
Gulf Coast	2,996	2,473	523	21 %
Total coal royalty revenue	$113,602	$140,169	$(26,567)	(19)%
Other coal related revenues				
Override revenue	$2,195	$3,516	$(1,321)	(38)%
Transportation and processing fees	16,400	16,682	(282)	(2)%
Minimums recognized as revenue	12,480	4,204	8,276	197 %
Coal reserve swap	9,290	5,690	3,600	63 %
DOH Property Sale	3,306	—	3,306	100 %
Lease assignment fee	6,000	—	6,000	100 %
Wheelage	2,117	2,666	(549)	(21)%
Total other coal related revenues	$51,788	$32,758	$19,030	58 %
	$165,390	$172,927	$(7,537)	(4)%

Total coal related revenues and coal related revenues—affiliates

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During the nine months ended September 30, 2015 as compared to the same period in 2014, total coal production and total coal royalty revenues was down in Appalachia and the Illinois Basin, while we saw a significant increase in the Northern Powder River Basin and a slight increase in the Gulf Coast. All Appalachian regions saw a decrease in coal royalty revenues for the period with coal royalty revenues in Northern Appalachia down 65% despite a 16% increase in production from that area. We saw a decrease in the average coal revenue per ton throughout all of our regions, with the exception of the Gulf Coast, for the nine months ended September 30, 2015 when compared to the nine months ended September 30, 2014.

Other coal related revenues for the nine months ended September 30, 2015 increased $19.0 million, or 58%, compared to the same period in 2014. This increase was primarily a result of $8.3 million increased minimums recognized as revenue primarily due to the recoupment period under our lease relating to Foresight Energy's Macoupin mine expiring in 2015, a $6.0 million lease assignment fee, $3.6 million increased gain on coal reserve swaps and $3.3 million public roadway condemnation payments.

Aggregates Related Revenues and Industrial Minerals Other Income

Total aggregates related revenues and total industrial minerals other income represented approximately 41% and 15% of our total revenues and other income for the nine months ended September 30, 2015 and 2014, respectively. The table below presents the major categories of our aggregates related revenues and industrial minerals other income:

	Nine Months Ended September 30,		Increase (Decrease)	Percentage Change
	2015	2014		
	(In thousands, except percent and ton data)		(Unaudited)	
VantaCore				
Tonnage sold	5,652	N/A	N/A	N/A
Revenues	$106,606	N/A	N/A	N/A
Operating expenses	$86,314	N/A	N/A	N/A
Aggregates royalty revenues	$7,552	$9,614	$(2,062)	(21)%
Total aggregates related revenues	$114,158	$9,614	$104,544	1,087 %
Industrial minerals other income and cash distributions				
Equity in earnings of unconsolidated investment	$36,739	$28,865	$7,874	27 %
Cash distributions from equity earnings in unconsolidated investment	$34,545	$35,858	$(1,313)	(4)%

VantaCore

We recognized $106.6 million of aggregates related revenues from VantaCore's operations in the nine months ended September 30, 2015.

Aggregates Royalty Revenues

Aggregates royalty revenues decreased $2.1 million, or 21%, in the nine months ended September 30, 2015 as compared to the same period of 2014. This decrease is primarily due to a lessee moving from property where we collect a 15% royalty to property where we collect a 1% overriding royalty.

Industrial Minerals Other Income and Cash Distributions

For the nine months ended September 30, 2015, equity in the earnings of our investment in the Ciner Wyoming trona mining and soda ash production business was $36.7 million, and we received $34.5 million in cash distributions from Ciner Wyoming. For the nine months ended September 30, 2014, we recorded equity in the earnings of Ciner Wyoming of $28.9 million and received $35.9 million in cash distributions.

Oil and Natural Gas Revenues

Total oil and gas revenues comprised approximately 11% and 14% of our total revenues and other income for the nine months ended September 30, 2015 and 2014, respectively. The table below presents oil and gas production and revenues derived from our major oil and gas producing regions and the significant categories of oil and gas related revenues:

	Nine Months Ended September 30,		Increase (Decrease)	Percentage Change
	2015	2014		
	(Dollars in thousands, except per unit data) (Unaudited)			
Williston Basin non-operated working interests:				
Production volumes:				
Oil (MBbl)	849	284	565	199 %
Natural gas (Mcf)	601	202	399	198 %
NGL (MBbl)	109	20	89	445 %
Total production (MBoe)	1,058	338	720	213 %
Average sales price per unit:				
Oil (Bbl)	$42.37	$92.82	$(50.45)	(54)%
Natural gas (Mcf)	2.56	6.45	(3.89)	(60)%
NGL (Bbl)	9.57	45.55	(35.98)	(79)%
Revenues:				
Oil	$35,976	$26,360	$9,616	36 %
Natural gas	1,540	1,303	237	18 %
NGL	1,043	911	132	14 %
Non-production revenue	450	—	450	100 %
Total revenues	$39,009	$28,574	$10,435	37 %
Royalty and overriding royalty revenues	$3,476	$8,907	$(5,431)	(61)%
Total oil and gas revenues	$42,485	$37,481	$5,004	13 %

Our oil and gas related revenues are highly dependent on commodity prices, which can fluctuate significantly. Oil and gas revenues increased $5.0 million, or 13%, for the nine months ended September 30, 2015 when compared to the same period ended for 2014. The increase in revenues is due to increased production resulting from the fourth quarter 2014 Sanish Field acquisition that was partially offset by lower oil and gas prices in 2015 as compared to 2014.

Operating Expenses

Asset impairments

We recorded the following asset impairments (in thousands) during the nine months ended September 30, 2015 and 2014, substantially all of which was recorded in the third quarter of 2015 as discussed under "—Executive Overview" above:

	Nine Months Ended September 30,	
Impaired Assets	2015	2014
	(Unaudited)	
Mineral Rights		
Oil and gas properties	$335,662	$—
Coal properties	249,362	—
Aggregates properties	43,361	—
Plant and Equipment		
Aggregates properties	2,256	—
Intangible Assets		
Aggregates properties	—	5,624
Total	$630,641	$5,624

Depreciation, depletion and amortization

Depreciation, depletion and amortization increased $33.1 million, or 67%, for the nine months ended September 30, 2015 when compared to the same period ended for 2014, primarily as a result of the VantaCore and Sanish Field acquisitions during the fourth quarter of 2014. This increase was partially offset by a $3.8 million credit to adjust the impact of depletion expense recorded in prior periods as discussed in Note 1 to our consolidated financial statements incorporated herein by reference.

Interest Expense

Interest expense increased $12.2 million, or 21%, for the nine months ended September 30, 2015 when compared to the same period ended for 2014, primarily as a result of additional debt incurred to complete acquisitions in the fourth quarter of 2014.

Liquidity and Capital Resources

Overview

At September 30, 2015, our liquidity consisted of $61.2 million in cash and $15.0 million in combined borrowing capacity under our revolving credit facilities. During the nine months ended September 30, 2015, we reduced our debt by a net amount of $51.2 million. Opco's $300.0 million revolving credit facility matures in October 2017, and as of September 30, 2015, we had $290.0 million outstanding thereunder. We borrowed $75.0 million under Opco's revolving credit facility in September 2015 in order to repay Opco's term loan in full. In October 2015, the borrowing base under the NRP Oil and Gas revolving credit facility was redetermined to $88.0 million, and we repaid $15.0 million under that facility, reducing our outstanding borrowings under that facility to $85.0 million. As of the date of this report, the combined borrowing capacity under our revolving credit facilities is $13.0 million.

While we believe we have sufficient liquidity to meet our current financial needs, we have significant debt service requirements, including $80.8 million in principal payments on Opco's senior notes each year through 2018, and our operating results continue to be impacted by the adverse conditions in the commodity markets. In April 2015, we announced a long-term plan to strengthen our balance sheet, reduce debt and enhance liquidity in order to reposition the partnership for future growth. As part of that plan, we reduced our cash distributions with respect to the first and second quarters of 2015 to $0.09 per common unit, a 75% decrease from the distribution paid with respect to fourth quarter of 2014. In October 2015, the Board declared a distribution of $0.045 per common unit with respect to the third quarter of 2015, representing an additional 50% reduction in the distribution paid with respect to the second quarter of 2015. The cash savings resulting from the distribution reductions are being used primarily to repay debt. In addition, we have announced our intention to commence processes to sell certain assets in furtherance of achieving the goals set out in our strategic plan. We have also taken steps to reduce general and administrative and other overhead costs in connection with these efforts. If we are unable to complete any asset sales and conditions in the coal and oil and gas

markets continue to deteriorate, our liquidity and our ability to comply with the financial and other restrictive covenants contained in our debt agreements will be adversely affected.

We also have $425.0 million principal amount of 9.125% senior notes issued by NRP and NRP Finance, as co-issuers, that mature in 2018. While we believe we will be able to refinance these notes, we may not be able to do so on terms acceptable to us, if at all. Our ability to comply with the financial and other restrictive covenants in our debt agreements will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. In addition, our ability to refinance our debt may depend in part or our ability to access the debt or equity capital markets, which are challenging in the current market environment.

Generally, we satisfy our working capital requirements with cash generated from operations. Our current liabilities exceeded our current assets by approximately $16.8 million as of September 30, 2015, primarily due to $80.8 million in principal payments on Opco’s senior notes due over the next year. Excluding these principal payments, our current assets exceeded our current liabilities by approximately $64.0 million as of September 30, 2015.

Capital Expenditures

Our capital expenditures, other than for acquisitions, have historically been minimal. However, as a result of our Sanish Field oil and gas and VantaCore aggregates acquisitions in the fourth quarter of 2014, our operating capital expenditures have been higher in 2015 and will continue to be higher than historical levels. A portion of the capital expenditures associated with both our oil and gas working interest business and VantaCore are maintenance capital expenditures, which are capital expenditures made to maintain the long-term production capacity of those businesses. We deduct maintenance capital expenditures when calculating distributable cash flow and expect that the majority of our 2015 maintenance capital expenditures were incurred during the first nine months of the year. Total capital expenditures for NRP Oil and Gas for the three and nine months ended September 30, 2015 were $6.8 million and $35.5 million, respectively. We continue to monitor the development programs of the operators of these properties and manage the capital expenditures associated with those properties by only participating in wells that are expected to provide acceptable economic returns. VantaCore’s capital expenditures for the three and nine months ended September 30, 2015 were $1.9 million and $6.8 million, respectively.

Cash Flows

Net cash provided by operating activities for the nine months ended September 30, 2015 and 2014 was $161.4 million and $157.1 million, respectively. The majority of our cash provided by operations is generated from coal royalty revenues, our equity interest in Ciner Wyoming and oil and gas revenues.
Net cash used in investing activities for the nine months ended September 30, 2015 and 2014 was $24.5 million and $9.7 million, respectively.
Net cash used in financing activities for the nine months ended September 30, 2015 and 2014 was $125.8 million and $161.8 million, respectively. During the nine months ended September 30, 2015 and 2014, we had proceeds from loans of $100.0 million and $2.0 million, respectively. During the nine months ended September 30, 2015 and 2014, these proceeds were offset by repayment of debt of $151.2 million and $69.2 million, respectively. Also during the nine months ended September 30, 2015 and 2014, we paid cash distributions to our unitholders of $66.1 million and $118.4 million, respectively.

Capital Resources and Obligations

Indebtedness

As of September 30, 2015 and December 31, 2014, we had the following indebtedness:

	September 30, 2015 (Unaudited)	December 31, 2014
Current portion of long-term debt, net	$80,983	$80,983
Long-term debt and debt—affiliate, net	1,343,631	1,394,240
Total debt and debt—affiliate, net	$1,424,614	$1,475,223

We were and continue to be in compliance with the terms of the financial covenants contained in our debt agreements. For additional information regarding our debt and the agreements governing our debt, including the covenants contained therein, see

Note 7. “Debt and Debt—Affiliate” to the consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q.

Anadarko Contingent Consideration Payment Claim

The purchase agreement for the acquisition of our interest in Ciner Wyoming requires us to pay additional contingent consideration to Anadarko to the extent certain performance criteria described in the purchase agreement are met at Ciner Wyoming in any of the years 2013, 2014 or 2015. We paid $0.5 million and $3.8 million of consideration in the first quarter of 2014 and 2015, respectively, in satisfaction of our obligations under this agreement with respect to 2013 and 2014. As of September 30, 2015, we estimate, and have recorded $8.8 million as the amount that will be payable in the first quarter of 2016 with respect to 2015. We have no obligation to pay contingent consideration with respect to any period after 2015.

In March 2014, Anadarko gave us written notice that it believed certain reorganization transactions conducted in 2013 within the OCI organization triggered an acceleration of our obligation to pay the additional contingent consideration in full and demanded immediate payment of such amount. We disagreed with Anadarko’s position in a written response provided to Anadarko in April 2014. In April 2015, Anadarko sent a written request for additional information regarding the OCI reorganization and indicated that they are still considering this claim against us. We do not believe the reorganization transactions triggered an obligation to pay the additional contingent consideration. We responded in writing in May 2015, and we will continue to engage in discussions with Anadarko to resolve the issue if necessary. However, if Anadarko were to pursue and prevail on such a claim, we would be required to pay an amount to Anadarko in excess of the amounts already paid, together with the $8.8 million accrual described above, up to the maximum amount of the additional contingent consideration, minus a deductible. Under the purchase agreement, the maximum cumulative amount of additional contingent consideration is an amount equal to the net present value of $50 million. Any additional amount paid by us would be considered to be additional acquisition consideration and added to Equity and other unconsolidated investments and would reduce our liquidity.

Shelf Registration Statement

In September 2015, we filed a registration statement on Form S-3 with the SEC that is available for registered offerings of common units.

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

The information set forth under Note 9 to the consolidated financial statements under the caption “Related Party Transactions” is incorporated herein by reference.

Summary of Critical Accounting Estimates

The preparation of consolidated financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make certain estimates and assumptions that affect the amounts reported in the consolidated financial statements and the accompanying notes. There have been no significant changes to our critical accounting estimates from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014.

Recent Accounting Standards

The information set forth under Note 1 to the consolidated financial statements under the caption “Basis of Presentation” is incorporated herein by reference.

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. We estimate that over 65% of our coal is currently 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.

We have market risk related to the prices for oil and natural gas, NGLs and condensate. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Partnership's oil and gas properties may be required if commodity prices experience a significant decline.

We have market risk related to prices for our aggregates products. Aggregates prices are primarily driven by economic conditions in the local markets in which the products are sold.

The market price of soda ash directly affects the profitability of Ciner Wyoming's operations. If the market price for soda ash declines, Ciner 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.

Interest Rate Risk

Our exposure to changes in interest rates results from our borrowings under our revolving credit facility and term loan, which are subject to variable interest rates based upon LIBOR. At September 30, 2015, we had $390.0 million in variable interest rate debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $3.9 million, assuming the same principal amount remained outstanding during the year.

Item 4. Controls and Procedures

Evaluation of Disclosure 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.

Changes in the Partnership's Internal Control Over Financial Reporting

There were no changes in the Partnership's internal control over financial reporting during the third quarter of 2015 that materially affected, or were reasonably likely to materially affect, the Partnership's internal control over financial reporting. The Partnership continues to integrate certain processes and related internal control over financial reporting as a result of the acquisition of VantaCore Partners LLC. The Partnership will continue to assess the effectiveness of its internal control over financial reporting as integration activities continue.

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. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes these claims will not have a material adverse effect on our financial position, liquidity, or operations.

For more information concerning certain legal proceedings involving the Partnership, see Note 13. “Commitments and Contingencies” to the consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q, which is incorporated herein by reference.

Item 1A. Risk Factors

During the period covered by this report, other than as set forth below, there were no material changes from the risk factors previously disclosed in Natural Resource Partners L.P.’s Annual Report on Form 10-K for the year ended December 31, 2014.

Foresight Energy’s Deer Run mine is currently idled as a result of elevated carbon monoxide levels at the mine. If the mine remains idled for an extended period or does not resume operations, our financial condition and results of operations could be adversely affected.

In late March 2015, elevated carbon monoxide readings were detected at Foresight Energy’s Deer Run mine, which we also refer to as our Hillsboro property, and coal production at the mine was idled. Mining operations resumed at the mine in late July under a plan approved by the Federal Mine Safety and Health Administration (“MSHA”), but the mine was idled in early August due again to elevated carbon monoxide levels. In July 2015, we received a notice from Foresight Energy declaring a force majeure event at the mine as a result of the elevated carbon monoxide levels. While we are disputing Foresight Energy’s claim, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us minimum deficiency payments of $7.5 million per quarter, or $30.0 million per year. Foresight Energy's failure to make the deficiency payment with respect to the second and third quarters resulted in a $9.2 million cash impact to us. We do not currently have an estimate as to when the mine will resume coal production. If the mine remains idled for an extended period our financial condition could be adversely affected.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

The information concerning mine safety violations or other regulatory matters required by SEC regulations is included in Exhibit 95.1 to this Quarterly Report on Form 10-Q.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No.		Description
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).
2.2	—	Agreement and Plan of Merger, dated as of August 18, 2014, by and among VantaCore Partners LP, VantaCore LLC, the Holders named therein, Natural Resource Partners L.P., NRP (Operating) LLC and Rubble Merger Sub, LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on August 20, 2014).
2.3	—	Interest Purchase Agreement, by and among NRP Oil and Gas LLC, Kaiser-Whiting, LLC and the Owners of Kaiser-Whiting, LLC dated as of October 5, 2014 (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on October 6, 2014).
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).
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.
95.1*	—	Mine Safety Disclosure.
101.INS*	—	XBRL Instance Document
101.SCH*	—	XBRL Taxonomy Extension Schema Document
101.CAL*	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	—	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	—	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed or, in the case of Exhibits 32.1 and 32.2, furnished herewith.

SIGNATURES

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

NATURAL RESOURCE PARTNERS L.P.
By: NRP (GP) LP, its general partner
By: GP NATURAL RESOURCE PARTNERS LLC, its general partner

Date: November 5, 2015

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

Date: November 5, 2015

By: /s/ Craig Nunez
Craig Nunez,
Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: November 5, 2015

By: /s/ Chris Zolas
Chris Zolas
Chief Accounting Officer
(Principal Accounting Officer)