NATURAL RESOURCE PARTNERS LP
Form 10-K
February 28, 2014
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2013 or

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

For the transition period from to

Commission file number: 1-31465

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 Number)*
601 Jefferson, Suite 3600 Houston, Texas	**77002**
(Address of principal executive offices)	*(Zip Code)*

(713) 751-7507

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units representing limited partnership interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

x Large Accelerated Filer ¨ Accelerated Filer ¨ Non-accelerated Filer ¨ Smaller Reporting Company

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they were affiliates of the registrant) was approximately $1.5 billion on June 30, 2013 based on a price of $20.57 per unit, which was the closing price of the Common Units as reported on the daily composite list for transactions on the New York Stock Exchange on that date.

As of February 28, 2014, there were 109,812,408 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE.

None.

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Forward-Looking Statements

Statements included in this Annual Report on Form 10-K 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, hydrocarbons, aggregates and industrial minerals;
- estimated revenues, expenses and results of operations;
- the amount, nature and timing of capital expenditures;
- our ability to make acquisitions;
- our liquidity and access to capital;
- projected production levels by our lessees;
- OCI Wyoming, L.P. 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 for important factors that could cause our actual results of operations or our actual financial condition to differ.

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PART I

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

Item 1. *Business*

We are a limited partnership formed in April 2002, and we completed our initial public offering in October 2002. We engage principally in the business of owning, managing and leasing mineral properties in the United States. We own coal reserves in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. As of December 31, 2013, we owned or controlled approximately 2.3 billion tons of proven and probable coal reserves. We do not operate any mines, but lease our reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell our reserves in exchange for royalty payments. We also own and manage infrastructure assets that generate additional revenues for our company, particularly in the Illinois Basin.

We have made a concerted effort to diversify our business in recent years. In 2013, we spent over $365 million to acquire interests in non-coal-related operating businesses. In January 2013, we acquired a non-controlling equity interest in OCI Wyoming, L.P., an operator of a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming for $292.5 million. We also completed two acquisitions of non-operated working interests in oil and gas operations in the Williston Basin of North Dakota and Montana for an aggregate purchase price of $72 million. In addition, we own various interests in oil and gas properties that are located in other areas, including the Appalachian Basin, Louisiana and Oklahoma, and we own approximately 500 million tons of aggregate reserves located in a number of states across the country.

For the year ended December 31, 2013, we recognized approximately $145.5 million (40.6%) of our revenues and other income from sources other than coal royalties, which primarily consisted of equity income from our investment in OCI Wyoming, oil and gas revenues, aggregates royalties, overriding royalties (which include coal and aggregates overrides), minimums recognized as revenue, and processing and transportation fees. The revenues that we recognize from minimums and processing/transportation are largely derived from coal-related businesses.

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

Oil and gas royalty revenues include production payments as well as bonus payments. Oil and gas royalty revenues are recognized on the basis of hydrocarbons sold by lessees and the corresponding revenues from those sales. Generally, the lessees make payments based on a percentage of the selling price. Some leases are subject to minimum annual payments or delay rentals. Revenues related to our non-operated working interests in oil and gas assets are recognized on the basis of our net revenue interests in hydrocarbons produced. We also incur capital expenditures and operating expenses associated with the non-operated working interests in oil and gas assets.

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Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through two wholly owned operating companies, NRP (Operating) LLC and NRP Oil and Gas LLC. NRP (GP) LP, our general partner, has sole responsibility for conducting our business and for managing our operations. Because our general partner is a limited partnership, its general partner, GP Natural Resource Partners LLC, conducts its business and operations, and the Board of Directors and officers of GP Natural Resource Partners LLC makes decisions on our behalf. Robertson Coal Management LLC, a limited liability company wholly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. Subject to the Investor Rights Agreement with Adena Minerals, LLC, Mr. Robertson is entitled to nominate ten directors, five of whom must be independent directors, to the Board of Directors of GP Natural Resource Partners LLC. Mr. Robertson has delegated the right to nominate two of the directors, one of whom must be independent, to Adena Minerals.

The senior executives and other officers who manage NRP are employees of Western Pocahontas Properties Limited Partnership and Quintana Minerals Corporation, companies controlled by Mr. Robertson, and they allocate varying percentages of their time to managing our operations. Neither our general partner, GP Natural Resource Partners LLC, nor any of their affiliates receive any management fee or other compensation in connection with the management of our business, but they are entitled to be reimbursed for all direct and indirect expenses incurred on our behalf.

Our operations headquarters is located at 5260 Irwin Road, Huntington, West Virginia 25705 and the telephone number is (304) 522-5757. Our principal executive office is located at 601 Jefferson Street, Suite 3600, Houston, Texas 77002 and our phone number is (713) 751-7507.

Royalty Business

Royalty businesses principally own and manage mineral reserves. As an owner of mineral reserves, we typically are not responsible for operations on our properties, but instead enter into leases with operators granting them the right to mine and sell reserves from our property in exchange for a royalty payment. A typical lease has a five- to ten-year base term, with the lessee having an option to extend the lease for additional terms. Leases may include the right to renegotiate rents and royalties for the extended term.

Under our standard lease, lessees calculate royalty payments due us and are required to report tons of coal or aggregates removed as well as the sales prices of the extracted minerals. Therefore, to a great extent, amounts reported as royalty revenue are based upon the reports of our lessees. We periodically audit this information by examining certain records and internal reports of our lessees, and we perform periodic mine inspections to verify that the information that our lessees have submitted to us is accurate. Our audit and inspection processes are designed to identify material variances from lease terms as well as differences between the information reported to us and the actual results from each property. Our audits and inspections, however, are in periods subsequent to when the revenue is reported and any adjustment identified by these processes might be in a reporting period different from when the royalty revenue was initially recorded.

Our royalty revenues are affected by changes in long-term and spot commodity prices, production volumes, unseasonal weather, lessees supply contracts and the royalty rates in our leases. The prevailing prices for coal and oil and gas depend on a number of factors, including the supply-demand relationship, the price and availability of alternative fuels, global economic conditions and governmental regulations. The prevailing price for aggregates generally depends on local and in some cases, global, economic conditions. In addition to their royalty obligation, our lessees are often subject to pre-established minimum monthly, quarterly or annual payments. These minimum rentals reflect amounts we are entitled to receive even if no mining activity occurred during the period. Minimum rentals are usually credited against future royalties that are earned as minerals are produced. We do not typically receive minimum royalties with respect to our oil and gas properties, although we do have some leases with minimum annual payments or delay rental provisions, but do typically receive bonus payments at the time of execution of the lease.

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Because we do not operate any mines, our royalty business does not bear ordinary operating costs and has limited direct exposure to environmental, permitting and labor risks. As operators, our lessees are subject to environmental laws, permitting requirements and other regulations adopted by various governmental authorities. In addition, the lessees generally bear all labor-related risks, including retiree health care legacy costs, black lung benefits and workers compensation costs associated with operating the mines on our coal and aggregate properties. We typically pay property taxes on our properties, which are then reimbursed by the lessee pursuant to the terms of the lease.

Acquisitions

We are a growth-oriented company and have completed a number of acquisitions. For a discussion of our recent acquisitions, see Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Acquisitions.

Coal Royalty Revenues, Reserves and Production

The following summary table sets forth coal royalty revenues and average coal royalty revenue per ton from the properties that we owned or controlled for the years ending December 31, 2013, 2012 and 2011. Coal royalty revenues were generated from the properties in each of the areas as follows:

	Coal Royalty Revenues For the Years Ended December 31, (In thousands)			Average Coal Royalty Revenue Per Ton For the Years Ended December 31, ($ per ton)		
	2013	2012	2011	2013	2012	2011
Area						
Appalachia						
Northern	$ 14,643	$ 15,768	$ 20,578	$ 1.27	$ 1.50	$ 3.92
Central	105,004	156,390	196,789	$ 5.05	$ 5.99	$ 6.66
Southern	26,156	29,325	11,717	$ 6.30	$ 7.89	$ 6.91
Total Appalachia	145,803	201,483	229,084	$ 4.00	$ 5.00	$ 6.28
Illinois Basin	56,001	49,538	41,324	$ 4.28	$ 4.38	$ 4.38
Northern Powder River Basin	7,569	8,501	7,658	$ 2.72	$ 3.58	$ 2.86
Gulf Coast	3,290	1,212	1,155	$ 3.39	$ 2.60	$ 2.21
Total	$ 212,663	$ 260,734	$ 279,221	$ 3.99	$ 4.79	$ 5.68

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The following summary table sets forth coal production data and reserve information for the properties that we owned or controlled for the years ending December 31, 2013, 2012 and 2011. All of the reserves reported below are recoverable reserves as determined by the SEC s Industry Guide 7. In excess of 90% of the reserves listed below are currently leased to third parties. Coal production data and reserve information for the properties in each of the areas are as follows:

Coal Production and Reserves

	Production for the Year Ended December 31,			Proven and Probable Reserves at December 31, 2013		
	2013	2012	2011	Underground	Surface	Total
	(Tons in thousands)					
Area						
Appalachia						
Northern	11,505	10,486	5,251	478,448	29,333	507,781
Central	20,801	26,098	29,555	1,024,366	230,082	1,254,448
Southern	4,151	3,718	1,695	86,670	24,935	111,605
Total Appalachia	36,457	40,302	36,501	1,589,484	284,350	1,873,834
Illinois Basin	13,087	11,299	9,445	340,758	14,003	354,761
Northern Powder River Basin	2,778	2,377	2,682		97,002	97,002
Gulf Coast	970	466	523		3,737	3,737
Total	53,292	54,444	49,151	1,930,242	399,092	2,329,334

We classify low sulfur coal as coal with a sulfur content of less than 1.0%, medium sulfur coal as coal with a sulfur content between 1.0% and 1.5% and high sulfur coal as coal with a sulfur content of greater than 1.5%. Compliance coal is coal which meets the standards of Phase II of the Clean Air Act and is that portion of low sulfur coal that, when burned, emits less than 1.2 pounds of sulfur dioxide per million Btu. As of December 31, 2013, approximately 49% of our reserves were low sulfur coal and 32% of our reserves were compliance coal. Unless otherwise indicated, we present the quality of the coal throughout this Form 10-K on an as-received basis, which assumes 6% moisture for Appalachian reserves, 12% moisture for Illinois Basin reserves and 25% moisture for Northern Powder River Basin reserves. We own both steam and metallurgical coal reserves in Northern, Central and Southern Appalachia, as well as the Gulf Coast and we own steam coal reserves in the Illinois Basin and the Northern Powder River Basin. In 2013, approximately 31% of the production and 41% of the coal royalty revenues from our properties were from metallurgical coal.

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The following table sets forth our estimate of the sulfur content, the typical quality of our coal reserves and the type of coal in each area as of December 31, 2013.

Sulfur Content, Typical Quality and Type of Coal

		Sulfur Content				Typical Quality		Type of Coal	
Area	**Compliance Coal(1)**	**Low (less than 1.0%)**	**Medium (1.0% to 1.5%)**	**High (greater than 1.5%)**	**Total**	**Heat Content (Btu per pound)**	**Sulfur (%)**	**Steam**	**Metallurgical(2)**
		(Tons in thousands)						(Tons in thousands)	
Appalachia									
Northern	50,374	73,094	24,466	410,221	507,781	12,836	2.59	498,219	9,562
Central	622,692	891,119	312,030	51,299	1,254,448	13,274	0.89	859,404	395,044
Southern	74,756	80,820	27,787	2,998	111,605	13,507	0.83	79,224	32,381
Total Appalachia	747,822	1,045,033	364,283	464,518	1,873,834	13,169	1.35	1,436,847	436,987
Illinois Basin			2,193	352,568	354,761	11,499	3.27	354,761	
Northern Powder River Basin		97,002			97,002	8,800	0.65	97,002	
Gulf Coast	128	3,737			3,737	6,913	0.69	3,609	128
Total	747,950	1,145,772	366,476	817,086	2,329,334			1,892,219	437,115

(1) Compliance coal meets the sulfur dioxide emission standards imposed by Phase II of the Clean Air Act without blending with other coals or using sulfur dioxide reduction technologies. Compliance coal is a subset of low sulfur coal and is, therefore, also reported within the amounts for low sulfur coal.

(2) For purposes of this table, we have defined metallurgical coal reserves as reserves located in those seams that historically have been of sufficient quality and characteristics to be able to be used in the steel making process. Some of the reserves in the metallurgical category can also be used as steam coal.

We have engaged outside consultants to conduct reserve studies of our existing properties. These studies are an ongoing process and we will update the reserve studies based on our review of the following factors: the size of the properties, the amount of production that has occurred, or the development of new data which may be used in these studies. In connection with most acquisitions, we have either commissioned new studies or relied on recent reserve studies completed prior to the acquisition. In addition to these studies, we base our estimates of reserve information on engineering, economic and geological data assembled and analyzed by our internal geologists and engineers. There are numerous uncertainties inherent in estimating the quantities and qualities of recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. Some of these factors and assumptions include:

- future coal prices, mining economics, capital expenditures, severance and excise taxes, and development and reclamation costs;

- future mining technology improvements;

- the effects of regulation by governmental agencies; and geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experiences in other areas of our reserves.

As a result, actual coal tonnage recovered from identified reserve areas or properties may vary from estimates or may cause our estimates to change from time to time. Any inaccuracy in the estimates related to our reserves could result in royalties that vary from our expectations.

Major Coal Properties

The following is a summary of our major coal producing properties in each region:

Northern Appalachia

AFG-Ohio. The AFG-Ohio property is located in Belmont County, Ohio. In 2013, 4.9 million tons were produced from the property. We lease this property to subsidiaries of Murray Energy Corporation. Coal is produced from an underground longwall mine. Coal is shipped by rail and barge to customers including AEP, Duke Energy and First Energy.

Hibbs Run. The Hibbs Run Property is located in Marion County, West Virginia. In 2013, 3.5 million tons were produced from the property. During 2013, the lessee was acquired by Murray Energy Corporation. Coal from this property is produced from longwall mines. The royalty rate for this property is a low fixed rate per ton and has a significant effect on the per ton revenue for the region. Coal is shipped by rail to utility customers such as First Energy and PPL.

Beaver Creek. The Beaver Creek property is located in Grant and Tucker Counties, West Virginia. In 2013, 2.2 million tons were produced from this property. We lease this property to Mettiki Coal, LLC, a subsidiary of Alliance Resource Partners L.P. Coal is produced from an underground longwall mine. It is transported by truck to a preparation plant operated by the lessee. Coal is shipped primarily by truck to the Mount Storm power plant of Dominion Power.

AFG-Central PA. The AFG-Central PA property is located in Cambria and Indiana Counties, Pennsylvania. In 2013, 407,000 tons were produced from this property. We lease this property primarily to subsidiaries of Rosebud Mining Company and Alpha Natural Resources. Coal from this property is produced primarily from underground mines and the production is transported by truck or rail to utility customers and a portion is sold on the metallurgical market.

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The map below shows the location of our properties in Northern Appalachia.

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Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2013, 4.2 million tons were produced from this property. We primarily lease this property to a subsidiary of Alpha Natural Resources. Production comes from both underground and surface mines and is trucked to one of four preparation plants. Coal is shipped via both the CSX and Norfolk Southern railroads to utility and metallurgical customers. Major customers include American Electric Power, Southern Company, Tennessee Valley Authority, VEPCO and U.S. Steel and to various export metallurgical customers.

Dingess-Rum. The Dingess-Rum property is located in Logan, Clay and Nicholas Counties, West Virginia. This property is leased to subsidiaries of Alpha Natural Resources and Patriot Coal. In 2013, 3.2 million tons were produced from the property. Both steam and metallurgical coal are produced from underground and surface mines and has been historically transported by belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to steam customers such as American Electric Power, Dayton Power and Light, Detroit Edison and to various export metallurgical customers.

VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2013, 2.4 million tons were produced from this property. Coal is produced from a number of lessees, including subsidiaries of TECO and James River, from both underground and surface mines. Coal is shipped primarily by truck but also on the CSX and Norfolk Southern railroads to customers such as Southern Company, Tennessee Valley Authority, and American Electric Power.

Lone Mountain. The Lone Mountain property is located in Harlan County, Kentucky. In 2013, 1.7 million tons were produced from this property. We lease the property to a subsidiary of Arch Coal, Inc. Production comes from underground mines and is transported primarily by beltline to a preparation plant on adjacent property and shipped on the Norfolk Southern or CSX railroads to utility and metallurgical customers such as SCANA and US Steel.

Lynch. The Lynch property is located in Harlan and Letcher Counties, Kentucky. In 2013, 1.4 million tons were produced from this property. We primarily lease the property to a subsidiary of Alpha Natural Resources. Production comes from both underground and surface mines. This property has the ability to ship coal on both the CSX and Norfolk Southern railroads. In late 2012, the lessee idled a preparation plant on CSX railroad that primarily served the utility markets. The preparation plant on the CSX railroad was restarted on a limited basis in early 2014. During 2013, coal was primarily belted and trucked to a preparation plant and shipped on the Norfolk Southern railroad to metallurgical and utility customers.

Kingston. The Kingston property is located in Fayette and Raleigh Counties, West Virginia. This property is leased to a subsidiary of Alpha Natural Resources. In 2013, 1.2 million tons were produced from the property. Both steam and metallurgical coal are produced from underground and surface mines and has been historically transported by belt or truck to a preparation plant on the property or shipped raw. Coal is shipped via both the CSX railroad and by truck to barges to steam customers and various export metallurgical customers.

D.D. Shepard. The D.D. Shepard property is located in Boone County, West Virginia. This property is primarily leased to a subsidiary of Patriot Coal Corp. In 2013, 1.1 million tons were produced from the property. Both steam and metallurgical coal are produced by the lessees from underground and surface mines. Coal is transported from the mines via belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to various domestic and export metallurgical customers.

Pinnacle. The Pinnacle property is located in Wyoming and McDowell Counties, West Virginia. In 2013, 1.1 million tons of metallurgical coal were produced from our reserves on this property. We also own an overriding royalty interest on coal produced from the reserves that we do not own at this property, from which we derive additional revenues. We lease the property to a subsidiary of Cliffs Natural Resources, Inc. Production comes from a longwall mine and is transported by beltline to a preparation plant. The metallurgical coal is then shipped via railroad and barge to both domestic and export customers.

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Pardee. The Pardee property is located in Letcher County, Kentucky and Wise County, Virginia. In 2013, 758,000 tons were produced from this property. We lease the property to a subsidiary of Arch Coal, Inc. Production comes from underground mines and is transported by truck or beltline to a preparation plant on the property and shipped on the Norfolk Southern railroad primarily to domestic and export metallurgical customers such as Algoma Steel and Arcelor. During 2013, only a limited amount of production was shipped to utility customers.

The map below shows the location of our properties in Central Appalachia.

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Southern Appalachia

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2013, 2.4 million tons were produced from this property. We lease the property to a subsidiary of Cliffs Natural Resources, Inc. Production comes from an underground mine and is transported primarily by beltline to a preparation plant. The metallurgical coal is then shipped via railroad and barge to both domestic and export customers.

BLC Properties. The BLC properties are located in Kentucky and Tennessee. In 2013, 1.8 million tons were produced from these properties. We lease these properties to a number of operators including Appolo Fuels Inc., Bell County Coal Corporation and Corsa Coal Corp. Production comes from both underground and surface mines and is trucked to preparation plants and loading facilities operated by our lessees. Coal is transported by truck and is shipped via both CSX and Norfolk Southern railroads to utility and industrial customers. Major customers include South Carolina Electric & Gas, and numerous medium and small industrial customers.

The map below shows the location of our properties in Southern Appalachia.

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Illinois Basin

Williamson. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to an affiliate of Foresight Energy, and in 2013, 6.2 million tons were mined on the property. This production is from a longwall mine. Production is shipped primarily via the Canadian National railroad to customers such as Duke Energy and to various export customers.

Hillsboro. The Hillsboro property is located in Montgomery and Bond Counties, Illinois. The property is under lease to an affiliate of Foresight Energy, and in 2013, 5.3 million tons were shipped from the property. Production is currently from an underground longwall mine and is shipped via either the Union Pacific, Norfolk Southern or Canadian National railroads or by barges to domestic utilities or export customers.

Macoupin. The Macoupin property is located in Macoupin County, Illinois. The property is under lease to an affiliate of Foresight Energy, and in 2013, 927,000 tons were shipped from the property. Production is from an underground mine and is shipped via the Norfolk Southern or Union Pacific railroads or by barge to customers such as Western KY Energy and other midwest utilities or loaded into barges for shipment to export customers.

In addition to these properties, we own loadout and other transportation assets at the Williamson and Macoupin mines and at the Sugar Camp mine, which is another mine operated by an affiliate of Foresight Energy. See Transportation and Processing Assets.

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The map below shows the location of our properties in the Illinois Basin.

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Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2013, 2.8 million tons were produced from our property. A subsidiary of Westmoreland Coal Company has two coal leases on the property. Coal is produced by surface dragline mining, and the coal is transported by either truck or beltline to the four-unit 2,200-megawatt Colstrip generation station located at the mine mouth.

The map below shows the location of our properties in the Northern Powder River Basin.

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Transportation and Processing Assets

We own preparation plants and related material handling facilities that we lease to third parties. Similar to our royalty structure, the throughput fees for the use of these facilities are based on a percentage of the ultimate sales price for the material that is processed. These facilities generated $5.0 million in processing revenues for 2013.

In addition to our preparation plants, we own handling and transportation infrastructure related to certain of our coal and aggregates properties. We own loadout and other transportation assets at the Williamson and Macoupin mines in the Illinois Basin. In addition, we own rail loadout and associated infrastructure at the Sugar Camp mine, an Illinois Basin mine operated by an affiliate of Foresight Energy. While we own coal reserves at the Williamson and Macoupin mines, we do not own coal reserves at the Sugar Camp mine. For the year ended December 31, 2013, we recognized $18.0 million in revenue from these assets. We typically lease this infrastructure to third parties and collect throughput fees; however, at the loadout facility at the Williamson mine in Illinois, we operate the coal handling and transportation infrastructure and have subcontracted out that responsibility to a third party.

Aggregates and Industrial Minerals Properties

Aggregates are crushed stone, sand and gravel, utilized in the construction of the majority of our country s infrastructure. Aggregates are used in nearly every residential, commercial and industrial building construction and in most public works projects, such as roads, highways, bridges, railroad beds, dams, airports, water and sewage treatment plants and systems and tunnels. Industrial minerals include non-fuel mineral resources such as soda ash, sand, lime, potash and rare earths, among others, that are mined and processed for a wide range of industrial and consumer applications such as glass, abrasives, soaps and detergents.

In 2006, we bought our first aggregate property on the Puget Sound in Washington. Since that time, we have made several other aggregate purchases in multiple U.S. geographies, and we are actively looking at additional opportunities. We own and manage aggregate reserves, but we do not engage in the quarrying, processing or sale of aggregate-related products. We own an estimated 500 million tons of aggregate reserves located in a number of states across the country. During 2013, our lessees produced 6.2 million tons of aggregates, and aggregate royalty revenues were $7.6 million.

Equity Interest in OCI Wyoming, L.P.

We own a 49% non-controlling equity interest in OCI Wyoming, L.P., an operator of a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming. We purchased the interest in OCI Wyoming, L.P. in January 2013 for $292.5 million. Soda ash is used in the production of a variety of consumer products, including glass, chemicals, soap and paper. All soda ash is sold through an OCI-affiliated sales agent to various domestic and European customers and to American Natural Soda Ash Corporation for export. All mining and refining activities take place in one facility located in the Green River Basin, Wyoming. In 2013, we have received total distributions of $72.9 million from OCI Wyoming, including a $44.8 million special distribution made in connection with certain restructuring and refinancing transactions in July 2013 in advance of the OCI Resources LP initial public offering.

Oil and Natural Gas Properties

We generate oil and gas revenues from royalty, overriding royalty and non-operated working interests in producing oil and gas wells. During 2013, we generated $17.1 million in revenues from our interests in oil and gas properties. Our interests in oil and natural gas producing properties are in three primary regions: the Appalachian Basin, the Williston Basin and the Mid-Continent region. NRP also owns interests in other oil and gas properties in several states, including interests in properties located in northern Louisiana owned through BRP LLC, a venture with International Paper in which NRP owns 51%. See BRP Properties.

Oil and gas royalty revenues include production payments as well as bonus payments and are recognized on the basis of hydrocarbons sold by lessees and the corresponding revenues from those sales. Generally, the lessees make payments based on a percentage of the selling price. Some leases are subject to minimum annual payments or delay rentals. Revenues related to our non-operated working interests in oil and gas assets are recognized on the basis of our net revenue interests in hydrocarbons produced. We also incur capital expenditures and operating expenses associated with the non-operated working interests. Our revenues fluctuate based on changes in the market prices for oil and natural gas, the decline in production from producing wells, and other factors affecting the third-party oil and natural gas exploration and production companies that operate wells, including the cost of development and production.

We own royalty interests in approximately 261,000 net acres where we have leased certain portions of our owned mineral interests to third parties. We own overriding royalty interests or non-operated working interests in approximately 100,000 net acres. The overriding royalty interests are primarily located in Appalachian Basin in West Virginia and Pennsylvania, including in the Marcellus Shale, and in the Haynesville Shale in Louisiana.

Producing Oil and Natural Gas Wells

The following tables set forth the gross and net producing oil and natural gas wells in which NRP held working interests and royalty or overriding royalty interests as of December 31, 2013 by region. Gross wells represent the number of wells in which NRP owns an interest. Net wells represent the total of our fractional working interests or royalty interests, as applicable, owned in gross wells. NRP does not operate any wells.

	Working Interest Wells			
	Oil		**Natural Gas**	
	Gross	**Net**	**Gross**	**Net**
Williston Basin	218	18		

As of December 2013, NRP also owned non-operated working interests in 40 gross oil wells in various stages of development in the Williston Basin.

	Royalty and Overriding Royalty Interest Wells			
	Oil		**Natural Gas**	
	Gross	**Net**	**Gross**	**Net**
Appalachian Basin(1)	30	3.0	711	71.3
Mid-Continent	40	1.7	6	0.7
Williston Basin	25	0.1		
Louisiana (BRP properties)	12	0.1	274	7.4
Total	107	4.9	991	79.4

(1) 41 gross (1.3 net) natural gas wells are attributable to our overriding royalty interest in the Appalachian Basin acquired in 2012. The remaining wells are primarily conventional oil and gas wells or coal bed methane located in the southern portion of the Appalachian Basin.

Acreage Summary

The following table sets forth the gross and net mineral acres owned by NRP and leased to third parties as of December 31, 2013 by region.

	NRP Fee Mineral Acres Under Lease to Third Parties	
	Gross	**Net**
Appalachian Basin(1)	202,772	199,718

Mid-Continent	13,061	11,211
Louisiana (BRP properties)	63,661	50,216
Total	279,494	261,145

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(1) The majority of our Appalachian Basin fee mineral acreage consists of coal bed methane and oil and gas rights in properties located in the southern portion of the basin.

The following table contains a summary of the gross and net acres leased from third parties to NRP or in which NRP had an overriding royalty interest as of December 31, 2013:

	Acres Leased to NRP or ORRI	
	Gross	Net
Appalachian Basin(1)	83,159	55,284
Williston Basin	82,478	15,746
Louisiana (BRP properties)(2)	29,000	29,000
Total	194,637	100,030

(1) Consists of overriding royalty interests acquired in December 2012. Certain of the leases subject to the overriding royalty interest originally acquired have expired but may be renewed. To the extent those leases are renewed, our overriding royalty interest in those properties will continue.

(2) Consists of a 1% overriding royalty interest.

BRP Properties

BRP is a venture between NRP and International Paper Company, of which NRP owns a 51% interest. As of December 31, 2013, BRP had acquired, in several stages from International Paper, approximately 10 million mineral acres in 31 states. While the vast majority of the 10 million acres remain largely undeveloped and underexplored, BRP currently holds 59 revenue generating mineral leases and 17 cell tower leases. In addition, a significant number of mineral prospects and deposits with yet undetermined commercial potential have been identified through a variety of efforts including exploration drilling, coring, drill logs, electric logs, inferences derived from published information, geological reports, geological maps, in-house efforts and consulting investigations. These prospects and deposits are not necessarily near-term commercial opportunities due to a variety of factors such as location, market, economic and production uncertainties, but have long-term development potential.

BRP s assets include approximately 300,000 gross acres of oil and gas mineral rights in Louisiana, of which over 54,000 acres were leased under 41 leases as of December 31, 2013. In addition to the leased mineral acreage, BRP holds a 1% gross production royalty interest on approximately 29,000 mineral acres in Louisiana. The remaining oil and gas mineral acreage in Louisiana is not leased but a number of acres are in areas with development potential. BRP has over 500 acres leased in Pennsylvania and approximately 300 acres leased in Texas.

As of December 31, 2013, BRP owned nearly 95,000 net mineral acres of coal rights (primarily lignite) in the Gulf Coast region, of which approximately 5,000 acres are leased under four separate leases in Louisiana and Alabama. In addition to the coal rights, BRP has aggregate reserves (including limestone, granite, clay, and sand and gravel) under lease in six states.

BRP also owns copper rights in Michigan s Upper Peninsula that are subject to a development agreement with Highland Copper Company Inc. By the end of 2013, Highland had drilled approximately 230 core holes representing approximately 115,000 total feet that have been cored, sampled and analyzed for copper. Highland expects to complete a feasibility study on the reserves in 2014.

Other mineral rights held by BRP as of December 31, 2013 included coalbed methane rights in four Gulf Coast states, metal prospect rights in four states, approximately 450,000 acres of water and water royalty rights in East Texas, geothermal rights and geothermal royalty interests in the Gulf Coast and Pacific Northwest, and carbon sequestration rights primarily in the Gulf Coast region.

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The map below illustrates the location of BRP s current mineral rights.

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Significant Customers

In 2013, we had total revenues of $88.4 million from Foresight Energy and its affiliated companies and $55.1 million from Alpha Natural Resources. Each of these lessees represented more than 10% of our total revenues. The loss of one or both of these lessees could have a material adverse effect on us. In addition, the closure or loss of revenue from Foresight s Williamson mine, which accounted for 13% of our revenue in 2013, could have a material adverse effect on us, but we do not believe that the loss of any other single mine on our properties would have a material adverse effect on our revenues or distributable cash flow.

Competition

We face competition from other land companies, coal producers, international steel companies and private equity firms in purchasing coal reserves and royalty producing properties. Numerous producers in the coal industry make coal marketing intensely competitive. Our lessees compete among themselves and with coal producers in various regions of the United States for domestic sales. The industry has recently undergone significant consolidation. This consolidation has led to a number of our lessees parent companies having significantly larger financial and operating resources than their competitors. Our lessees compete with both large and small producers nationwide on the basis of coal price at the mine, coal quality, transportation cost from the mine to the customer and the reliability of supply. Continued demand for our coal and the prices that our lessees obtain are also affected by demand for electricity and steel, as well as government regulations, technological developments and the availability and the cost of generating power from alternative fuel sources, including nuclear, natural gas and hydroelectric power.

OCI Wyoming, which operates a trona mine and soda ash refinery in the Green River Basin, Wyoming, faces competition from a number of soda ash producers in the United States, Europe and Asia, some of which have greater market share and greater financial, production and other resources than OCI Wyoming does. Some of OCI Wyoming s competitors are diversified global corporations that have many lines of business and some have greater capital resources and may be in a better position to withstand a long term deterioration in the soda ash market. Other competitors, even if smaller in size, may have greater experience and stronger relationships in their local markets. Competitive pressures could make it more difficult for OCI Wyoming to retain its existing customers and attract new customers, and could also intensify the negative impact of factors that decrease demand for soda ash in the markets it serves, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of soda ash.

The oil and natural gas industry is intensely competitive, and we compete with other companies in that industry who have greater resources than we do. These companies may be able to pay more for productive oil and natural gas properties and may be able to expend greater resources to evaluate properties and attract and maintain industry personnel. In addition, these companies may have a greater ability to make acquisitions in times of low commodity prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Title to Property

We owned approximately 99% of our coal and aggregate reserves in fee as of December 31, 2013. We lease the remainder from unaffiliated third parties. As of December 31, 2013, we owned certain of our oil and gas reserves in fee and leased our non-operated working interests in the Williston Basin from third parties. We believe that we have satisfactory title to all of our mineral properties, but we have not had a qualified title company confirm this belief. Although title to these properties is subject to encumbrances in certain cases, such as customary easements, rights-of-way, interests generally retained in connection with the acquisition of real property, licenses, prior reservations, leases, liens, restrictions and other encumbrances, we believe that none of these burdens will materially detract from the value of our properties or from our interest in them or will materially interfere with their use in the operations of our business.

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For most of our properties, the surface, oil and gas and mineral or coal estates are not owned by the same entities. Some of those entities are our affiliates. State law and regulations in most of the states where we do business require the oil and gas owner to coordinate the location of wells so as to minimize the impact on the intervening coal seams. We do not anticipate that the existence of the severed estates will materially impede development of the minerals on our properties.

Regulation and Environmental Matters

General. Our lessees are obligated to conduct mining operations in compliance with all applicable federal, state and local laws and regulations. These laws and regulations include matters involving the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, plant and wildlife protection, limitations on land use, storage of petroleum products and substances which are regarded as hazardous under applicable laws and management of electrical equipment containing PCBs. Because of extensive, comprehensive and often ambiguous regulatory requirements, violations during mining operations are not unusual and, notwithstanding compliance efforts, we do not believe violations by our lessees can be eliminated entirely. However, to our knowledge none of the violations to date, nor the monetary penalties assessed, have been material to our lessees. We do not currently expect that future compliance will have a material effect on us.

While it is not possible to quantify the costs of compliance by our lessees with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. The lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closures, including the cost of treating mine water discharge when necessary. We do not accrue for such costs because our lessees are both contractually liable and liable under the permits they hold for all costs relating to their mining operations, including the costs of reclamation and mine closures. Although the lessees typically accrue adequate amounts for these costs, their future operating results would be adversely affected if they later determined these accruals to be insufficient. In recent years, compliance with these laws and regulations has substantially increased the cost of coal mining for all domestic coal producers.

In addition, the electric utility industry, which is the most significant end-user of coal, is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for coal mined by our lessees. The possibility exists that new legislation or regulations could be adopted that have a significant impact on the mining operations of our lessees or their customers ability to use coal and may require our lessees or their customers to change operations significantly or incur substantial costs that could impact us.

Many of the statutes discussed below also apply to exploration and development activities associated with our oil and natural gas investments and to the aggregates and industrial mineral mining operations in which we hold interests, and therefore we do not present a separate discussion of statutes related to those activities.

Air Emissions. The Federal Clean Air Act and corresponding state and local laws and regulations affect all aspects of our business. The Clean Air Act directly impacts our lessees coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. There have been a series of federal rulemakings that are focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technologies and other measures required under U.S. Environmental Protection Agency (EPA) regulations will make it more costly to operate coal-fired power plants and could make coal a less attractive or even effectively prohibited fuel source in the planning and building of power plants in the future. Any reduction in coal s share of power generating capacity could negatively impact our lessees ability to sell coal, which would have a material effect on our coal royalty revenues.

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In March 2005, the EPA issued a final Clean Air Interstate Rule (CAIR), which caps nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. Since a majority of controls required by the CAIR have been installed, we believe that the financial impact of the CAIR on coal markets has been factored into the price of coal nationally and that its impact on demand has largely been taken into account by the marketplace. However, in response to a remand of CAIR by the Court of Appeals for the D.C. Circuit on July 11, 2008, the EPA on August 8, 2011 adopted a replacement program, called the Cross-State Air Pollution Rule (CSAPR), which is both broader in its geographic coverage and deeper in emission reductions than required by CAIR. The CSAPR, in turn, was vacated by opinion of the D.C. Circuit on August 21, 2012. The U.S. Supreme Court presently is considering EPA s appeal of that decision, having heard oral argument on it in December 2013. Unless and until the Court reverses the D.C. Circuit s vacatur of CSAPR, that rule remains unenforceable, but all state regulations that were based on the CAIR are still in effect. We are unable to predict whether ongoing judicial review proceedings may reinstate CSAPR or what rules EPA may propose in the event that the vacatur is upheld, and, therefore, unable to predict any effect on NRP.

In June 2005, EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. Under the Regional Haze Rule, affected states were to have developed implementation plans by December 17, 2007, that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. The vast majority of states failed to submit their plans by December 17, 2007, and the EPA issued a Finding of Failure to Submit plans on January 15, 2009. On May 30, 2012, the EPA Administrator signed a final rule under which the emission caps imposed under the CSAPR for a given state would supplant the obligations of that state with regard to visibility protection. EPA s plans to revisit this rule in light of the vacatur of the CSAPR have yet to be announced.

In February 2012, EPA published the Mercury and Air Toxics Rule (MATS), which imposes limits on the hazardous air pollutant emissions allowed for the nation s existing and future coal-fueled generation fleet. Certain requirements of the MATS rule will become effective in 2015. These restrictions have contributed and will continue to contribute to coal-fired power plant retirements. In response to legal challenges, EPA in April 2013 published revisions to the standards for new units to make them more achievable. Legal challenges to the remaining suite of MATS rules remain pending with the D.C. Circuit, which heard oral argument in December 2013. The limits imposed by those rules may result in additional coal plant retirements or limit demand for or otherwise restrict sales of our lessees coal, which would reduce our coal-related revenues.

Other continued tightening of the already stringent regulation of emissions is likely, such as the EPA s revision to the national ambient air quality standard for sulfur dioxide finalized in June 2010. As a result of these and other tightening of ambient air quality standards, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. These plan revisions may call for significant additional emission control at coal-fired power plants.

The U.S. Department of Justice, on behalf of the EPA, has filed lawsuits against a number of utilities with coal-fired electric generating facilities alleging violations of the new source review provisions of the Clean Air Act. The EPA has alleged that certain modifications have been made to these facilities without first obtaining permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for our coal could be affected, which could have an adverse effect on our coal royalty revenues.

Carbon Dioxide and Greenhouse Gas Emissions. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs), present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to warming of the Earth s atmosphere and other climatic changes. Legal challenges to these findings have been rejected by the D.C. Circuit Court of Appeals, and the Supreme Court declined to review the intermediate appellate court s rulings with respect to the endangerment finding. Based on its findings, EPA has begun adopting and implementing regulations to restrict emissions of GHGs under various provisions of the Clean Air Act. Shortly after issuing its finding, EPA adopted rules regulating GHG emissions from motor vehicles, and other rules requiring permits for emissions of GHGs from many stationary sources, including coal-fired electric power plants, effective January 2,

2011. As a result of revisions to its preconstruction permitting rules, EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominately carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants. The U.S. Supreme Court presently is considering the legality of those rules, which were upheld by the D.C. Circuit Court of Appeals.

EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including coal-fired electric power plants, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

On January 8, 2014, EPA published proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. President Obama has directed EPA to issue proposed regulations on existing fossil fuel-fired power plants in June 2014. We expect that EPA s proposed regulations for both new and existing power plants will negatively affect the viability of coal-fired power generation, which will ultimately reduce coal consumption and the production of coal from our properties.

Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. Other regional programs are being considered in several regions of the country. It is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact our lessees coal sales, and thereby have an adverse effect on our coal royalty revenues.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977 (SMCRA) and similar statutes enacted and enforced by the states impose on mine operators the responsibility of reclaiming the land and compensating the landowner for types of damages occurring as a result of mining operations. To ensure compliance with any reclamation obligations, mine operators are required to post performance bonds. In conjunction with mining the property, our coal lessees are contractually obligated under the terms of our leases to comply with all federal, state and local laws, including SMCRA. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the reclamation plan approved by the state regulatory authority. In addition, higher and better uses of the reclaimed property are encouraged. Regulatory authorities or individual citizens who bring civil actions under SMCRA may attempt to assign the liabilities of our coal lessees to us if any of these lessees are not financially capable of fulfilling those obligations.

Hazardous Materials and Waste. The Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or the Superfund law) and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and companies that improperly stored or disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

Products such as explosives used by coal companies in operations generate waste containing hazardous substances. We could become liable under federal and state Superfund and waste management statutes if our lessees are unable to pay environmental cleanup costs. CERCLA authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment, and to seek recovery from the responsible classes of persons of the costs they incurred in connection with such response. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment.

In June 2010, EPA released a proposed rule to regulate the disposal of certain Coal Combustion Residuals (CCR), often referred to as coal ash, from electric utilities. The proposed rule sets forth two proposed avenues for the regulation of CCR under the Resource Conservation and Recovery Act (RCRA). The first option calls for regulation of CCR under Subtitle C as a hazardous waste, which creates a comprehensive program of federally enforceable requirements for waste management and disposal. The second option calls for regulation of CCR under Subtitle D as a solid waste, which gives EPA authority to set performance standards for solid waste management facilities and would be enforced primarily through state agencies and citizen suits. Under both options, EPA would establish dam safety requirements to address structural integrity of surface impoundments to prevent catastrophic releases. The proposal leaves intact the exemption for beneficial uses of CCR, except for land application. In April 2012, several environmental organizations filed suit against EPA to compel EPA to take action on the proposed rule. EPA conducted additional information collections in August 2013; however, by year-end 2013, EPA had not finalized CCR rules nor established a timeline for finalization. In a consent decree filed on January 29, 2014, EPA has agreed to take final action by December 19, 2014. Although EPA has indicated that coal ash use may be appropriate under certain circumstances, if CCR were re-classified as hazardous waste, regulations may impose restrictions on ash disposal, provide specifications for storage facilities, require groundwater testing and impose restrictions on storage locations, which could increase our lessees operating costs and potentially reduce their ability to produce coal, which could affect our coal royalty revenues. In addition, contamination caused by the past disposal of CCR, including coal ash, can lead to material liability to our lessees under RCRA or other federal or state laws and potentially reduces the demand for coal.

Water Discharges. Our lessees operations can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations create two permitting programs for our lessees. The National Pollutant Discharge Elimination System (NPDES) program under Section 402 of the statute is administered by the states or the EPA and regulates the concentrations of pollutants in discharges of waste and storm water from a mine site. The Section 404 program is administered by the Army Corps of Engineers and regulates the placement of the overburden and fill material into channels, streams and wetlands that comprise waters of the United States. The scope of waters that may fall within the jurisdictional reach of the Clean Water Act is expansive and may include land features not commonly understood to be a stream or wetlands. The Clean Water Act and its regulations prohibit the unpermitted discharge of pollutants into such waters, including those from a spill or leak. Similarly, Section 404 also prohibits discharges of fill material and certain other activities in waters unless authorized by the issued permit.

Our lessees generally obtain individual permits from the Corps of Engineers authorizing the construction of valley fills for the disposal of overburden from mining operations. The application process for acquiring individual permits has become more cumbersome and can require the preparation of an environmental impact statement as part of the application. Small underground coal mines that must construct fills, limited by acreage and length, as part of their mining operations may qualify for another version of the Section 404 permit known as nationwide permit 50. Both individual and nationwide permits are subject to challenge in citizens lawsuits. Such challenges result in delays in our lessees obtaining the required mining permits to conduct their operations, which could, in turn, have an adverse effect on our coal-related revenues.

Beginning in 2009, the EPA put in place a series of policies for mines in Central Appalachia that have had the effect of slowing the issuance of both Section 404 fill permits by the Corps and Section 402 NPDES permits by state agencies. These policies, among other things, seek to impose limits on specific conductance (conductivity) and sulfate at levels that can be unachievable absent treatment at many mines. The technologies available to treat conductivity and/or sulfate are expensive and may be impracticable at all but the largest underground mines. These policies are subject to challenge in federal district court in Washington, D.C. in *National Mining Association v. Jackson*. In two separate opinions, the district court rejected the EPA s process for reviewing state-issued Section 402 permits and determined that the EPA s policies constituted unlawful rulemaking for conductivity and fell outside of the EPA s statutory authority. The EPA has appealed the final July 2012 decision.

In addition to government action, private citizens groups have continued to be active in bringing lawsuits against operators and landowners. In 2012 and 2013, several citizen suit group lawsuits were filed against mine operators for allegedly violating conditions in their NPDES permits requiring compliance with West Virginia s water quality standards. Some of the lawsuits allege violations of water quality standards for selenium, whereas others allege that discharges of conductivity and sulfate are causing violations of West Virginia s narrative water quality standards, which generally prohibit adverse effects to aquatic life. The citizen suit groups seek penalties as well as injunctive relief that would limit future discharges of selenium, conductivity or sulfate. While it is too early to determine the ultimate resolution of these lawsuits, any rulings requiring operators to reduce their discharges of selenium, conductivity or sulfate could result in large treatment expenses for our lessees. In 2013, several citizen group lawsuits were filed against landowners alleging ongoing discharges of pollutants, including selenium, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property has been closed, the property has been reclaimed, and the state reclamation bond has been released. While it is too early to determine the merits or predict the outcome of any of these lawsuits, any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations.

The Clean Water Act also requires states to develop anti-degradation policies to ensure non-impaired water bodies in the state do not fall below applicable water quality standards. These and other regulatory developments may restrict our lessees ability to develop new mines, or could require our lessees to modify existing operations, which could have an adverse effect on our coal royalty revenues.

In addition, Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. EPA promulgated rules for cooling water intake structures in three phases: Phase I for new facilities, Phase II for large existing electric generating plants, and Phase III for certain existing facilities and new offshore and coastal oil and gas extraction facilities. The Phase II rules were suspended in March 2007 in response to the Second Circuit decision in *Riverkeeper v. EPA*. EPA signed a settlement agreement with Riverkeeper on the rulemaking dates in 2010 and published proposed rules in April 2011. EPA has since published two notices of data availability summarizing the data received and collected since publishing the proposed rule. EPA and Riverkeeper have also agreed to modify the settlement agreement to give EPA additional time to finalize the new rule.

The Federal Safe Drinking Water Act (SDWA) and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal slurries, fly ash and flue gas scrubber sludge, and by requiring permits to conduct such underground injection activities. In addition to establishing the underground injection control program, the SDWA also imposes regulatory requirements on owners and operators of public water systems. This regulatory program could impact our lessees reclamation operations where subsidence or other mining-related problems require the provision of drinking water to affected adjacent homeowners.

Mine Health and Safety Laws. The operations of our lessees are subject to stringent health and safety standards that have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 resulted in increased operating costs and reduced productivity. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive health and safety standards on all mining operations. In addition, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung or pneumoconiosis and to some beneficiaries of miners who have died from this disease.

Mining accidents in recent years have received national attention and instigated responses at the state and national level that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. Since 2006, heightened scrutiny has been applied to the safe operations of both underground and surface mines. This increased level of review has resulted in an increase in the civil penalties that mine operators have been assessed for non-compliance. Operating companies and their supervisory employees have also been subject to criminal convictions. The Mine Safety and Health Administration (MSHA) has also advised mine operators that it will be more aggressive in placing mines in the Pattern of Violations (POV) program, if a mine s rate of injuries or significant and substantial citations exceed a certain threshold. A mine that is placed in a POV program will receive additional scrutiny from MSHA.

Mining Permits and Approvals. Numerous governmental permits or approvals such as those required by SMCRA and the Clean Water Act are required for mining operations. In connection with obtaining these permits and approvals, our lessees may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including our lessees, must submit a reclamation plan for reclaiming the mined property upon the completion of mining operations. Our lessees have obtained or applied for permits to mine a majority of the reserves that are currently planned to be mined over the next five years. Our lessees are also in the planning phase for obtaining permits for the additional reserves planned to be mined over the following five years. However, given the imposition of new requirements in the permits in the form of policies and the increased oversight review that has been exercised by the EPA, there are no assurances that they will not experience difficulty and delays in obtaining mining permits in the future. In addition, EPA has used its authority to create significant delays in the issuance of new permits and the modification of existing permits, which has led to substantial delays and increased costs for coal operators.

Regulations under SMCRA include a stream buffer zone rule that prohibits certain mining activities near streams. In 2008, the federal Office of Surface Mining (OSM), which implements SMCRA, revised the stream buffer zone rule, making it more clear that valley fills are not prohibited by the rule. Environmental groups challenged the revision to the buffer zone rule in federal court. The OSM has subsequently undertaken efforts to vacate the 2008 revision and to promulgate a new rule that could prohibit the placement of valley fills in streams. While it is too early to predict the outcome of these efforts, any regulatory change limiting or prohibiting valley fills could restrict our lessees ability to develop new mines, or could require our lessees to modify existing operations, which could have an adverse effect on our coal-related revenues.

In April 2013, in *Mingo Logan Coal Company v. EPA*, the D.C. Circuit Court ruled that the EPA has the authority under the Clean Water Act to retroactively veto a Section 404 dredge and fill permit issued at a coal mine by the U.S. Army Corps of Engineers. The decision results in the EPA s ability to veto a fill permit whenever it determines that an adverse effect will result, even if such determination is made years after the permit has been issued. The decision creates uncertainties for all companies operating with Clean Water Act fill permits and their business partners. While the specific facts of this case relate to ongoing fill activities, the broadly written language of the decision could have sweeping implications in other areas and result in increased regulatory activity by the EPA that is adverse to the mining industry. Mingo Logan filed a petition for certiorari seeking a review of the decision by the United States Supreme Court of Appeals, but there has not yet been a ruling on that petition.

Over the past year, the industry has successfully challenged EPA policy, regulations and guidance in several other court decisions, including *National Mining Association v. Jackson* and *EME Homer City Generation, L.P. v. EPA*. While each of these cases has unique facts and circumstances, the general theme in these cases is that the EPA has overreached its authority in a number of instances. However, the EPA has continued to promulgate regulations that will negatively affect the viability of coal-fired generation, which will ultimately reduce coal consumption and the production of coal from our properties. Additionally, citizens groups have continued to be active in bringing lawsuits against operators, as well as challenging permits issued by the Army Corps of Engineers. In May 2013, in *Ohio Valley Environmental Coalition Inc. v. U.S. Army Corps of Engineers*, a panel of the U.S. Court of Appeals for the Fourth Circuit upheld a previously issued Section 404 permit following a challenge by a coalition of environmental groups that the U.S. Army Corps of Engineers had failed to consider the full environmental impact of the proposed mine. Affirming the U.S. District Court s decision, the Fourth Circuit panel held that the Army Corps had issued the permit after conducting appropriate analysis of the potential environmental impact of the proposed mine. While other similar suits are pending or may be brought, this decision is an important development for the industry against citizen suit challenges of previously issued permits.

Federal and state surface mining laws require mine operators to post reclamation bonds to guarantee the costs of mine reclamation. West Virginia s bonding system requires coal companies to post site-specific bonds in an amount up to $5,000 per acre and imposes a per-ton tax on mined coal currently set at $0.279/ton, which is paid to the West Virginia Special Reclamation Fund (SRF). The site-specific bonds are used to reclaim the mining operations of companies that default on their obligations under the West Virginia Surface Coal Mining and Reclamation Act. The SRF is used where the site-specific bonds are insufficient to accomplish reclamation.

Employees and Labor Relations

We do not have any employees. To carry out our operations, affiliates of our general partner employ approximately 80 people who directly support our operations. None of these employees are subject to a collective bargaining agreement.

Segment Information

We conduct all of our operations in a single segment the ownership and leasing of natural resources and related transportation and processing infrastructure. Substantially all of our owned properties are subject to leases, and revenues are earned based on the volume and price of minerals extracted, processed or transported. Included in revenue from these natural resource properties are royalties from coal, aggregates, oil and gas, timber, related transportation and processing infrastructure revenues, as well as our equity investment in OCI Wyoming s trona mine and soda ash refinery operations.

Website Access to Company Reports

Our internet address is *www.nrplp.com*. We make available free of charge on or through our internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Also included on our website are our Code of Business Conduct and Ethics, our Disclosure Controls and Procedures Policy and our Corporate Governance Guidelines adopted by our Board of Directors, as well as the charters for our Audit Committee, Conflicts Committee and Compensation, Nominating and Governance Committee. Also, copies of our annual report, our Code of Business Conduct and Ethics, our Disclosure Controls and Procedures Policy, our Corporate Governance Guidelines and our committee charters will be made available upon written request.

Item 1A. ***Risk Factors***

Risks Related to Our Business

Coal prices have declined substantially in recent years, which has negatively affected our coal-related revenues and the value of our reserves. Further declines or a continued low price environment could have an additional adverse effect on our coal-related revenues and the value of our reserves.

Prices for both steam and metallurgical coal have declined substantially in recent years. The prices our lessees receive for their coal depend upon factors beyond their or our control, including:

- the supply of and demand for domestic and foreign coal;
- domestic and foreign governmental regulations and taxes;

the price and availability of alternative fuels, especially natural gas;

the demand for steel;

the proximity to and capacity of transportation facilities;

weather conditions; and

the effect of worldwide energy conservation measures.

Natural gas is the primary fuel that competes with steam coal for power generation. Natural gas prices remained relatively low during 2013, and a number of utilities have switched generation from steam coal to natural gas to the extent that it is practical to do so. This switching has resulted in a decline in steam coal prices, and to the extent that natural gas prices remain low, steam coal prices will also remain low. In addition, prices for metallurgical coal hit multi-year lows in 2013 despite increased global demand for steel. Lower prices have reduced the quantity of coal that may be economically produced from our properties, which has in turn reduced our coal-related revenues and the value of our coal reserves. Further declines or a continued low price environment could have an additional adverse effect on our coal-related revenues or the value of our reserves. A long term asset generally is deemed impaired when the future expected cash flow from its use and disposition is less than its book value. With the continued weakness in the coal markets, we intend to closely monitor our coal assets impairment risk. Future impairment analyses could result in downward adjustments to the carrying value of our assets.

Our coal lessees mining operations are subject to operating risks that could result in lower coal-related revenues to us.

Aside from pricing risk, the most significant risk faced by coal lessees that impacts NRP is permitting. As a result of recent judicial decisions and the increased involvement of the Administration and the EPA in the permitting process, there is substantial uncertainty relating to the ability of our coal lessees to be issued permits necessary to conduct mining operations. The non-issuance of permits has limited the ability of our coal lessees to open new operations, expand existing operations, and may preclude new acquisitions in which NRP might otherwise be involved.

Our royalty revenues are largely dependent on our lessees level of production from our mineral reserves, and any interruptions to the production of coal from our reserves would reduce our coal-related revenues. The level of our lessees production is subject to operating conditions or events beyond their or our control including:

the inability to acquire necessary permits or mining or surface rights;

changes or variations in geologic conditions, such as the thickness of the mineral deposits and, in the case of coal, the amount of rock embedded in or overlying the coal deposit;

the price of natural gas, which is a competing fuel in the generation of electricity;

changes in governmental regulation and policy related to the coal industry or the electric utility industry;

mining and processing equipment failures and unexpected maintenance problems;

interruptions due to transportation delays;

adverse weather and natural disasters, such as heavy rains and flooding;

labor-related interruptions; and

fires and explosions.

Our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If our lessees are pursued for these sanctions, costs and liabilities, their mining operations and, as a result, our royalty revenues and other coal-related revenues could be adversely affected.

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A sustained reduction or further decrease in the demand for metallurgical coal could result in lower coal production by our lessees, which would reduce our coal-related revenues.

Our lessees produce a significant amount of the metallurgical coal that is used in both the U.S. and foreign steel industries. In 2013, approximately 31% of the coal production and 41% of the coal royalty revenues from our properties were from metallurgical coal. The first quarter 2014 benchmark price for metallurgical coal is at a multi-year low of $143 per metric ton. Since the amount of steel that is produced is tied to global economic conditions, a continuation of current conditions or a further decline in those conditions could result in the decline of steel, coke and metallurgical coal production. Global production of steel continues to outpace demand. In addition, rising exports of metallurgical coal from Australia continue to have a negative effect on prices received for metallurgical coal produced in the United States. Since metallurgical coal is priced higher than steam coal, some mines on our properties may only operate profitably if all or a portion of their production is sold as metallurgical coal. If these mines are unable to sell metallurgical coal, they may not be economically viable and may be temporarily idled or closed.

Changes in fuel consumption patterns by electric power generators resulting in a decrease in the use of coal have resulted in and will continue to result in lower coal production by our lessees and reduced coal-related revenues.

The amount of coal consumed for domestic electric power generation is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants and environmental and other governmental regulations. We expect new power plants will be built to produce electricity. Most of these new power plants will be fired by natural gas because of lower construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of the federal Clean Air Act have resulted in more electric power generators shifting from coal to natural-gas-fired power plants, or to other alternative energy sources such as solar and wind. In addition, the proposed rules promulgated by the EPA on greenhouse gas emissions from new power plants are expected to further limit the construction of new coal-fired generation plants in favor of alternative sources of energy. We expect that EPA s proposed regulations for both new and existing power plants will negatively affect the viability of coal-fired power generation. These changes have resulted in reduced coal consumption and the production of coal from our properties and are expected to continue to have an adverse effect on our coal-related revenues.

The adoption of climate change legislation or regulations restricting emissions of greenhouse gases could result in reduced demand for our coal.

In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to warming of the Earth s atmosphere and other climatic changes. Legal challenges to these findings have been rejected by the D.C. Circuit Court of Appeals, and the Supreme Court declined to review the intermediate appellate court s rulings with respect to the endangerment finding. Based on its findings, EPA has begun adopting and implementing regulations to restrict emissions of GHGs under various provisions of the Clean Air Act. Shortly after issuing its finding, EPA adopted rules regulating GHG emissions from motor vehicles, and other rules requiring permits for emissions of GHGs from many stationary sources, including coal-fired electric power plants, effective January 2, 2011. As a result of revisions to its preconstruction permitting rules, EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominately carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants. The U.S. Supreme Court presently is considering the legality of those rules, which were upheld by the D.C. Circuit Court of Appeals.

EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including coal-fired electric power plants, on an annual basis, beginning in 2011 for

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emissions occurring after January 1, 2010, as well as certain oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

On January 8, 2014, EPA published proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. President Obama has directed EPA to issue proposed regulations on existing fossil fuel-fired power plants in June 2014. We expect that EPA s proposed regulations for both new and existing power plants will negatively affect the viability of coal-fired power generation, which will ultimately reduce coal consumption and the production of coal from our properties.

Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. Other regional programs are being considered in several regions of the country. It is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact our lessees coal sales, and thereby have an adverse effect on our coal royalty revenues.

In addition to the climate change legislation, our lessees are subject to numerous other federal, state and local laws and regulations that may limit their ability to produce and sell minerals from our properties. In addition, our oil and gas operations are also subject to numerous laws and regulations.

Our lessees may incur substantial costs and liabilities under increasingly strict federal, state and local environmental, health and safety laws, including regulations and governmental enforcement policies. The oil and gas and soda ash production operations in which we hold interests are also subject to numerous laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our or our lessees operations.

In February 2012, EPA published the MATS rule, which imposes limits on the hazardous air pollutant emissions allowed for the nation s existing and future coal-fueled generation fleet. Certain requirements of the MATS rule will become effective in 2015. These restrictions have contributed and will continue to contribute to coal-fired power plant retirements, including causing some existing plants that would otherwise be able to continue operations but for the requirements of the MATS rule to announce closures. Legal challenges to some portions of the MATS rules are pending with the D.C. Circuit. When determined, the limits imposed by those rules may result in additional coal plant retirements or limit demand for or otherwise restrict sales of our lessees coal, which would reduce our coal-related revenues.

New environmental legislation, new regulations and new interpretations of existing environmental laws, including regulations governing permitting requirements, could further regulate or tax the mineral and oil and gas industries and may also require significant changes to operations, the incurrence of increased costs or the requirement to obtain new or different permits, any of which could decrease our revenues and have a material adverse effect on our financial condition or results of operations.

As a result of ongoing consolidation in the coal industry and our partnership with Foresight Energy, we derive a large percentage of our revenues from a small number of coal lessees.

In 2013, we derived 25% of our revenues from Foresight Energy and its affiliated companies and 15% from Alpha Natural Resources. Foresight s Williamson mine alone was responsible for approximately 13% of our revenues in 2013. As a result, we have significant concentration of revenues with those lessees, although in most cases, with the exception of Williamson, the exposure is spread out over a number of different mining operations

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and leases. If our lessees merge or otherwise consolidate, or if we acquire additional reserves from existing lessees, then our revenues could become more dependent on fewer mining companies. If issues occur at those companies that impact their ability to pay us royalties, our royalty revenues and ability to make future distributions would be adversely affected.

Prices for soda ash, crude oil and natural gas are volatile. Any substantial or extended decline in soda ash or crude oil and natural gas prices could have an adverse effect on our results of operations.

The market price of soda ash directly affects the profitability of OCI Wyoming s soda ash production operations. If the market price for soda ash declines, OCI Wyoming s sales will decrease. Historically, the global market and, to a lesser extent, the domestic market for soda ash have been volatile, and those markets are likely to remain volatile in the future. In addition, crude oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. These markets will likely continue to be volatile in the future. The prices OCI Wyoming receives for its soda ash and the prices we receive with respect to our interests in oil and gas producing assets depend on numerous factors beyond our control, including worldwide and regional economic and political conditions impacting supply and demand. Substantial or extended declines in prices for these commodities could have a material adverse effect on our results of operations. In addition, OCI Wyoming relies on natural gas as the main energy source in its soda ash production process. Accordingly, high natural gas prices increase OCI Wyoming s cost of production and affect its competitive cost position when compared to other foreign and domestic soda ash producers.

Our business will be adversely affected if we are unable to make acquisitions or access the capital markets to finance our growth.

Because our reserves decline as our lessees mine our minerals, our future success and growth depend, in part, upon our ability to make acquisitions, including mineral reserve acquisitions to replace reserves that are mined. If we are unable to make acquisitions on acceptable terms, our revenues will decline as our reserves are depleted. Our ability to acquire additional mineral reserves or make other acquisitions is dependent in part on our ability to access the capital markets. We cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues, results of operations and quarterly distributions. In addition, if we are unable to successfully integrate the companies, businesses or properties we are able to acquire, our revenues may decline and we could experience a material adverse effect on our business, financial condition or results of operations.

There is a possibility that any acquisition could be dilutive to our earnings and reduce our ability to make distributions to unitholders. Any debt we incur to finance an acquisition may also reduce our ability to make distributions to unitholders. Our ability to make acquisitions in the future also could be limited by restrictions under our existing or future debt agreements, competition from other mineral companies for attractive properties or the lack of suitable acquisition candidates.

We may be subject to risks in connection with oil and gas asset acquisitions.

The acquisition of oil and gas properties requires an assessment of several factors, including:

- recoverable reserves;
- future crude oil and natural gas prices and their differentials;
- future development costs, operating costs and property taxes; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties we believe to be generally consistent with industry practices. Our

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review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities prior to acquisition. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller of the subject properties may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

If our lessees do not manage their operations well, their production volumes and our royalty revenues could decrease.

We depend on our lessees to effectively manage their operations on our properties. Our lessees make their own business decisions with respect to their operations within the constraints of their leases, including decisions relating to:

- the payment of minimum royalties;
- marketing of the minerals mined;
- mine plans, including the amount to be mined and the method of mining;
- processing and blending minerals;
- expansion plans and capital expenditures;
- credit risk of their customers;
- permitting;
- insurance and surety bonding;
- acquisition of surface rights and other mineral estates;
- employee wages;
- transportation arrangements;
- compliance with applicable laws, including environmental laws; and
- mine closure and reclamation.

A failure on the part of one of our lessees to make royalty payments, including minimum royalty payments, could give us the right to terminate the lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement lessee. We might not be able to find a replacement lessee and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the existing lessee could be subject to bankruptcy proceedings that could further delay the execution of a new lease or the assignment of the existing lease to another operator. If we enter into a new lease, the replacement operator might not achieve the same levels of production or sell minerals at the same price as the lessee it replaced. In addition, it may be difficult for us to secure new or replacement lessees for small or isolated mineral reserves, since industry trends toward consolidation favor larger-scale, higher-technology mining operations in order to increase productivity.

Our investments in operating businesses expose us to risks that we do not experience in the royalty business. In addition, we have limited control over the activities on properties that we do not operate.

Our 49% interest in the trona mining and soda ash refining operations of OCI Wyoming and our ownership of non-operated working interests in oil and gas properties subject us to operational and other contingent liabilities to which we are not exposed through our ownership of mineral rights and royalties. Further, we only have limited approval rights with respect to OCI Wyoming, and our partner controls most business decisions, including decisions with respect to distributions and capital expenditures. Adverse developments in OCI Wyoming s business would result in decreased distributions to NRP. The oil and gas properties in which we own

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working interests are operated by third-party operators and involve third-party working interest owners. We have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures required to fund such properties. We have capital expenditures and operating expenses associated with the wells in which we own interests and are required to fund our proportionate share on any wells that we decide to participate in. Our share of capital expenditures relating to our working interests could exceed our revenues from those interests. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and materially adversely affect our financial condition and results of operations. In addition, we are ultimately responsible for operating the transportation infrastructure at the Williamson mine, and have assumed the capital and operating risks associated with that business. As a result of these investments, we could experience increased costs as well as increased liability exposure associated with operating these facilities.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal, oil and gas and other minerals from our properties.

Transportation costs represent a significant portion of the total delivered cost for the customers of our lessees. Increases in transportation costs could make coal a less competitive source of energy or could make minerals produced by some or all of our lessees less competitive than coal produced from other sources. On the other hand, significant decreases in transportation costs could result in increased competition for our lessees from producers in other parts of the country.

Our lessees depend upon railroads, barges, trucks and beltlines to deliver minerals to their customers. Disruption of those transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks and other events could temporarily impair the ability of our lessees to supply minerals to their customers. Our lessees transportation providers may face difficulties in the future that may impair the ability of our lessees to supply minerals to their customers, resulting in decreased royalty revenues to us.

In addition, OCI Wyoming transports its soda ash by rail or truck and ocean vessel. As a result, its business and financial results are sensitive to increases in rail freight, trucking and ocean vessel rates. Increases in transportation costs, including increases resulting from emission control requirements, port taxes and fluctuations in the price of fuel, could make soda ash a less competitive product for glass manufacturers when compared to glass substitutes or recycled glass, or could make OCI Wyoming s soda ash less competitive than soda ash produced by competitors that have other means of transportation or are located closer to their customers. OCI Wyoming may be unable to pass on its freight and other transportation costs in full because market prices for soda ash are generally determined by supply and demand forces. In addition, OCI Wyoming ships substantially all of its soda ash on a single rail line under one contract with the Union Pacific Railroad Company that expires during 2014. There can be no assurance that the contract will be renewed on terms favorable to OCI Wyoming or at all. Any substantial decrease in the prices OCI Wyoming receives for its soda ash or an interruption in the transportation of its soda ash could have a material adverse effect on our financial condition and results of operations.

The marketability of our crude oil and natural gas production depends in part on the availability, proximity and capacity of pipeline and rail systems owned by third parties. The lack or unavailability of capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties in which we own oil and gas interests. In addition, as a result of pipeline constraints in the Williston Basin, a significant amount of crude oil production from the region is transported by rail. Recent train derailments in the U.S. and Canada have resulted in increased regulatory scrutiny of the transportation of crude oil by rail. Any resulting regulations could result in increased transportation costs, which would negatively affect our profitability from our Williston Basin assets.

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We may incur losses and be subject to liability claims as a result of our ownership of working interests in oil and natural gas operations. Additionally, our insurance may be inadequate to protect us against, these risks.

As an owner of working interests in oil and natural gas operations, we are responsible for our proportionate share of any losses and liabilities arising from uninsured and underinsured events, which could adversely affect our business, financial condition or results of operations. We are subject to all of the risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third party service providers.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Lessees could satisfy obligations to their customers with minerals from properties other than ours, depriving us of the ability to receive amounts in excess of minimum royalty payments.

Mineral supply contracts generally do not require operators to satisfy their obligations to their customers with resources mined from specific reserves. Several factors may influence a lessee s decision to supply its customers with minerals mined from properties we do not own or lease, including the royalty rates under the lessee s lease with us, mining conditions, mine operating costs, cost and availability of transportation, and customer specifications. If a lessee satisfies its obligations to its customers with minerals from properties we do not own or lease, production on our properties will decrease, and we will receive lower royalty revenues.

Our reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of our reserves.

Our reserve estimates may vary substantially from the actual amounts of minerals our lessees may be able to economically recover from our reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of reserves necessarily depend upon a number of

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variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to:

- future prices, operating costs, capital expenditures, severance and excise taxes, and development and reclamation costs;
- future mining technology improvements;
- the effects of regulation by governmental agencies; and
- geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experiences in areas where our lessees currently mine.

Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. As a result, you should not place undue reliance on our reserve data that is included in this report.

A lessee may incorrectly report royalty revenues, which might not be identified by our lessee audit process or our mine inspection process or, if identified, might be identified in a subsequent period.

We depend on our lessees to correctly report production and royalty revenues on a monthly basis. Our regular lessee audits and mine inspections may not discover any irregularities in these reports or, if we do discover errors, we might not identify them in the reporting period in which they occurred. Any undiscovered reporting errors could result in a loss of royalty revenues and errors identified in subsequent periods could lead to accounting disputes as well as disputes with our lessees.

Risks Inherent in an Investment in Natural Resource Partners L.P.

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter depends on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits In January 2014, our board of directors declared a cash distribution of $0.35 with respect to the fourth quarter of 2013, representing a 36% decrease from the distribution level paid with respect to the third quarter of 2014. Additional decreases in the quarterly distribution may occur to the extent our board of directors determines appropriate.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

As of December 31, 2013, we and our subsidiaries had approximately $1.17 billion of total indebtedness. The terms and conditions governing our indebtedness, including NRP s 9 $^{1}/_{8}$% senior notes, Opco s revolving credit facility, term loan and senior notes, and NRP Oil and Gas s revolving credit facility:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industries in which we operate;
- increase our vulnerability to economic downturns and adverse developments in our business;

limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;

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- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness;
- make it more difficult for us to satisfy our obligations under our debt agreements and increase the risk that we may default on our debt obligations; and
- limit management s discretion in operating our business.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have sufficient funds, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity 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. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations.

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner.

Unitholders may not be able to remove our general partner even if they wish to do so.

Our general partner manages and operates NRP. Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business. Unitholders have no right to elect the general partner or the directors of the general partner on an annual or any other basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 66 2/3% of our outstanding units (including units held by our general partner and its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and
- our partnership agreement contains limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders ability to influence the manner or direction of management.

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As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

We may issue additional common units without unitholder approval, which would dilute a unitholder s existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units, without unitholder approval (subject to applicable New York Stock Exchange (NYSE) rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without unitholder approval (subject to applicable NYSE rules). The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- an existing unitholder s proportionate ownership interest in NRP will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Under Delaware law, however, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

- we do not have any employees and we rely solely on employees of affiliates of the general partner;
- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;
- the amount of cash expenditures, borrowings and reserves in any quarter may affect cash available to pay quarterly distributions to unitholders;

the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner s liability;

under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arm s-length negotiations; and

the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

The control of our general partner may be transferred to a third party without unitholder consent. A change of control may result in defaults under certain of our debt instruments and the triggering of payment obligations under compensation arrangements.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the general partner of our general partner from transferring its general partnership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the Board of Directors and officers with its own choices and to control their decisions and actions.

In addition, a change of control would constitute an event of default under our revolving credit agreement. During the continuance of an event of default under our revolving credit agreement, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us and/or declare all amounts payable by us immediately due and payable. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a qualifying income requirement. Based on our current operations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely be liable for state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of a similar tax on us in a jurisdiction in which we operate or in other jurisdictions to which we may expand could substantially reduce the cash available for distribution to you.

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The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as a partnership for U.S. federal income tax purposes.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest by the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest by the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

You are required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our unitholders are treated as partners to whom we allocate taxable income that could be different in amount than the cash we distribute, you are required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax due from you with respect to that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion and depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion and depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest applicable effective tax rate applicable to non-U.S. persons, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of our common units and for other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed into service. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a short seller to cover a short sale of common units) may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned common units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their common units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of us as a partnership for federal income tax purposes.

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in our filing two tax returns for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in taxable income for the unitholder s taxable year that includes our termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for U.S. federal income tax purposes following the termination. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

Certain federal income tax preferences currently available with respect to coal exploration and development may be eliminated as a result of future legislation.

Changes to U.S. federal income tax laws have been proposed in a prior session of Congress that would eliminate certain key U.S. federal income tax preferences relating to coal exploration and development. These changes include, but are not limited to (i) repealing capital gains treatment of coal and lignite royalties, (ii) eliminating current deductions and 60-month amortization for exploration and development costs relating to coal and other hard mineral fossil fuels, (iii) repealing the percentage depletion allowance with respect to coal properties, and (iv) excluding from the definition of domestic production gross receipts all gross receipts derived from the sale, exchange, or other disposition of coal, other hard mineral fossil fuels, or primary products thereof. If enacted, these changes would limit or eliminate certain tax deductions that are currently available with respect to coal exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our common units.

As a result of investing in our common units, you are subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.

In addition to federal income taxes, you are likely subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. You are likely required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own property and conduct business in a number of states in the United States. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all U.S. federal, state and local tax returns.

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Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties.***

The information required by this Item is included under Item 1, Business and incorporated by reference herein.

Item 3. ***Legal Proceedings***

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

Item 4. ***Mine Safety Disclosures***

Not applicable.

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PART II

Item 5. ***Market for Registrant s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities***

Our common units are listed and traded on the NYSE under the symbol NRP . As of February 20, 2014, there were approximately 42,000 beneficial and registered holders of our common units. The computation of the approximate number of unitholders is based upon a broker survey.

The following table sets forth the high and low sales prices per common unit, as reported on the NYSE Composite Transaction Tape from January 3, 2012 to December 31, 2013, and the quarterly cash distribution declared and paid with respect to each quarter per common unit.

	Price Range		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2012					
First Quarter	$ 28.70	$ 23.36	$ 0.5500	05/04/2012	05/14/2012
Second Quarter	$ 25.08	$ 21.45	$ 0.5500	08/03/2012	08/14/2012
Third Quarter	$ 23.04	$ 18.67	$ 0.5500	11/05/2012	11/14/2012
Fourth Quarter	$ 22.50	$ 16.90	$ 0.5500	02/05/2013	02/14/2013
2013					
First Quarter	$ 23.95	$ 18.93	$ 0.5500	05/06/2013	05/14/2013
Second Quarter	$ 24.37	$ 20.08	$ 0.5500	08/05/2013	08/14/2013
Third Quarter	$ 22.39	$ 18.98	$ 0.5500	11/05/2013	11/14/2013
Fourth Quarter	$ 21.57	$ 18.99	$ 0.3500	01/21/2014	01/31/2014

Cash Distributions to Partners

(In thousands)

	General Partner	Limited Partners	Total Distributions
2012 Distributions	$ 4,758	$ 233,263	$ 238,021
2013 Distributions	$ 4,930	$ 241,587	$ 246,518

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Item 6. ***Selected Financial Data***

The following table shows selected historical financial data for Natural Resource Partners L.P. for the periods and as of the dates indicated. We derived the information in the following tables from, and the information should be read together with and is qualified in its entirety by reference to, the historical financial statements and the accompanying notes included in Item 8, Financial Statements and Supplementary Data in this and previously filed Forms 10-K. These tables should be read together with Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

NATURAL RESOURCE PARTNERS L.P.

(In thousands, except per unit data)

	For the Years Ended December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
Total revenues and other income	$ 358,117	$ 379,147	$ 377,683	$ 301,401	$ 256,084
Asset impairments	$ 734	$ 2,568	$ 161,336	$	$
Income from operations	$ 236,236	$ 267,165	$ 104,135	$ 196,061	$ 153,975
Net income	$ 172,078	$ 213,355	$ 54,026	$ 154,461	$ 114,080
Basic and diluted net income per limited partner unit	$ 1.54	$ 1.97	$ 0.50	$ 1.54	$ 1.17
Distributions paid ($ per unit)	$ 2.20	$ 2.20	$ 2.17	$ 2.16	$ 2.16
Weighted average number of common units outstanding	109,584	106,028	106,028	81,917	67,702
Cash from operations	$ 247,074	$ 271,408	$ 305,574	$ 258,694	$ 210,669
Distributable Cash Flow(1)	$ 309,394	$ 298,899	$ 311,174	$ 260,274	$ 210,669
EBITDA(1)	$ 316,657	$ 328,116	$ 329,660	$ 253,074	$ 214,200
Balance sheet data:					
Cash and cash equivalents	$ 92,513	$ 149,424	$ 214,922	$ 95,506	$ 82,634
Total assets	$ 1,991,856	$ 1,764,672	$ 1,665,649	$ 1,664,036	$ 1,523,590
Long-term debt	$ 1,084,226	$ 897,039	$ 836,268	$ 661,070	$ 626,587
Partners capital	$ 616,789	$ 617,447	$ 644,915	$ 825,180	$ 765,226

(1) See Non-GAAP Financial Measures below.

Non-GAAP Financial Measures

Distributable Cash Flow

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

Our distributable cash flow represents cash flow from operations, distributions from unconsolidated investments, proceeds from sale of assets and returns on direct financing lease and contractual override. Although distributable cash flow is a non-GAAP financial measure, we believe it is a useful adjunct to net cash provided by operating activities under GAAP. Distributable cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities. Distributable cash flow may not be calculated the same for us as for other companies.

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Prior to 2013, we reduced our distributable cash flow by the amount of cash we had reserved for principal payments due on our senior notes in the next calendar year. However, to present our distributable cash flow more in line with MLP practice, we no longer reduce distributable cash flow by reserves for future principal payments. We have changed our 2009, 2010, 2011 and 2012 calculations in the table below to be comparable with our presentation for 2013. This change in our reporting of distributable cash flow does not change our long-term intention to reduce our debt.

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

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Net cash provided by operating activities	$ 247,074	$ 271,408	$ 305,574	$ 258,694	$ 210,669
Distributions from unconsolidated investments(1)	48,833				
Return on direct financing lease and contractual override	2,558	2,669			
Proceeds from sale of assets	10,929	24,822	5,600	1,580	
Distributable cash flow	$ 309,394	$ 298,899	$ 311,174	$ 260,274	$ 210,669

(1) The cash distributions that NRP received from OCI Wyoming were $72.9 million for the year ended December 31, 2013. The amount included in the table reflects the difference between the cash distributions received and the other income we recorded from the OCI Wyoming investment, which are included in net cash provided by operating activities.

EBITDA

EBITDA is a non-GAAP financial measure that we define as earnings before interest, taxes, depreciation, depletion and amortization and asset impairment. EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. EBITDA should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. EBITDA provides no information regarding a company s capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax positions. EBITDA does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital and other commitments and obligations. Our management team believes EBITDA is useful in evaluating our financial performance because this measure is widely used by analysts and investors for comparative purposes. We have not previously included EBITDA as a financial measure in our annual or quarterly reports. However, NRP entered the high-yield bond market in 2013, and EBITDA is a financial measure widely used by investors in that market. There are significant limitations to using EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating EBITDA reported by different companies.

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Reconciliation of Net income to EBITDA

	Year Ended December 31,				
	2013	2012	2011	2010	2009
			(in thousands)		
Net income	$ 172,078	$ 213,355	$ 54,026	$ 154,461	$ 114,080
Add depreciation, depletion and amortization	64,377	58,221	65,118	56,978	60,012
Add asset impairments	734	2,568	161,336		
Add interest expense, gross	64,396	53,972	49,180	41,635	40,108
Add depreciation, depletion and amortization relating to OCI Wyoming	15,072				
EBITDA	$ 316,657	$ 328,116	$ 329,660	$ 253,074	$ 214,200

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

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Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion of the financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this filing. For more detailed information regarding the basis of presentation for the following financial information, see the Notes to the Consolidated Financial Statements.

As used in this Item 7, unless the context otherwise requires: we, our and us refer to Natural Resource Partners L.P. and, where the context requires, our subsidiaries. References to NRP and Natural Resource Partners refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC or any of Natural Resource Partners L.P. s subsidiaries. References to Opco refer to NRP (Operating) LLC and its subsidiaries. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP. NRP Finance Corporation (NRP Finance) is a wholly owned subsidiary of NRP and a co-issuer with NRP on the 9.125% senior notes.

Executive Overview

Our Business

We engage principally in the business of owning, managing and leasing mineral properties in the United States. We own coal reserves in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. As of December 31, 2013, we owned or controlled approximately 2.3 billion tons of proven and probable coal reserves. We do not operate any mines, but lease our reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell our reserves in exchange for royalty payments. We also own and manage infrastructure assets that generate additional revenues for our company, particularly in the Illinois Basin.

We have made a concerted effort to diversify our business in recent years. In 2013, we spent over $365 million to acquire interests in non-coal-related operating businesses. In January 2013, we acquired a non-controlling equity interest in OCI Wyoming, L.P., an operator of a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming for $292.5 million. We also completed two acquisitions of non-operated working interests in oil and gas operations in the Williston Basin of North Dakota and Montana for an aggregate purchase price of $72 million. In addition, we own various interests in oil and gas properties that are located in other areas, including the Appalachian Basin, Louisiana and Oklahoma, and we have acquired approximately 500 million tons of aggregate reserves located in a number of states across the country.

For the year ended December 31, 2013, we recognized approximately $145.5 million (40.6%) of our revenues and other income from sources other than coal royalties, which primarily consisted of equity income from our investment in OCI Wyoming, oil and gas revenues, aggregates royalties, overriding royalties (which include coal and aggregates overrides), minimums recognized as revenue, and processing and transportation fees. The revenues that we recognize from minimums and processing/transportation are largely derived from coal-related businesses.

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

Oil and gas royalty revenues include production payments as well as bonus payments. Oil and gas royalty revenues are recognized on the basis of hydrocarbons sold by lessees and the corresponding revenues from those sales. Generally, the lessees make payments based on a percentage of the selling price. Some leases are subject to minimum annual payments or delay rentals. Revenues related to our non-operated working interests in oil and gas assets are recognized on the basis of our net revenue interests in hydrocarbons produced. We also incur

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

Our Current Liquidity Position

In September 2013, NRP, together with NRP Finance as co-issuer, sold $300.0 million of 9.125% Senior Notes due 2018 at an issue price of 99.007% of par value for net proceeds of $289 million. We used the net proceeds of the offering to repay all outstanding borrowings under Opco s revolving credit facility. Opco s revolving credit facility does not mature until August 2016 and, as of December 31, 2013, Opco had $280 million in available capacity under the facility. In August 2013, NRP Oil and Gas entered into a senior secured, reserve-based revolving credit facility with an initial $8.0 million borrowing base. During December 2013, the borrowing base was increased to $16.0 million. As of December 31, 2013, NRP Oil and Gas had the full $16.0 million available for borrowing under its revolving credit facility. As of the date of this filing, NRP Oil and Gas had $2.0 million of borrowings outstanding under its credit facility. We typically access the capital markets to refinance amounts outstanding under our revolving credit facilities as we approach the limits under those facilities, the timing of which depends on the pace and size of our acquisition program and development capital expenditures associated with our oil and gas business.

We refinanced a $35 million Opco senior note that matured in 2013, as well as $15 million of the remaining $52 million in principal payments due on Opco s senior notes during 2013. We have $81.0 million in principal payments on Opco s senior notes due in 2014. While we intend to reduce our leverage by paying the full amount with cash from operations, we may refinance some or all of these obligations as they come due.

We used $91.0 million of net proceeds from the September 2013 senior notes offering to repay principal on Opco s term loan. We also used a portion of the proceeds from the July 2013 $44.8 million special distribution from OCI Wyoming to repay $10.0 million of principal on Opco s term loan. Opco s next principal repayment obligation on the term loan is in January 2016, when Opco will be required to repay the remaining principal amount outstanding thereunder of $99.0 million.

In addition to the amounts available under our revolving credit facilities, we had $92.5 million in cash at December 31, 2013. We believe that the combination of our capacity under our revolving credit facilities and our cash on hand gives us enough liquidity to meet our current financial needs. Other than $81 million in principal repayments due on Opco s senior notes each year for the next several years, we do not have any debt maturing until 2016. In January 2014, our Board of Directors declared a cash distribution of $0.35 per unit with respect to the fourth quarter of 2013. The distribution represents a $0.20 (36%) decrease from the distribution declared and paid with respect to the third quarter of 2013. We believe that the distribution decrease will save NRP approximately $89.6 million annually and position NRP to reduce its debt over time while preserving its liquidity to pursue accretive acquisitions.

Current Results/Market Outlook

Our total revenues and other income for 2013 were $358.1 million, which were down compared to the $379.2 million in total revenues and other income received for 2012. Although our total revenues and other income were down only 5.5% from 2012, our coal royalty revenues were down approximately 18.4% from 2012 and our Central Appalachian coal royalty revenues were down approximately 32.9% from 2012. We anticipated these declines and continue to see the benefits of our diversification efforts, as our revenues and other income from sources other than coal royalties represented over 40% of our total revenues and other income in 2013, up from approximately 31% of total revenues and other income in 2012. We expect that coal royalties will represent a lower percentage of total revenues and other income in 2014. As compared to 2012, our coal royalty revenues from the Illinois Basin were up 13% in 2013, our investment in OCI Wyoming s trona mining and soda ash production operations contributed $34.2 million in other income, and our oil and gas revenues increased 86% and continue to ramp up. Despite the decrease in our coal royalty revenues during 2013, our distributable cash flow increased slightly over 2012, primarily due to the $72.9 million in distributions that we received from OCI during 2013.

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Despite NRP s solid operating and financial performance in 2013, the coal markets continue to be uncertain, and prices for both steam and metallurgical coal continue to be severely depressed. We expect that the challenges that have affected the coal markets over the last two years will continue through at least 2014. The outlook for high-cost Central Appalachian steam coal is challenging due to federal government policy and regulations combined with natural gas prices remaining at levels that are low enough to make Central Appalachian steam coal production uneconomic. In addition, the Illinois Basin continues to increase production and is displacing Central Appalachian coal at some utilities. We benefit from the Illinois Basin growth through our relationship with Foresight Energy. As a result of the exceptionally cold winter of 2013-2014, natural gas prices have increased substantially and natural gas storage levels have dropped below the five-year average. In addition, utilities have been running their coal units, including those units expected to be retired in 2015, at near full capacity, and coal stockpiles have been reduced below 2013 levels. The impact of the high natural gas prices and cold weather on thermal coal prices has been muted so far, but utilities have entered 2014 with larger spot positions than in the past, and the reduced stockpiles could force them to purchase coal on the spot market at higher prices during the peak heating and cooling seasons in 2014.

We also continue to have substantial exposure to metallurgical coal, from which we derived approximately 41% of our coal royalty revenues and 31% of the related production during 2013. The first quarter 2014 benchmark price for metallurgical coal is at a multi-year low of $143 per metric ton. Although the global demand for steel continues to increase, global production continues to outpace demand. In addition, rising exports of metallurgical coal from Australia continue to have a negative effect on prices received for metallurgical coal produced in the United States. Due to continued high global production levels and currently weak Australian and Canadian dollars, we do not anticipate metallurgical coal prices recovering in 2014.

Lessees move on and off of our properties over the course of any given year in accordance with their mine plans. Our revenues are reduced when a lessee s mine plan results in the mining of reserves adjacent to our properties that are not owned by us. These reductions are generally offset by other lessees moving their mining operations back on to our properties. During the fourth quarter of 2013, we experienced a decline in coal production due to several high-volume lessees conducting their mining operations on adjacent properties in accordance with their mine plans. We expect that the volumes of coal produced by lessees moving off of our properties for 2014 will exceed the volumes produced as lessees move back on our properties during 2014. These reduced volumes, along with continued depressed coal prices, are expected to result in a significant decrease in our coal royalty revenues during 2014 as compared to prior years. OCI Wyoming s soda ash business has performed as we projected during 2013, but the increased liquidity associated with a refinancing transaction resulted in higher than expected cash distributions to NRP in 2013, including a $44.8 million special distribution in July 2013. NRP anticipates receiving approximately $42.5 million of distributions from the OCI Wyoming investment in 2014.

Political, Legal and Regulatory Environment

The political, legal and regulatory environment continues to be difficult for the coal industry. The Environmental Protection Agency (EPA) has used its authority to create significant delays in the issuance of new permits and the modification of existing permits, which has led to substantial delays and increased costs for coal operators. Furthermore, the federal courts have recently handed down several decisions that are adverse to the coal industry. In addition, the electric utility industry, which is the most significant end-user of domestic coal, is subject to extensive regulation regarding the environmental impact of its power generation activities. On January 8, 2014, EPA published proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. President Obama has directed EPA to issue proposed regulations on existing fossil fuel-fired power plants in June 2014. We expect that EPA s proposed regulations for both new and existing power plants will negatively affect the viability of coal-fired power generation, which will ultimately reduce coal consumption and the production of coal from our properties.

In addition to government action, private citizens groups have continued to be active in bringing lawsuits against operators and landowners. In 2012 and 2013, several citizen suit group lawsuits were filed against mine operators for allegedly violating conditions in their NPDES permits requiring compliance with West Virginia s water quality standards. Some of the lawsuits allege violations of water quality standards for selenium, whereas others allege that discharges of conductivity and sulfate are causing violations of West Virginia s narrative water quality standards, which generally prohibit adverse effects to aquatic life. The citizen suit groups seek penalties as well as injunctive relief that would limit future discharges of selenium, conductivity or sulfate. While it is too early to determine the ultimate resolution of these lawsuits, any rulings requiring operators to reduce their discharges of selenium, conductivity or sulfate could result in large treatment expenses for our lessees. In 2013, several citizen group lawsuits were filed against landowners alleging ongoing discharges of pollutants, including selenium, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property has been closed, the property has been reclaimed, and the state reclamation bond has been released. While it is too early to determine the merits or predict the outcome of any of these lawsuits, any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations.

Recent Acquisitions

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

Sundance. In December 2013, we acquired non-operated working interests in oil and gas properties in the Williston Basin of North Dakota, including properties producing from the Bakken/Three Forks play, from Sundance Energy, Inc. for $33.7 million, subject to post-closing purchase price adjustments. The properties, which are all held by production are located in McKenzie, Mountrail and Dunn counties and are actively being developed.

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

OCI Wyoming. In January 2013, we acquired a non-controlling equity interest in OCI Wyoming, an operator of a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming, from Anadarko Holding Company and its subsidiary, Big Island Trona Company for $292.5 million. The acquisition agreement provides for up to $50 million in additional contingent consideration payable by us should certain performance criteria be met as defined in the purchase and sales agreement in any of 2013, 2014 or 2015. We expect to pay approximately $0.7 million in contingent consideration to Anadarko with respect to 2013.

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

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

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

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

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

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

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

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

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

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

Critical Accounting Policies

Coal and Aggregate Royalties. Coal and aggregate royalty revenues are recognized on the basis of tons of mineral sold by our lessees and the corresponding revenue from those sales. Generally, the lessees make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of mineral they sell, subject to minimum annual or quarterly payments.

Processing and Transportation Fees. Processing fees are recognized on the basis of tons of material processed through the facilities by our lessees and the corresponding revenue from those sales. Generally, the lessees of the processing facilities make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of coal that is processed and sold from the facilities. The processing leases are structured so that the lessees are responsible for operating and maintenance expenses associated with the facilities. Transportation fees are recognized on the basis of tons of coal transported over the beltlines. Under the terms of the transportation contracts, we receive a fixed price per ton for all coal transported on the beltlines.

Oil and Gas Revenues. Oil and gas royalty revenues are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. Generally, the lessees make payments based on a percentage of the selling price. Some leases are subject to minimum annual payments or delay rentals. Revenues related to our non-operated working interests in oil and gas assets are recognized on the basis of our net revenue interests in hydrocarbons produced. We also have capital expenditure and operating expenditure obligations associated with the non-operated working interests. Our revenues fluctuate based on changes in the market prices for oil and natural gas, the decline in production from producing wells, and other factors affecting the third-party oil and natural gas exploration and production companies that operate wells, including the cost of development and production.

Minimum Royalties. Most of our lessees must make minimum annual or quarterly payments which are generally recoupable over certain time periods. These minimum payments are recorded as deferred revenue when received. The deferred revenue attributable to the minimum payment is recognized as revenues either when the lessee recoups the minimum payment through production or immediately following the period during which the lessee is allowed to recoup the minimum payment.

Lessee Audits and Inspections. We periodically audit lessee information by examining certain records and internal reports of our lessees. Our regional managers also perform periodic mine inspections to verify that the information that has been submitted to us is accurate. Our audit and inspection processes are designed to identify material variances from lease terms as well as differences between the information reported to us and the actual results from each property. Our audits and inspections, however, are in periods subsequent to when the revenue is reported and any adjustment identified by these processes might be in a reporting period different from when the revenue was initially recorded.

Depreciation, Depletion and Amortization. We depreciate our plant and equipment on a straight line basis over the estimated useful life of the asset. We deplete mineral properties on a units-of-production basis by lease,

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based upon minerals mined in relation to the net cost of the mineral properties and estimated proven and probable tonnage in those properties. We amortize intangible assets on a units-of-production basis, unless classified as a temporarily idled asset then a minimum amortization is applied. Oil and natural gas non-operated working interests are depleted on a unit-of-production basis. The depletion rate is adjusted annually based upon the amount of remaining reserves as determined by a third-party. Oil and gas royalty interests are depleted on a straight-line basis over 30 years or the life of the lease, whichever is shorter. We update our estimates of reserves periodically and this may result in material adjustments to reserves and depletion rates that we recognize prospectively. Historical revisions have not been material.

Asset Impairment. A long term asset is deemed impaired in most cases when the future expected cash flow from its use and disposition is less than its book value. Impairment is measured based on the present value of the projected future cash flow compared to current book value. We have developed procedures to periodically evaluate its long-lived assets for possible impairment. These procedures are performed throughout the year and are based on historic, current and future performance and are designed to be early warning tests. If an asset fails one of the early warning tests, additional evaluation is performed for that asset that considers both quantitative and qualitative information. Undiscounted cash flow is used to evaluate recoverability with any adjustment to fair value to reflect impairment based on discounted cash flows. 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 a separate impairment evaluation be completed on a significant property. As a result of the continued weakness in the coal markets, we intend to closely monitor our coal assets impairment risk, and the impairment evaluation process may be completed more frequently if deemed necessary. Future impairment analyses could result in downward adjustments to the carrying value of our assets.

Share-Based Payments. We account for our Long-Term Incentive Plan awards under Financial Accounting Standards Board s (FASB) stock compensation authoritative guidance. This authoritative guidance provides that grants must be accounted for using the fair value method, which requires us to estimate the fair value of the grant and charge or credit the estimated fair value to expense over the service or vesting period of the grant based on fluctuations in value. In addition, this authoritative guidance requires that estimated forfeitures be included in the periodic computation of the fair value of the liability and that the fair value be recalculated at each reporting date over the service or vesting period of the grant.

Recent Accounting Pronouncements

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

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

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Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Summary of 2013 and 2012 Revenues and Production

(In thousands, except percent and per ton data)

	For the Years Ended December 31, 2013	For the Years Ended December 31, 2012	Increase (Decrease)	Percentage Change
Coal royalty revenues				
Appalachia				
Northern	$ 14,643	$ 15,768	$ (1,125)	(7)%
Central	105,004	156,390	(51,386)	(33)%
Southern	26,156	29,325	(3,169)	(11)%
Total Appalachia	145,803	201,483	(55,680)	(28)%
Illinois Basin	56,001	49,538	6,463	13%
Northern Powder River Basin	7,569	8,501	(932)	(11)%
Gulf Coast	3,290	1,212	2,078	171%
Total	$ 212,663	$ 260,734	$ (48,071)	(18)%
Coal production (tons)				
Appalachia				
Northern	11,505	10,486	1,019	10%
Central	20,801	26,098	(5,297)	(20)%
Southern	4,151	3,718	433	12%
Total Appalachia	36,457	40,302	(3,845)	(10)%
Illinois Basin	13,087	11,299	1,788	16%
Northern Powder River Basin	2,778	2,377	401	17%
Gulf Coast	970	466	504	108%
Total	53,292	54,444	(1,152)	(2)%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 1.27	$ 1.50	$ (0.23)	(15)%
Central	$ 5.05	$ 5.99	(0.94)	(16)%
Southern	$ 6.30	$ 7.89	(1.59)	(20)%
Total Appalachia	$ 4.00	$ 5.00	(1.00)	(20)%
Illinois Basin	$ 4.28	$ 4.38	(0.10)	(2)%
Northern Powder River Basin	$ 2.72	$ 3.58	(0.86)	(24)%
Gulf Coast	$ 3.39	$ 2.60	0.79	30%
Combined average gross royalty revenue per ton	$ 3.99	$ 4.79	$ (0.80)	(17)%
Aggregates				
Royalty revenues	$ 7,073	$ 6,598	$ 475	7%
Aggregate bonus royalty	$ 570	$	$ 570	N/A
Production	6,155	5,287	868	16%
Average gross royalty revenue per ton	$ 1.15	$ 1.25	$ (0.10)	(8)%

Investment in OCI Wyoming				
Equity and other unconsolidated investment earnings	$ 34,186		$ 34,186	N/A
Cash distributions received	$ 72,946		$ 72,946	N/A
Oil and Gas				
Revenues	$ 17,080	$ 9,160	$ 7,920	86%

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Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 59% of our total revenue for the year ended December 31, 2013 and 69% of our total revenue in 2012. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. The combination of lower production in Central Appalachia, a lower royalty rate in Northern Appalachia on a lease with significant production and generally lower prices being received by our lessees in all three sub-regions, were the primary reasons coal royalty revenues decreased by $55.7 million in 2013. The 5.3 million ton decrease in production in Central Appalachia was the result of our lessees reducing production in response to the weaker coal market and the effect of some lessees having a lower proportion of production on our properties. Production in Northern Appalachia increased by 1.0 million tons, but these increases were mainly on leases with a lower revenue per ton, and therefore still resulted in reduced revenue of $1.1 million. The tonnage decreases are partially offset by an increase in production in Southern Appalachia, primarily due to one of our lessees having more normal production for 2013 after it completed repairs to its preparation plant that was damaged by a tornado in 2011and restarted production in 2012. Our lessees in Southern Appalachia realized generally lower prices in 2013 versus 2012, resulting in lower revenue per ton and revenue decrease of $3.2 million.

Illinois Basin. Coal royalty revenues and production on our properties were both higher in 2013. Coal royalty revenues increased by $6.5 million and production increased by 1.8 million tons. The increased production was mainly due to production from our Hillsboro property that operated its longwall for the entire year of 2013 after beginning operations in the third quarter of 2012. The increased production and revenue from Hillsboro was partially offset by lower production from the Williamson mine, which had lower sales and lower production from the Macoupin mine, which idled one of its producing units in early 2013.

Northern Powder River Basin. Our coal royalty revenues decreased by $932,000 over last year despite a production increase of 401,000 tons on our Western Energy property. The higher production was due to the normal variations that occur due to the checkerboard nature of our ownership. The lower revenue per ton was due to the timing of revenue recognition by the lessee in the third quarter of 2012 that did not occur in 2013.

Gulf Coast. Coal royalty revenues and production were both higher in 2013. The increase in coal royalty revenue is primarily due to a mine having a greater proportion of its production on our property.

Aggregates Royalty Revenues and Production

For the year ended December 31, 2013, we recognized $7.6 million in royalty revenue from aggregates, which included bonus revenue of $0.6 million under one of our leases. For the same period for 2012, we recognized royalty revenue from aggregates of $6.6 million and no bonus royalty. We had production of 6.2 million tons and 5.3 million tons for 2013 and 2012, respectively. Also, we do not include revenues from our frac sand properties in Texas and Wisconsin in aggregate royalties, but include those revenues in overriding royalties. We received revenues of $1.0 million and $1.5 million in 2013 and 2012, respectively, from our Texas property. We also received $2.1 million in override revenue in 2013 from our frac sand property in Wisconsin, which was acquired during the fourth quarter of 2012 and did not start to contribute to revenue until 2013.

Oil and Gas Revenues

Oil and gas revenues for the years ended December 31, 2013 and 2012 were $17.1 million and $9.2 million, respectively. The results for 2013 reflect our further diversification, with investments in oil and gas providing increased revenues from our Oklahoma properties and revenue from recently acquired non-operated working interests in the Bakken/Three Forks play in North Dakota and Montana during the second half of 2013. Included in revenues for the years ended 2013 and 2012 were bonus payments of $0.3 million and $2.6 million, respectively.

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Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Summary of 2012 and 2011 Revenues and Production

(In thousands, except percent and per ton data)

	For the Years Ended December 31, 2012	For the Years Ended December 31, 2011	Increase (Decrease)	Percentage Change
Coal royalty revenues				
Appalachia				
Northern	$ 15,768	$ 20,578	$ (4,810)	(23)%
Central	156,390	196,789	(40,399)	(21)%
Southern	29,325	11,717	17,608	150%
Total Appalachia	201,483	229,084	(27,601)	(12)%
Illinois Basin	49,538	41,324	8,214	20%
Northern Powder River Basin	8,501	7,658	843	11%
Gulf Coast	1,212	1,155	57	5%
Total	$ 260,734	$ 279,221	$ (18,487)	(7)%
Coal production (tons)				
Appalachia				
Northern	10,486	5,251	5,235	100%
Central	26,098	29,555	(3,457)	(12)%
Southern	3,718	1,695	2,023	119%
Total Appalachia	40,302	36,501	3,801	10%
Illinois Basin	11,299	9,445	1,854	20%
Northern Powder River Basin	2,377	2,682	(305)	(11)%
Gulf Coast	466	523	(57)	(11)%
Total	54,444	49,151	5,293	11%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 1.50	$ 3.92	$ (2.42)	(62)%
Central	$ 5.99	$ 6.66	$ (0.67)	(10)%
Southern	$ 7.89	$ 6.91	$ 0.98	14%
Total Appalachia	$ 5.00	$ 6.28	$ (1.28)	(20)%
Illinois Basin	$ 4.38	$ 4.38	$	
Northern Powder River Basin	$ 3.58	$ 2.86	$ 0.72	25%
Gulf Coast	$ 2.60	$ 2.21	$ 0.39	18%
Combined average gross royalty revenue per ton	$ 4.79	$ 5.68	$ (0.89)	16%
Aggregates				
Royalty revenues	$ 6,598	$ 6,640	$ (42)	(1)%
Aggregate bonus royalty	$	$ 94	$ (94)	(100)%
Production	5,287	5,930	(643)	(11)%
Average gross royalty revenue per ton	$ 1.25	$ 1.12	$ 0.13	12%

Oil and Gas

Revenues	$ 9,160	$ 14,017	$ (4,857)	(35)%

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Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 69% of our total revenue for the year ended December 31, 2012 and 74% of our total revenue in 2011. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. The combination of lower production and lower prices in Central Appalachia, together with a lower royalty rate in Northern Appalachia, were the primary reasons coal royalty revenues decreased by $27.6 million in 2012. The 3.5 million ton decrease in production in Central Appalachia was the result of our lessees reducing production in response to the weaker coal market and the effect of some lessees having a lower proportion of production on our properties. Production in Northern Appalachia increased by 5.2 million tons, but these increases were mainly on leases with a lower revenue per ton, and therefore still resulted in reduced revenue of $4.8 million. The decreases are partially offset by an increase in production and revenue in Southern Appalachia, due primarily to one of our lessees resuming production for the entire year after it completed repairs to its preparation plant that was damaged by a tornado in 2011.

Illinois Basin. Coal royalty revenues and production on our properties were both higher in 2012. Coal royalty revenues increased by $8.2 million and production increased by 1.9 million tons. The increased production was mainly due to production from our Hillsboro property that began longwall operations in the third quarter of 2012. In addition, we had increased production at the Williamson mine.

Northern Powder River Basin. Our coal royalty revenues increased by $843,000 over last year despite a production decrease of 305,000 tons on our Western Energy property. The lower production was due to the normal variations that occur due to the checkerboard nature of our ownership. The higher revenue per ton was due to the timing of revenue recognition by the lessee in the third quarter of 2012.

Gulf Coast. Primarily due to production from a lease with a higher revenue per ton starting on our property in 2012, coal royalty revenues were higher in 2012 despite production being lower. The increase in production was more than offset by other lessees having a greater proportion of their production on adjacent properties. These other properties have lower revenue per ton.

Aggregates Royalty Revenues and Production

For the year ended December 31, 2012, we recognized $6.6 million in royalty revenue from aggregates. For the same period for 2011, we recognized royalty revenue from aggregates of $6.7 million, which included bonus revenue of $0.1 million under one of our leases. We had production of 5.3 million tons and 5.9 million tons for 2012 and 2011, respectively. Although production declined, our revenue per ton increased and helped keep the royalty revenue nearly constant. Also, we do not include revenues from our frac sand properties in Texas and Wisconsin in aggregate royalties, but include those revenues in overriding royalties. We received $1.5 million in revenues from the Texas property in 2012.

Oil and Gas Revenues

Oil and gas revenues for the years ended December 31, 2012 and 2011 were $9.2 million and $14.0 million, respectively. In 2012, we saw a significant decline in royalty revenues from our Louisiana BRP properties due to low gas prices and reduced drilling activity, which was offset in part by $1.1 million in royalty revenues received from our recently acquired Oklahoma properties. Included in revenue for the years ended 2012 and 2011 were bonus payments of $2.6 million and $2.1 million, respectively.

Other Operating Results

Processing and Transportation Revenues. We generated $5.0 million, $8.3 million and $13.5 million in processing revenues for the years ended December 31, 2013, 2012 and 2011, respectively. Our processing revenues are derived primarily from our ownership of coal preparation plants. We do not operate the preparation plants, but receive a fee for material processed through them. Similar to our coal royalty structure, the throughput fees are based on a percentage of the ultimate sales price for the material that is processed through the facilities.

During 2013 and 2012, lower volumes and prices at our plants in Appalachia resulted in lower revenues than in 2011. Also, during 2012 we sold a preparation plant midway through the year which also contributed to lower revenues in both 2013 and 2012.

In addition to our preparation plants, we own coal handling and transportation infrastructure in Illinois. In contrast to our typical royalty structure, we receive a fixed rate per ton for coal transported over these facilities. At the Williamson mine in Illinois, we operate the coal handling and transportation infrastructure and have subcontracted out that responsibility to a third party. We generated transportation fees from these assets of approximately $18.0 million, $19.5 million and $16.7 million for the years ended December 31, 2013, 2012 and 2011, respectively. The increase in transportation fees from 2011 to 2012 is due to increased volumes from our lessee operations ramping up in the Illinois Basin. During 2013, we saw reduced volumes on those transportation assets resulting in lower revenue.

Additional Revenues and Other Income. In addition to coal royalties, aggregate royalties, oil and gas revenues and processing and transportation revenues, we generated approximately 27%, 20% and 13% of our revenues from other sources for the years ended December 31, 2013, 2012 and 2011, respectively. These other sources include: income from equity and other unconsolidated investments, property taxes, minimums recognized as revenues, overriding royalties, timber, rentals, wheelage and other income. In 2013, the income from our equity investment in OCI Wyoming s trona mining and soda ash production business contributed $34.2 million to our revenues from other sources. In addition, we received $10.4 million from a right of way condemnation and recognized $8.3 million from minimums recognized as revenue with $3.5 million of that from our Macoupin lease. In 2012, we recognized $24.0 million from minimums recognized as revenue. Of the $24.0 million in 2012, we recognized $9.6 million on our Gatling Ohio lease and $8.2 million on our Macoupin lease. Also included in other revenue in 2012 is a gain from sale of assets of $13.6 million, including $8.5 million from the sale of a right of way for highway construction and $4.7 million from the sale of a preparation plant. 2011 revenues from other sources did not reflect any unusual transactions.

Operating expenses. Included in total expenses are:

Depreciation, depletion and amortization of $64.4 million, $58.2 million and $65.1 million for the years ended December 31, 2013, 2012 and 2011, respectively. The decrease in 2012 was primarily related to assets acquired from Gatling, LLC and Gatling Ohio, LLC that were impaired during the third and fourth quarters of 2011. The increase in 2013 is primarily due to increased oil and gas depletion and higher coal depletion due to the reserve swap that occurred in 2013 being at a higher per ton rate.

General and administrative expenses of $36.8 million, $29.7 million and $29.6 million for the years ended December 31, 2013, 2012 and 2011, respectively. General and administrative expenses are primarily impacted by accruals under our long-term incentive plan attributable to fluctuations in our unit price and additional personnel required to manage our properties. In 2013, we recorded increases in both long term incentive plan accruals and additional personnel over the two previous years.

Property, franchise and other taxes of $16.5 million, $17.7 million and $14.5 million for the years ended December 31, 2013, 2012 and 2011, respectively. A substantial portion of our property taxes is reimbursed to us by our lessees and is reflected as property tax revenue on our consolidated statements of comprehensive income.

Interest Expense. Interest expense was $64.4 million, $54.0 million and $49.2 million for the years ended December 31, 2013, 2012 and 2011, respectively. Interest increased due to additional debt incurred in 2013 and 2012 to fund acquisitions as well as a refinancing of our low-interest credit facility and payment on our low-interest term loan with 9.125% high yield notes.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Generally, we satisfy our working capital requirements with cash generated from operations. We finance our property acquisitions with available cash, borrowings under our revolving credit facility, and the issuance of our senior notes and additional common units. While our ability to satisfy our debt service obligations and pay distributions to our unitholders depends in large part on our future operating performance, our ability to make acquisitions will depend on prevailing economic conditions in the financial markets as well as the coal, oil and gas and aggregates/industrial minerals industries and other factors, some of which are beyond our control. For a more complete discussion of factors that will affect cash flow we generate from operations, see Item 1A, Risk Factors. Our capital expenditures, other than for acquisitions, have historically been minimal. However, we incur capital expenditures and operating expenses associated with the non-operated working interests in oil and gas assets. We finance those capital expenditures through a combination of cash flow from operations and borrowings under the NRP Oil and Gas revolving credit facility.

In September 2013, NRP, together with NRP Finance as co-issuer, sold $300.0 million of 9.125% Senior Notes due 2018 at an issue price of 99.007% of par value for net proceeds of $289 million. We used the net proceeds of the offering to repay all outstanding borrowings under Opco s revolving credit facility. Opco s revolving credit facility does not mature until August 2016 and, as of December 31, 2013, Opco had $280 million in available capacity under the facility. In August 2013, NRP Oil and Gas entered into a senior secured, reserve-based revolving credit facility with an initial $8.0 million borrowing base. The borrowing base was increased to $16.0 million in connection with the closing of the Sundance acquisition in December 2013. As of December 31, 2013, NRP Oil and Gas had the full $16.0 million available for borrowing under its revolving credit facility. As of the date of this filing, NRP Oil and Gas had $2.0 million of borrowings outstanding under its credit facility. We typically access the capital markets to refinance amounts outstanding under our revolving credit facilities as we approach the limits under those facilities, the timing of which depends on the pace and size of our acquisition program and development capital expenditures associated with our oil and gas business.

We refinanced a $35 million Opco senior note that matured in 2013, as well as $15 million of the remaining $52 million in principal payments due on Opco s senior notes during 2013. We have $81.0 million in principal payments on Opco s senior notes due in 2014. While we intend to reduce our leverage by paying the full amount with cash from operations, we may refinance some or all of these obligations as they come due.

We used $91.0 million of net proceeds from the September 2013 senior notes offering to repay principal on Opco s term loan. We also used a portion of the proceeds from the July 2013 $44.8 million special distribution from OCI Wyoming to repay $10.0 million of principal on Opco s term loan. Opco s next principal repayment obligation on the term loan is in January 2016, when Opco will be required to repay the remaining principal amount outstanding thereunder of $99.0 million.

In addition to the amounts available under our revolving credit facilities, we had $92.5 million in cash at December 31, 2013. We believe that the combination of our capacity under our revolving credit facilities and our cash on hand gives us enough liquidity to meet our current financial needs. Other than $81 million in principal repayments due on Opco s senior notes each year for the next several years, we do not have any debt maturing until 2016. In January 2014, our Board of Directors declared a cash distribution of $0.35 per unit with respect to the fourth quarter of 2013. The distribution represents a $0.20 (36%) decrease over the distribution declared and paid with respect to the third quarter of 2013. We believe that the distribution decrease will save NRP approximately $89.6 million annually and position NRP to reduce its debt over time while preserving its liquidity to pursue accretive acquisitions. Our debt covenant ratios are in compliance for both revolving credit facilities and Opco s outstanding senior notes. For a more complete discussion of factors that will affect our liquidity, see Item 1A, Risk Factors.

Net cash provided by operations for the years ended December 31, 2013, 2012 and 2011 was $247.1 million, $271.4 million and $305.6 million, respectively. The majority of our cash provided by operations is generated from coal royalty revenues and, beginning in 2013, our equity interest in OCI Wyoming.

Net cash used in investing activities for the years ended December 31, 2013, 2012 and 2011 was $302.8 million, $212.7 million and $115.1 million, respectively. Our 2013 investing activities consisted of the acquisitions of the interest in OCI Wyoming and the non-operated working interests in oil and gas properties located in the Williston Basin of North Dakota and Montana. During 2012, the majority of our investing activities consisted of acquiring reserves, plant and equipment and related intangibles as well as assets relating to

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Sugar Camp. These uses in 2012 were slightly offset by $24.8 million in proceeds from asset sales. During 2011, substantially all of our investing activities consisted of acquiring reserves, plant and equipment and other rights.

Net cash flows used in financing activities for the years ended December 31, 2013, 2012 and 2011 was $1.2 million, $124.2 million and $71.1 million, respectively. During 2013, 2012 and 2011 we had proceeds from loans of $567.0 million, $148.0 million and $385.0 million, respectively. During 2013, 2012 and 2011, these proceeds were offset by repayment of debt of $386.2 million, $30.8 million and $210.5 million, respectively. Also during 2013, 2012 and 2011 we paid cash distributions to our unitholders of $249.0 million, $240.8 million and $234.8 million, respectively. During 2013, we had net proceeds from an issuance of common units of $74.9 million, together with a capital contribution from our general partner of $1.5 million.

Contractual Obligations and Commercial Commitments

NRP Debt

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

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

NRP and NRP Finance have the option to redeem the notes, in whole or in part, at any time on or after April 1, 2016, at the redemption prices (expressed as percentages of principal amount) of 106.844% for the six-month period beginning on April 1, 2016, 104.563% for the twelve-month period beginning on October 1, 2016 and 100.000% beginning on October 1, 2017 and at any time thereafter, together with any accrued and unpaid interest to the date of redemption. In addition, before April 1, 2016, NRP and NRP Finance may redeem all or any part of the notes at a redemption price equal to the sum of the principal amount thereof, plus a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. Furthermore, before April 1, 2016, NRP and NRP Finance may on any one or more occasions redeem up to 35% of the aggregate principal amount of the notes with the net proceeds of certain public or private equity offerings at a redemption price of 109.125% of the principal amount of notes, plus any accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the aggregate principal amount of the notes issued under the indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. In the event of a change of control, as defined in the indenture, the holders of the notes may require NRP and NRP Finance to purchase their notes at a purchase price equal to 101% of the principal amount of the notes, plus accrued and unpaid interest, if any.

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

Opco Debt

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

- $20.0 million drawn under the floating rate revolving credit facility, due August 2016;
- $99.0 million floating rate term loan, due January 2016;
- $23.1 million of 4.91% senior notes due 2018;
- $128.6 million of 8.38% senior notes due 2019;
- $53.8 million of 5.05% senior notes due 2020;
- $1.5 million of 5.31% utility local improvement obligation due 2021;
- $27.0 million of 5.55% senior notes due 2023;
- $75.0 million of 4.73% senior notes due 2023;
- $165.0 million of 5.82% senior notes due 2024;
- $50.0 million of 8.92% senior notes due 2024;
- $175.0 million of 5.03% senior notes due 2026; and
- $50.0 million of 5.18% senior notes due 2026.

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

The senior note purchase agreement contains covenants requiring Opco to:

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

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

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

All of Opco s senior notes require annual principal payments in addition to semi-annual interest payments. The scheduled principal payments on Opco s 8.92% senior notes due in 2024 will begin in March 2014, and the scheduled principal payments on Opco s 4.73%, 5.03% and 5.18% senior notes will begin in December 2014. Opco also makes annual principal and interest payments on the utility local improvement obligation.

Revolving Credit Facility. As of the date of this report, Opco had $280 million in available borrowing capacity under its revolving credit facility. Under an accordion feature in the credit facility, Opco may request its lenders to increase their aggregate commitment to a maximum of $500 million on the same terms. However, Opco cannot be certain that its lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, Opco may elect to bring new lenders into the facility, but cannot make any assurance that the additional credit capacity will be available on existing or comparable terms.

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

	Quarter Ending			
	March 31	**June 30**	**September 30**	**December 31**
	(In thousands)			
Outstanding balance, beginning of period	$ 148,000	$ 148,000	$ 191,000	$
Borrowings under credit facility		43,000	7,000	20,000
Less: Repayments under credit facility			(198,000)	
Outstanding balance, ending period	$ 148,000	$ 191,000	$	$ 20,000

Opco s obligations under its credit facility are unsecured but are guaranteed by its subsidiaries. Opco may prepay all amounts outstanding under its credit facility at any time without penalty. Indebtedness under Opco s revolving credit facility bears interest, at our option, at either:

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

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

The Opco credit agreement contains covenants requiring Opco to maintain:

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

Term Loan. In connection with the OCI Wyoming acquisition, Opco entered into a 3-year, $200 million term loan facility in January 2013. The term loan facility is guaranteed by Opco s operating subsidiaries and bore interest at a weighted average rate of 2.43% in 2013. Interest on the term loan became payable initially in April 2013. We repaid $101 million of the term loan during 2013. The remaining balance of $99.0 million is due on January 23, 2016. The term loan facility contains financial covenants and other terms that are identical to those of our credit facility.

NRP Oil and Gas Debt

Revolving Credit Facility. In August 2013, NRP Oil and Gas entered into a 5-year, $100 million senior secured, reserve-based revolving credit facility in order to fund capital expenditure requirements related to the development of the oil and gas assets in which it owns non-operated working interests. The credit facility had an initial borrowing base of $8.0 million, which was increased to $16.0 million in connection with the closing of the Sundance acquisition in December 2013. The credit facility is secured by a first priority lien and security interest in substantially all of the assets of NRP Oil and Gas. NRP Oil and Gas is the sole obligor under its revolving credit facility, and neither NRP nor any of its other subsidiaries is a guarantor of such facility. As of December 31, 2013, NRP Oil and Gas did not have any borrowings outstanding under the credit facility and had the full $16.0 million available for borrowing thereunder. As of the date of this filing, NRP Oil and Gas had $2.0 million outstanding under the facility.

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

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

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

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

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

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.

OCI Wyoming Contingent Consideration Payment

In January 2013, we acquired non-controlling equity interests in OCI Wyoming Co. (OCI Co) and OCI Wyoming, L.P. (OCI LP), an operator of a trona mining and soda ash refining business. At the time of acquisition, (1) the acquired interests comprised a 48.51% general partner interest in OCI LP and 20% of the common stock and 100% of the preferred stock in OCI Co, (2) OCI Co owned a 1% limited partner interest in OCI LP and the right to receive a $14.5 million annual priority distribution and (3) 80% of the common stock in OCI Co was owned by OCI Chemical Corporation, and the remaining 50.49% general partner interest in OCI LP was owned by OCI Wyoming Holding Co., a subsidiary of OCI Chemical Corporation.

The three investments were acquired from Anadarko Holding Company (Anadarko) and its subsidiary, Big Island Trona Company for $292.5 million. The purchase price was funded from the proceeds of a $200 million term loan, $76.5 million in equity and GP interests issued in a private placement and the balance from operating cash. The acquisition agreement provides for a net present value of up to $50 million in cumulative additional contingent consideration payable by us should certain performance criteria be met at OCI LP as defined in the purchase and sale agreement in any of the years 2013, 2014 or 2015. At December 31, 2013, we accrued $15 million of contingent consideration that is included in Equity and other unconsolidated investments. The current portion of $0.7 million is included in Accounts payable and accrued liabilities and the long term portion of $14.3 million is included in Other non-current liabilities.

In July 2013, OCI LP was reorganized pursuant to a series of transactions in connection with an initial public offering by OCI Resources LP, an affiliate of OCI Chemical Corporation, of its interest in OCI LP. In connection with such reorganization, we exchanged our common stock and preferred stock in OCI Co for a limited partner interest in OCI LP, and OCI Resources LP became the owner of the limited partner interests in OCI LP that were previously owned by OCI Wyoming Holding Co. Following the reorganization, our interest in OCI LP increased to 49%, consisting of both limited and general partner interests. The restructuring did not have any impact on the operations, revenues, management or control of OCI LP.

With respect to the contingent consideration, in February 2014, Anadarko raised in oral discussions with us whether the reorganization transactions triggered an acceleration of our obligation to pay the additional contingent consideration in full. Although Anadarko has not made a formal claim against us, Anadarko has indicated that it may do so in the near future. We do not believe the reorganization transactions triggered an obligation to pay the additional contingent consideration, and we will continue to engage in discussions with Anadarko to resolve Anadarko s concerns. However, if Anadarko were to prevail on such a claim, we would be

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required to pay an amount to Anadarko in excess of the $15 million accrual described above up to the maximum amount of the additional contingent consideration. Any such additional amount would be considered to be additional acquisition consideration and added to Equity and other unconsolidated investments. We expect to pay any incremental amount with borrowings under our revolving credit facility or cash from operations. Any such borrowings and payments would reduce the amounts otherwise available to us for acquisitions and other opportunities.

Consolidated Debt

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2013 (in millions):

		Payments Due by Period					
Contractual Obligations	**Total**	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**
NRP:							
Long-term debt principal payments (including current maturities)(1)	$ 300.0	$	$	$	$	$ 300.0	$
Long-term debt interest payments(2)	137.9	28.3	27.4	27.4	27.4	27.4	
Opco:							
Long-term debt principal payments (including current maturities) (3)	868.0	81.0	81.0	200.0	81.0	81.0	344.0
Long-term debt interest payments(4)	230.4	43.5	38.4	33.3	28.2	23.2	63.8
Rental leases(5)	3.4	0.7	0.7	0.7	0.7	0.6	
Total	$ 1,539.7	$ 153.5	$ 147.5	$ 261.4	$ 137.3	$ 432.2	$ 407.8

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

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

(3) The amounts indicated in the table include principal due on Opco s senior notes, as well as the utility local improvement obligation related to our property in DuPont, Washington. On January 24, 2013, Opco entered into a $200 million three year term loan. As of December 31, 2013, there was $99.0 million outstanding which is due in January 2016.

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

(5) On January 1, 2009, Opco entered into a ten-year lease agreement for the rental of office space from Western Pocahontas Properties Limited Partnership for $0.6 million per year. In addition, BRP leases office space for approximately $100,000 per year. These rental obligations are included in the table above.

Shelf Registration Statements and At-the-Market Program

On April 24, 2012 we filed an automatically effective shelf registration statement on Form S-3 with the SEC that is available for registered offerings of common units and debt securities. This shelf replaced our previous shelf registration statement, which expired at the end of February 2012.

On August 15, 2012, we filed a shelf registration statement on Form S-3 that registered all of the common units held by Adena Minerals. This shelf registration statement was declared effective by the SEC on September 21, 2012. Following the effectiveness of this registration statement, Adena distributed 15,181,716 common units to its shareholders, and we subsequently filed prospectus supplements to register the resale of these common units by those shareholders. The shelf registration statement filed in August 2012 also registered up to $500 million in equity securities of NRP. On November 12, 2013, we filed a prospectus supplement and entered into an Equity Distribution Agreement relating to the offer and sale from time to time of common units having an aggregate offering price of $75 million through one or more managers acting as sales agents at prices to be agreed upon at the time of sale. Under the terms of the Equity Distribution Agreement, we may also sell common units from time to time to any manager as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to any manager as principal would be pursuant to the terms of a separate terms agreement between NRP and such manager. Sales of common units in this at-the-market (ATM) program will be made pursuant to the shelf registration statement declared effective in September 2012. We did not sell any units under the ATM program in 2013.

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

We cannot control the resale of the common units by any of the selling unitholders under the shelf registration statements described above, and the amounts, prices and timing of the issuance and sale of any equity or debt securities by NRP will depend on market conditions, our capital requirements and compliance with our credit facilities, term loan and senior notes.

Off-Balance Sheet Transactions

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

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on operations for the years ended December 31, 2013, 2012 and 2011.

Environmental

The operations our lessees conduct on our properties, as well as the aggregates/industrial minerals and oil and gas operations in which we have interests, are subject to federal and state environmental laws and regulations. See Item 1, Business Regulation and Environmental Matters. As an owner of surface interests in some properties, we may be liable for certain environmental conditions occurring on the surface properties. The terms of substantially all of our coal leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify us against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. Because we have no employees, employees of Western Pocahontas Properties Limited Partnership make regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. We believe that our lessees will be able to comply with existing regulations and do not expect any lessee s failure to comply with environmental laws and regulations to have a material impact on our financial condition or results of operations. We have neither incurred, nor are aware of, any material environmental charges imposed on us related to our properties for the period ended December 31, 2013. We are not associated with any environmental contamination that may require remediation costs. However, our lessees do conduct reclamation work on the properties under lease to them. Because we are not the permittee of the mines being reclaimed, we are not responsible for the costs associated with these reclamation operations. In addition, West Virginia has established a fund to satisfy any shortfall in reclamation obligations. As an owner of working interests in oil and natural gas operations, we are responsible for our proportionate share of any losses and liabilities, including environmental liabilities, arising from uninsured and underinsured events.

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The electric utility industry, which is the most significant end-user of domestic coal, is subject to extensive regulation regarding the environmental impact of its power generation activities. On January 8, 2014, EPA published proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. President Obama has directed EPA to issue proposed regulations on existing fossil fuel-fired power plants in June 2014. We expect that EPA s proposed regulations for both new and existing power plants will negatively affect the viability of coal-fired power generation, which will ultimately reduce coal consumption and the production of coal from our properties.

Related Party Transactions

Partnership Agreement

Our general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with the partnership agreement, we reimburse our general partner and its affiliates for expenses incurred on our behalf. All direct general and administrative expenses are charged to us as incurred. We also reimburse indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by our general partner and its affiliates.

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

	For the Years Ended December 31,		
	2013	2012	2011
		(In thousands)	
Reimbursement for services	$ 11,480	$ 9,791	$ 9,136

For additional information, see Item 13, Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement.

Transactions with Cline Affiliates

Various companies controlled by Chris Cline, including Foresight Energy, lease coal reserves from NRP, and we provide coal transportation services to them for a fee. Mr. Cline, both individually and through affiliated companies, owns a 31% interest in our general partner, as well as 4,917,548 common units, at the time of this filing. At December 31, 2013, we had accounts receivable totaling $7.7 million from Cline affiliates. In addition, the overriding royalty and the lease of the loadout facility at the Sugar Camp mine are classified as contracts receivable of $51.7 million on our Consolidated Balance Sheets. Revenues from the Cline affiliates are as follows:

	For The Years Ended December 31,		
	2013	2012	2011
		(In thousands)	
Coal royalty revenues	$ 54,322	$ 48,567	$ 42,474
Processing fees	1,281	2,409	2,975
Transportation fees	17,977	19,514	16,689
Minimums recognized as revenue	3,477	17,785	
Override revenue	3,226	4,066	2,691
Other revenue	8,149		2,990
	$ 88,432	$ 92,341	$ 67,819

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As of December 31, 2013, we had received $71.4 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $20.0 million was received in 2013.

We recognized an asset impairment of $90.9 million during the third quarter of 2011 related to certain of our assets at the Gatling West Virginia location and $70.4 million during the fourth quarter of 2011 related to the Gatling Ohio location. During the fourth quarter of 2012, we recognized an additional impairment of $2.6 million related to the assets at the Gatling West Virginia location.

During 2013 and 2011, we recognized non-cash gains of $8.1 million and $3.0 million on reserve exchanges in Illinois with Williamson Energy. The tons received during 2013 were fully mined during 2013 and the tons received during 2011 were fully mined in 2012, while the tons exchanged are not included in the current mine plans. The gains are included in Other revenues on the Consolidated Statement of Comprehensive Income.

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd., which controls several private equity funds focused on investments in the energy business. In connection with the formation of Quintana Capital, the Partnership adopted a formal conflicts policy that establishes the opportunities that will be pursued by NRP and those that will be pursued by Quintana Capital. The governance documents of Quintana Capital s affiliated investment funds reflect the guidelines set forth in NRP s conflicts policy. See Item 13, Certain Relationships and Related Transactions, and Director Independence Quintana Capital Group GP, Ltd.

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

For the years ended December 31, 2013, 2012 and 2011, the revenues from Taggart were as follows:

	For the Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Processing revenue	$ 1,761	$ 5,580	$ 9,755

During the third quarter of 2012, we sold a preparation plant back to Taggart Global for $12.3 million. We received $10.5 million in cash and a note receivable from Taggart, payable over three years for the balance. We recorded a gain of $4.7 million included in Other income of the Consolidated Statements of Income for the third quarter of 2012. The net book value of the asset sold was $7.6 million. During 2013, Taggart was sold to Forge and the note receivable that we held was paid in full.

At December 31, 2013, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp., a coal mining company traded on the TSX Venture Exchange that is one of our lessees in Tennessee. Corbin J. Robertson III, one of our directors, is Chairman of the Board of Corsa. Revenues from Corsa are as follows:

	For the Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Coal royalty revenues	$ 4,594	$ 3,486	$ 1,629

NRP also had accounts receivable totaling $0.3 million from Corsa at December 31, 2013.

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Office Building in Huntington, West Virginia

We lease an office building in Huntington, West Virginia from Western Pocahontas at market rates. The terms of the lease were approved by our Conflicts Committee. We pay $0.6 million each year in lease payments.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

We are exposed to market risk, which includes adverse changes in commodity prices and interest rates.

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.

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

Interest Rate Risk

Our exposure to changes in interest rates results from borrowings under our credit facility, which are subject to variable interest rates based upon LIBOR or the federal funds rate plus an applicable margin. Management monitors interest rates and may enter into interest rate instruments to protect against increased borrowing costs. At December 31, 2013, we had $119 million outstanding in variable interest debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $1.2 million, assuming the same principal amount remained outstanding during the year.

Item 8. ***Financial Statements and Supplementary Data***

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NATURAL RESOURCE PARTNERS L.P.

CONSOLDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners of Natural Resource Partners L.P.

We have audited the accompanying consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2013 and 2012, and the related consolidated statements of comprehensive income, partners capital, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of OCI Wyoming LP (OCI Wyoming) (a Limited Partnership in which Natural Resource Partners LP owns a 49% interest). Natural Resource Partners LP s investment in OCI Wyoming constituted approximately $269 million of Natural Resource Partners LP s assets as of December 31, 2013 and Natural Resource Partners LP s equity in the net income of OCI Wyoming constituted approximately $34 million of Natural Resource Partners LP s Net Income for the period ended December 31, 2013. OCI Wyoming s financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for OCI Wyoming, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Natural Resource Partners L.P. at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Natural Resource Partners L.P. s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission 1992 framework and our report dated February 28, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 28, 2014

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands, except for unit information)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 92,513	$ 149,424
Accounts receivable, net of allowance for doubtful accounts	33,737	35,116
Accounts receivable affiliates	7,666	10,613
Other	1,691	1,042
Total current assets	135,607	196,195
Land	24,340	24,340
Plant and equipment, net	26,435	32,401
Mineral rights, net	1,405,455	1,380,473
Intangible assets, net	66,950	70,766
Equity and other unconsolidated investments	269,338	
Loan financing costs, net	11,502	4,291
Long-term contracts receivable affiliates	51,732	55,576
Other assets	497	630
Total assets	$ 1,991,856	$ 1,764,672
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 8,659	$ 3,693
Accounts payable affiliates	391	957
Current portion of long-term debt	80,983	87,230
Accrued incentive plan expenses current portion	8,341	7,718
Property, franchise and other taxes payable	7,830	7,952
Accrued interest	17,184	10,265
Total current liabilities	123,388	117,815
Deferred revenue	142,586	123,506
Accrued incentive plan expenses	10,526	8,865
Other non-current liabilities	14,341	
Long-term debt	1,084,226	897,039
Partners capital:		
Common units outstanding: (109,812,408 and 106,027,836)	606,774	605,019
General partner s interest	10,069	10,026
Non-controlling interest	324	2,845
Accumulated other comprehensive loss	(378)	(443)
Total partners capital	616,789	617,447
Total liabilities and partners capital	$ 1,991,856	$ 1,764,672

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

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In thousands, except per unit data)

	For the Years Ended December 31,		
	2013	2012	2011
Revenues:			
Coal royalties	$ 212,663	$ 260,734	$ 279,221
Equity and other unconsolidated investment income	34,186		
Aggregate royalties	7,643	6,598	6,734
Processing fees	5,049	8,299	13,475
Transportation fees	17,977	19,513	16,688
Oil and gas revenues	17,080	9,160	14,017
Property taxes	15,416	15,273	12,640
Minimums recognized as revenue	8,285	23,956	9,148
Override royalties	13,499	15,527	14,523
Other	26,319	20,087	11,237
Total revenues and other income	358,117	379,147	377,683
Operating expenses:			
Depreciation, depletion and amortization	64,377	58,221	65,118
Asset impairments	734	2,568	161,336
General and administrative	36,821	29,714	29,553
Property, franchise and other taxes	16,463	17,678	14,486
Oil and gas lease operating expenses	739		
Transportation costs	1,644	1,944	2,033
Coal royalty and override payments	1,103	1,857	1,022
Total operating expenses	121,881	111,982	273,548
Income from operations	236,236	267,165	104,135
Other income (expense)			
Interest expense	(64,396)	(53,972)	(49,180)
Interest income	238	162	69
Income before non-controlling interest	172,078	213,355	55,024
Non-controlling interest			(998)
Net income	$ 172,078	$ 213,355	$ 54,026
Net income attributable to:			
General partner	$ 3,442	$ 4,267	$ 1,081
Limited partners	$ 168,636	$ 209,088	$ 52,945
Basic and diluted net income per limited partner unit	$ 1.54	$ 1.97	$ 0.50
Weighted average number of common units outstanding	109,584	106,028	106,028
Comprehensive income	$ 172,143	$ 213,405	$ 54,079

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

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(In thousands, except unit data)

	Common Units		General Partner	Non-Controlling Interest	Accumulated Other Comprehensive Income (Loss)	
	Units	Amounts	Amounts	Amounts		Total
Balance at December 31, 2010	106,027,836	$ 806,529	$ 14,132	$ 5,065	$ (546)	$ 825,180
Distributions		(230,080)	(4,696)	(52)		(234,828)
Non-controlling interest adjustment				(373)		(373)
Costs associated with equity transactions		(141)				(141)
Non-controlling interest				998		998
Net income for the year ended December 31, 2011		52,945	1,081			54,026
Loss on interest hedge					53	53
Comprehensive income					53	54,079
Balance at December 31, 2011	106,027,836	$ 629,253	$ 10,517	$ 5,638	$ (493)	$ 644,915
Distributions		(233,263)	(4,758)	(2,793)		(240,814)
Costs associated with equity transactions		(59)				(59)
Net income for the year ended December 31, 2012		209,088	4,267			213,355
Loss on interest hedge					50	50
Comprehensive income					50	213,405
Balance at December 31, 2012	106,027,836	$ 605,019	$ 10,026	$ 2,845	$ (443)	$ 617,447
Issuance of common units	3,784,572	75,000				75,000
Capital contribution			1,531			1,531
Cost associated with equity transactions		(293)				(293)
Distributions		(241,588)	(4,930)	(2,521)		(249,039)
Net income for the year ended December 31, 2013		168,636	3,442			172,078
Interest rate swap from unconsolidated investments					13	13
Loss on interest hedge					52	52
Comprehensive income					65	172,143
Balance at December 31, 2013	109,812,408	$ 606,774	$ 10,069	$ 324	$ (378)	$ 616,789

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

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities:			
Net income	$ 172,078	$ 213,355	$ 54,026
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	64,377	58,221	65,118
Non-cash interest charge	2,200	605	625
Non-cash gain on reserve swap	(8,149)		(2,990)
Equity and other unconsolidated investment income	(34,186)		
Distributions of earnings from unconsolidated investments	24,113		
Gain on sale of assets	(10,921)	(13,575)	(1,058)
Asset impairment	734	2,568	161,336
Non-controlling interest			998
Change in operating assets and liabilities:			
Accounts receivable	6,826	(802)	(6,951)
Other assets	(516)	(236)	90
Accounts payable and accrued liabilities	2,197	1,909	854
Accrued interest	6,919	(496)	950
Deferred revenue	19,240	11,684	31,277
Accrued incentive plan expenses	2,284	(3,461)	1,909
Property, franchise and other taxes payable	(122)	1,636	(610)
Net cash provided by operating activities	247,074	271,408	305,574
Cash flows from investing activities:			
Acquisition of land, coal, other mineral rights and related intangibles	(72,000)	(180,534)	(120,284)
Acquisition of equity interests	(293,085)		
Distributions from unconsolidated investments	48,833		
Acquisition or construction of plant and equipment		(681)	(404)
Proceeds from sale of assets	10,929	24,822	5,600
Return on direct financing lease and contractual override	2,558	2,669	
Investment in direct financing lease		(59,009)	
Net cash used in investing activities	(302,765)	(212,733)	(115,088)
Cash flows from financing activities:			
Proceeds from loans	567,020	148,000	385,000
Proceeds from issuance of common units	75,000		
Deferred financing costs	(9,209)		(2,957)
Repayments of loans	(386,230)	(30,800)	(210,519)
Payment of obligation related to acquisitions		(500)	(7,625)
Costs associated with equity transactions	(293)	(59)	(141)
Distributions	(249,039)	(240,814)	(234,828)
Capital contribution by general partner	1,531		
Net cash used in financing activities	(1,220)	(124,173)	(71,070)
Net increase (decrease) in cash and cash equivalents	(56,911)	(65,498)	119,416
Cash and cash equivalents at beginning of period	149,424	214,922	95,506
Cash and cash equivalents at end of period	$ 92,513	$ 149,424	$ 214,922

Supplemental cash flow information:			
Cash paid during the period for interest	$ 55,191	$ 53,842	$ 47,653
Non-cash investing activities:			
Non-controlling interest			$ 373
Note receivable related to sale of assets		$ 1,808	
Non-cash contingent consideration on equity investments	$ 15,000		
Non-cash financing activities:			
Purchase obligation related to reserve and infrastructure acquisitions			$ 500

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

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NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Organization

Natural Resource Partners L.P. (the Partnership), a Delaware limited partnership, was formed in April 2002. The general partner of the Partnership is NRP (GP) LP (NRP GP), a Delaware limited partnership, whose general partner is GP Natural Resource Partners LLC, a Delaware limited liability company. The Partnership engages principally in the business of owning and managing mineral properties in the United States. The Partnership owns coal reserves in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. As of December 31, 2013, the Partnership owned or controlled approximately 2.3 billion tons of proven and probable coal reserves (unaudited), and also owned approximately 500 million tons of aggregate reserves (unaudited) in a number of states across the country. The Partnership does not operate any mines, but leases reserves to experienced mine operators under long-term leases that grant the operators the right to mine reserves in exchange for royalty payments. Lessees are generally required to make royalty payments based on the higher of a percentage of the gross sales price or a fixed price per ton, in addition to a minimum payment.

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

The Partnership s operations are conducted through, and its operating assets are owned by, its subsidiaries. The Partnership owns its subsidiaries through two wholly owned operating companies, NRP (Operating) LLC and NRP Oil and Gas LLC. NRP GP has sole responsibility for conducting its business and for managing its operations. Because NRP GP is a limited partnership, its general partner, GP Natural Resource Partners LLC, conducts its business and operations, and the board of directors and officers of GP Natural Resource Partners LLC makes decisions on its behalf. Robertson Coal Management LLC, a limited liability company wholly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. Mr. Robertson is entitled to nominate all ten of the directors, five of whom must be independent directors, to the board of directors of GP Natural Resource Partners LLC. Mr. Robertson has delegated the right to nominate two of the directors, one of whom must be independent, to Adena Minerals, LLC, an affiliate of Christopher Cline.

2. Summary of Significant Accounting Policies

Principles of Consolidation

The financial statements include the accounts of Natural Resource Partners L.P. and its wholly owned subsidiaries as well as BRP LLC, a venture with International Paper Company controlled by the Partnership. Intercompany transactions and balances have been eliminated.

Business Combinations

For purchase acquisitions accounted for as a business combination, the Partnership is required to record the assets acquired, including identified intangible assets and liabilities assumed at their fair value, which in many instances involves estimates based on third party valuations, such as appraisals, or internal valuations based on discounted cash flow analyses or other valuation techniques.

Use of Estimates

Preparation of the accompanying financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in the accompanying Consolidated Balance Sheets and the reported amounts of revenues and expenses in the accompanying Consolidated Statements of Comprehensive Income during the reporting period. Actual results could differ from those estimates.

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Fair Value

The Partnership discloses certain assets and liabilities using fair value as defined by authoritative guidance. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. See Note 11. Fair Value Measurements.

There are three levels of inputs that may be used to measure fair value:

Level 1 Quoted prices in active markets for identical assets or liabilities.

Level 2 Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. Level 3 assets and liabilities include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation.

Cash Equivalents and Restricted Cash

The Partnership considers all highly liquid short-term investments with an original maturity of three months or less to be cash equivalents.

Accounts Receivable

Accounts receivable from the Partnership s lessees do not bear interest. Receivables are recorded net of the allowance for doubtful accounts in the accompanying Consolidated Balance Sheets. The Partnership evaluates the collectability of its accounts receivable based on a combination of factors. The Partnership regularly analyzes its lessees accounts and when it becomes aware of a specific customer s inability to meet its financial obligations to the Partnership, such as in the case of bankruptcy filings or deterioration in the lessee s operating results or financial position, the Partnership records a specific reserve for bad debt to reduce the related receivable to the amount it reasonably believes is collectible. Accounts are charged off when collection efforts are complete and future recovery is doubtful. If circumstances related to specific lessees change, the Partnership s estimates of the recoverability of receivables could be further adjusted.

Equity Investments

The Partnership accounts for non-marketable investments using the equity method of accounting if the investment gives it the ability to exercise significant influence over, but not control of, an investee. Significant influence generally exists if the Partnership has an ownership interest representing between 20% and 50% of the voting stock of the investee.

Under the equity method of accounting, investments are stated at initial cost and are adjusted for subsequent additional investment and the proportionate share of earnings or losses and distributions. The basis difference between the investment and the proportional share of the fair value of the underlying net assets of equity method investees is hypothetically allocated first to identified tangible assets and liabilities, finite-lived intangibles or indefinite-lived intangibles and the balance is attributed to goodwill. The portion of the basis difference attributed to net tangible assets and finite-lived intangibles is amortized over their estimated useful life while indefinite-lived intangibles, if any, and goodwill is not amortized. The amortization of the basis difference is recorded as a reduction of earnings from the equity investment in the Consolidated Statements of Comprehensive Income.

An investee s accounts are not included in the Partnership s Consolidated Balance Sheets and Statements of Comprehensive Income. However, the Partnership s carrying value in an equity method investee company is reflected in the caption Equity and other unconsolidated investments in the Partnership s Consolidated Balance Sheets. The Partnership s adjusted share of the earnings or losses of the investee company is reflected in the

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Consolidated Statements of Comprehensive Income as revenues and other income under the caption Equity and other unconsolidated investment income. These earnings are generated from natural resources, which are considered part of the Partnership s core business activities consistent with its directly owned revenue generating activities. Investee earnings are adjusted to reflect the amortization of any difference between the cost basis of the equity investment and the proportionate share of the investee s book value, which has been allocated to the fair value of net identified tangible and finite-lived intangible assets and amortized over the estimated lives of those assets.

The Partnership evaluates its equity investments for impairment when events or changes in circumstances indicate, in management s judgment, that the carrying value of such investment may have experienced an other than temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment loss. The fair value of the impaired investment is based on quoted market prices, or upon the present value of expected cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. No impairment losses have been recognized as of December 31, 2013.

Land and Mineral Rights

Land and mineral rights owned and leased are recorded using the FASB s business combination and asset purchase authoritative guidance. Coal and aggregate mineral rights are depleted on a unit-of-production basis by lease, based upon minerals mined in relation to the net cost of the mineral properties and estimated proven and probable tonnage therein, or over the amortization period of the lease. The Partnership owns royalty and non-operated working interests in oil and natural gas minerals, all of which are located in the U.S. The Partnership does not determine whether or when to develop reserves. The Partnership uses the successful efforts method to account for its working interest in oil and gas properties. Oil and gas non-operated working interests are depleted on a unit-of-production basis. The depletion rate is adjusted annually based upon the amount of remaining reserves as determined by independent third party petroleum engineers. Oil and gas royalty interests are depleted on a straight-line basis over 30 years or the life of the lease, whichever is shorter.

Plant and Equipment

Plant and equipment consists of coal preparation plants, related coal handling facilities, and other coal and aggregate processing and transportation infrastructure. Expenditures for new facilities and expenditures that substantially increase the useful life of property, including interest during construction, are capitalized and reported in the Consolidated Statements of Cash Flows. These assets are recorded at cost and are depreciated on a straight-line basis over their useful lives, which when originally recorded range from three to twenty years.

Intangible Assets

The Partnership s intangible assets consist of above-market contracts. Intangible assets are identified related to contracts acquired when compared to the estimate of current market rates for similar contracts. The estimated fair value of the above-market rate contracts are determined based on the present value of future cash flow projections related to the underlying assets acquired. Intangible assets are amortized on a unit-of-production basis except that a minimum amortization is calculated on a straight line basis for temporarily idled assets.

Deferred Financing Costs

Deferred financing costs consist of legal and other costs related to the issuance of the Partnership s revolving credit facility and senior notes. These costs are amortized over the term of the debt.

Asset Impairment

A long term asset is deemed impaired in most cases when the future expected cash flow from its use and disposition is less than its book value. Impairment is measured based on the present value of the projected future cash flow compared to current book value. The Partnership has developed procedures to periodically evaluate its long-lived assets for possible impairment. These procedures are performed throughout the year and are based on historic, current and future performance and are designed to be early warning tests. If an asset fails one of the early warning tests, additional evaluation is performed for that asset that considers both quantitative and qualitative information. Undiscounted cash flow is used to evaluate recoverability with any adjustment to fair value to reflect impairment based on discounted cash flows. 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 a separate impairment evaluation be completed on a significant property. As a result of the continued weakness in the coal markets, the Partnership intends to closely monitor its coal assets impairment risk, and the impairment evaluation process may be completed more frequently if deemed necessary by the Partnership. Future impairment analyses could result in downward adjustments to the carrying value of the Partnership s assets. See Note 6. Asset Impairments.

Revenues

Coal and Aggregate Royalties. Coal and aggregate royalty revenues are recognized on the basis of tons of mineral sold by the Partnership s lessees and the corresponding revenue from those sales. Generally, the lessees make payments to the Partnership based on the greater of a percentage of the gross sales price or a fixed price per ton of mineral they sell.

Processing and Transportation Fees. Processing fees are recognized on the basis of tons of material processed through the facilities by the Partnership s lessees and the corresponding revenue from those sales. Generally, the lessees of the processing facilities make payments to the Partnership based on the greater of a percentage of the gross sales price or a fixed price per ton of material that is processed and sold from the facilities. The processing leases are structured in a manner so that the lessees are responsible for operating and maintenance expenses associated with the facilities. Transportation fees are recognized on the basis of tons of material transported over the beltlines. Under the terms of the transportation contracts, the Partnership receives a fixed price per ton for all material transported on the beltlines.

Oil and Gas Revenues. Oil and gas royalty revenues are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. Generally, the lessees make payments based on a percentage of the selling price. Also, included within oil and gas royalties are lease bonus payments, which are generally paid upon the execution of a lease. Some leases are subject to minimum annual payments or delay rentals. Revenues related to the Partnership s non-operated working interests in oil and gas assets are recognized on the basis of our net revenue interests in hydrocarbons produced. The Partnership also has capital expenditure and operating expenditure obligations associated with the non-operated working interests. The Partnership s revenues fluctuate based on changes in the market prices for oil and natural gas, the decline in production from producing wells, and other factors affecting the third-party oil and natural gas exploration and production companies that operate wells, including the cost of development and production.

Minimum Royalties. Most of the Partnership s lessees must make minimum annual or quarterly payments which are generally recoupable over certain time periods. These minimum payments are recorded as deferred revenue when received. The deferred revenue attributable to the minimum payment is recognized as royalty revenue when the lessee recoups the minimum payment through production. The deferred revenue is recognized as minimums recognized as revenue in the period immediately following the expiration of the lessee s ability to recoup the payments.

Lessee Audits and Inspections

The Partnership periodically audits lessee information by examining certain records and internal reports of its lessees. The Partnership s regional managers also perform periodic mine inspections to verify that the information that has been reported to the Partnership is accurate. The audit and inspection processes are designed to identify material variances from lease terms as well as differences between the information reported to the Partnership and the actual results from each property. Audits and inspections, however, are in periods subsequent to when the revenue is reported and any adjustment identified by these processes might be in a reporting period different from when the revenue was initially recorded. Typically there are no material adjustments from this process.

Property Taxes

The Partnership is responsible for paying property taxes on the properties it owns. Typically, the lessees are contractually responsible for reimbursing the Partnership for property taxes on the leased properties. The reimbursement of property taxes is included in property tax revenue in the Consolidated Statements of Comprehensive Income.

Income Taxes

No provision for income taxes related to the operations of the Partnership has been included in the accompanying financial statements because, as a partnership, it is not subject to federal or material state income taxes and the tax effect of its activities accrues to the unitholders. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities. In the event of an examination of the Partnership s tax return, the tax liability of the partners could be changed if an adjustment in the Partnership s income is ultimately sustained by the taxing authorities.

Share-Based Payment

The Partnership accounts for awards relating to its Long-Term Incentive Plan using the fair value method, which requires the Partnership to estimate the fair value of the grant, and charge or credit the estimated fair value to expense over the service or vesting period of the grant based on fluctuations in the Partnership s common unit price. In addition, estimated forfeitures are included in the periodic computation of the fair value of the liability and the fair value is recalculated at each reporting date over the service or vesting period of the grant.

New Accounting Standards

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

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

3. Significant Acquisitions

Sundance. On December 19, 2013, the Partnership completed the acquisition of non-operated working interests in the Williston Basin of North Dakota from Sundance Energy, Inc. The Partnership accounted for the transaction in accordance with the authoritative guidance for business combinations. The identification of all assets acquired and liabilities assumed as well as the valuation process required for the allocation of the purchase price is not complete. Pending the final purchase price adjustments and allocation, the assets acquired for approximately $33.7 million are included in mineral rights in the accompanying Consolidated Balance Sheets.

Abraxas. On August 9, 2013, the Partnership completed the acquisition of non-operated working interests in the Williston Basin of North Dakota and Montana from Abraxas Petroleum. The Partnership accounted for the

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transaction in accordance with the authoritative guidance for business combinations. The identification of all assets acquired and liabilities assumed as well as the valuation process required for the allocation of the purchase price is not complete. Pending the final purchase price adjustments and allocation, the assets acquired for approximately $38.3 million are included in mineral rights in the accompanying Consolidated Balance Sheets. Revenues and costs from the working interests for 2013 of $4.6 million and $2.2 million, respectively, are included from June 17, 2013, the effective date of acquisition.

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

Colt. In September 2009, the Partnership signed a definitive agreement to acquire approximately 200 million tons of coal reserves related to the Deer Run Mine in Illinois from Colt, LLC, an affiliate of Foresight Energy, through several separate transactions for a total purchase price of $255 million. During the year ended December 31, 2012, the Partnership paid $80.0 million to complete the acquisition of reserves at this mine.

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

Sugar Camp. In March 2012, the Partnership acquired from Sugar Camp Energy, an affiliate of Foresight Energy, the rail loadout and associated infrastructure assets at the Sugar Camp mine in Illinois for total consideration of $50.0 million. At the time of the acquisition, the Partnership also entered into a lease agreement related to the rail loadout and associated facilities that has been accounted for as a direct financing lease. The lease provides for payments based upon tons of coal transported over the facilities subject to quarterly recoupable minimum payments of $1.25 million. The lease is for a term of 20 years but may be extended by the lessee. Total projected remaining payments under the lease at December 31, 2013 are $91.2 million with unearned income of $42.8 million. The unearned income will be reflected as transportation fees over the term of the lease using the effective interest method. Any amounts in excess of the contractual minimums will be recorded as transportation fees when earned. The net amount receivable under the lease as of December 31, 2013 was $48.5 million, of which $1.6 million is included in accounts receivable affiliates while the remaining is included in long-term contracts receivable affiliate. The Partnership recognized $5.1 million in transportation fees during the year ended December 31, 2013 related to this lease.

In a separate transaction, the Partnership acquired, from Ruger, LLC, an affiliate of Foresight Energy, a contractual overriding royalty interest for $8.9 million that will provide for payments based upon production from specific tons at the Sugar Camp operations. This overriding royalty was accounted for as a financing arrangement and is reflected as an affiliate receivable. The payments the Partnership receives with respect to the overriding royalty will be reflected partially as a return of the initial investment and partially as override revenue over the life of the contract using the effective interest method based upon actual production and adjusted periodically for differences in projected and actual production. The net amount receivable under the agreement as of December 31, 2013 was $6.1 million of which $1.2 million is included in accounts receivable affiliates while the remaining is included in long-term contracts receivable affiliate. The Partnership recognized $1.3 million in overriding royalty during the year ended December 31, 2013 related to the contractual overriding royalty interest.

4. Equity and Other Investments

In January 2013, the Partnership acquired non-controlling equity interests in OCI Wyoming Co. (OCI Co) and OCI Wyoming, L.P. (OCI LP), an operator of a trona mining and soda ash refinery business. At the time of acquisition, (1) the acquired interests comprised a 48.51% general partner interest in OCI LP and 20% of the common stock and 100% of the preferred stock in OCI Co, (2) OCI Co owned a 1% limited partner interest in OCI LP and the right to receive a $14.5 million annual priority distribution and (3) 80% of the common stock in OCI Co was owned by OCI Chemical Corporation, and the remaining 50.49% general partner interest in OCI LP was owned by OCI Wyoming Holding Co., a subsidiary of OCI Chemical Corporation.

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The three investments were acquired from Anadarko Holding Company (Anadarko) and its subsidiary, Big Island Trona Company for $292.5 million. The purchase price was funded from the proceeds of a $200 million term loan, $76.5 million in equity and GP interests issued in a private placement and the balance from operating cash. The acquisition agreement provides for a net present value of up to $50 million in cumulative additional contingent consideration payable by the Partnership should certain performance criteria be met at OCI LP as defined in the purchase and sale agreement in any of the years 2013, 2014 or 2015. At December 31, 2013, the Partnership accrued $15 million of contingent consideration that is included in Equity and other unconsolidated investments. The current portion of $0.7 million is included in Accounts payable and accrued liabilities and the long term portion of $14.3 million is included in Other non-current liabilities.

In July 2013, OCI LP was reorganized pursuant to a series of transactions in connection with an initial public offering by OCI Resources LP, an affiliate of OCI Chemical Corporation, of its interest in OCI LP. In connection with such reorganization, the Partnership exchanged its common stock and preferred stock in OCI Co for a limited partner interest in OCI LP, and OCI Resources LP became the owner of the limited partner interests in OCI LP that were previously owned by OCI Wyoming Holding Co. Following the reorganization, the Partnership s interest in OCI LP increased to 49%, consisting of both limited and general partner interests. The restructuring did not have any impact on the operations, revenues, management or control of OCI LP.

With respect to the contingent consideration, in February 2014, Anadarko raised in oral discussions with the Partnership whether the reorganization transactions triggered an acceleration of the Partnership s obligation to pay the additional contingent consideration in full. Although Anadarko has not made a formal claim against the Partnership, Anadarko has indicated that it may do so in the near future. The Partnership does not believe the reorganization transactions triggered an obligation to pay the additional contingent consideration, and the Partnership will continue to engage in discussions with Anadarko to resolve Anadarko s concerns. However, if Anadarko were to prevail on such a claim, the Partnership would be required to pay an amount to Anadarko in excess of the $15 million accrual described above up to the maximum amount of the additional contingent consideration. Any such additional amount would be considered to be additional acquisition consideration and added to Equity and other unconsolidated investments.

The Partnership engaged a valuation specialist to assist in identifying and valuing the assets and liabilities of OCI Wyoming at the date of acquisition, including the land, mine, plant and equipment as well as identifiable intangible assets. Included in fair value adjustments, is an increase in the Partnership s proportionate fair value of property, plant and equipment of $58.0 million, which will be depreciated using the straight-line method over a weighted average life of 28 years. Also, $133.0 million has been assigned to a right to mine asset which will be amortized using the units of production method. Under the equity method of accounting, these amount are not reflected individually in the accompanying consolidated financial statements but are used to determine periodic charges to amounts reflected as income earned from the equity investments. For the year ended December 31, 2013, amortization of basis difference of $2.9 million was recorded by the Partnership.

The following summarized financial information as of December 31, 2013 and the results of operations for the year then ended were taken from the OCI-prepared unaudited financial statements.

Operating results:

	For the Year Ended December 31, 2013 (In thousands)
Net sales	$ 442,132
Gross profit	$ 94,299
Net income	$ 79,655
Income allocation to NRP s equity interests	$ 37,036
Amortization of basis difference	$ (2,850)
Equity and other unconsolidated investment income	$ 34,186

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Balance Sheet information:

	December 31, 2013 (In thousands) (Unaudited)
Current assets	$ 201,265
Property, plant and equipment	$ 193,277
Other assets	$ 1,231
Total assets	$ 395,773
Current liabilities	$ 39,663
Long term debt	$ 155,000
Other liabilities	$ 3,779
Members equity	$ 197,331
Total liabilities and capital	$ 395,773
Net book value of NRP s equity interests	$ 96,692
Equity and other unconsolidated investments	$ 269,338
Excess of NRP s investment over net book value of NRP s equity interests	$ 172,646

5. Allowance for Doubtful Accounts

Activity in the allowance for doubtful accounts for the years ended December 31, 2013, 2012 and 2011 was as follows:

	2013	2012 (In thousands)	2011
Balance, January 1	$ 711	$ 393	$ 681
Provision charged to operations:			
Additions to the reserve	278	318	71
Collections of previously reserved accounts			(359)
Total charged (credited) to operations	278	318	(288)
Non-recoverable balances written off	(714)		
Balance, December 31	$ 275	$ 711	$ 393

6. Asset Impairments

For the year ended December 31, 2013, the Partnership recorded asset impairments of $0.7 million on two aggregate properties on BRP LLC. There were no other impairments recorded during 2013.

Gatling West Virginia. In October 2011, the Partnership was informed by Gatling, LLC, a Cline affiliate, that it was idling the operations and was no longer projecting production from the West Virginia mine. The Partnership and Gatling amended the lease with respect to this property to provide that the existing minimum royalty balance of $24.1 million was non-recoupable, that Gatling pay $3.4 million in non-recoupable minimum royalties when they became due in January and April of 2012, that the minimums would be reduced after the first quarter of 2012, and that Gatling would continue to maintain and ventilate the mine. Following the amendment, Gatling satisfied all terms of the lease. Considering all information available at the time of amendment, the Partnership determined that its investment in the Gatling West Virginia property was not fully recoverable by future cash flows. The assets at the time of amendment included coal reserves, certain above market intangibles and coal transportation equipment.

The 2011 asset impairment of $118.4 million was offset by $24.1 million of recoupable minimum payments received from Gatling, LLC to date and $3.4 million in cash payments received in 2012, resulting in a net asset

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impairment of $90.9 million, which is included in operating expenses on the Consolidated Statements of Comprehensive Income.

In December 2012, the Partnership was informed by Gatling that it was dismantling their preparation plant and removing it from the site and cancelling the lease effective June 2013. The Partnership considered this new information as another impairment triggering event and reassessed the remaining coal reserves and coal transportation equipment fair values for impairment. The fair values of both the remaining reserves and transportation equipment were determined using Level 2 market approaches based upon recent comparable transactions. The reserves were adjusted for the mine s specific characteristics. The 2012 asset impairment of $2.6 million is included in operating expenses on the Consolidated Statements of Comprehensive Income. There were no further indicators of impairment since December 2012 on this property.

The net book value and calculated fair values of the assets relating to the Gatling West Virginia operation were as follows**:**

	2012 Measurement Date		2011 Measurement Date	
	Fair Value	Net Book Value	Fair Value	Net Book Value
	(In thousands)			
Coal and other mineral rights, net	$ 4,050	$ 6,618	$ 6,618	$ 76,003
Intangible assets, net				43,855
Plant and equipment, net	1,981	1,981	2,600	7,775
Total	$ 6,031	$ 8,599	$ 9,218	$ 127,633

Gatling Ohio. In December 2011, the Partnership was informed by Gatling Ohio, LLC, a Cline affiliate, that it was idling its operations and was no longer projecting production from the Ohio mine. Gatling Ohio s recoupable minimum royalty balance as of December 31, 2011 was $9.6 million. Considering all information the Partnership determined that its investment in the Gatling Ohio property would not be fully recovered by future cash flows. The assets include coal reserves, certain above market intangibles and coal transportation equipment. The asset impairment of $70.4 million is included in operating expenses in 2011 on the Consolidated Statements of Income. There were no further indicators of impairment since December 2012 on this property.

The net book value as of the measurement date and calculated fair values of the assets relating to the Gatling Ohio operation are as follows:

	2011 Measurement Date	
	Fair Value	Net Book Value
	(In thousands)	
Coal and other mineral rights, net	$ 20,035	$ 56,769
Intangible assets, net		33,670
Plant and equipment, net	2,947	2,947
Total	$ 22,982	$ 93,386

In determining the 2011 impairments of the Gatling West Virginia and Gatling Ohio assets, the fair values of the coal rights were estimated using a weighted combination of Level 3 expected cash flow and Level 2 market approaches. The fair values of the transportation equipment were estimated using Level 2 market approaches. The expected cash flows were developed using estimated annual sales tons, as well as forecasted sales prices and anticipated market royalty rates. The market approaches include references to recent comparable transactions that were adjusted for each mine s specific characteristics. Since Gatling, LLC is no longer projecting production in the near term future for the West Virginia and Ohio properties, the related royalty and transportation contract intangible assets were estimated to have no fair value as of the measurement date.

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7. Plant and Equipment

The Partnership s plant and equipment consist of the following:

	December 31, 2013	December 31, 2012
	(In thousands)	
Plant and equipment at cost	$ 55,271	$ 55,271
Less accumulated depreciation	(28,836)	(22,870)
Net book value	$ 26,435	$ 32,401

	For the years ended December 31,		
	2013	2012	2011
	(In thousands)		
Total depreciation expense on plant and equipment	$ 5,966	$ 6,825	$ 8,589

During the third quarter of 2012, the Partnership sold a preparation plant to Taggart Global USA, LLC, a related party, for $12.3 million. The Partnership received $10.5 million in cash and a note receivable from Taggart, payable over three years for the balance. The Partnership recorded a gain of $4.7 million in 2012 and it is included in Other revenues of the Consolidated Statements of Comprehensive Income. The note receivable balance at December 31, 2012 was $1.7 million and was paid in full during 2013.

8. Mineral Rights

The Partnership s mineral rights consist of the following:

	December 31, 2013	December 31, 2012
	(In thousands)	
Mineral rights	$ 1,894,920	$ 1,815,423
Less accumulated depletion and amortization	(489,465)	(434,950)
Net book value	$ 1,405,455	$ 1,380,473

	For the years ended December 31,		
	2013	2012	2011
	(In thousands)		
Total depletion and amortization expense on mineral interests	$ 54,595	$ 47,042	$ 47,230

9. Intangible Assets

Amounts recorded as intangible assets along with the balances and accumulated amortization at December 31, 2013 and 2012 are reflected in the table below:

	December 31, 2013	December 31, 2012
	(In thousands)	
Contract intangibles	$ 89,421	$ 89,421
Less accumulated amortization	(22,471)	(18,655)
Net book value	$ 66,950	$ 70,766

	For the years ended December 31,		
	2013	2012	2011
	(In thousands)		
Total amortization expense on intangible assets	$ 3,816	$ 4,354	$ 9,298

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The estimates of amortization expense for the periods as indicated below are based on current mining plans and are subject to revision as those plans change in future periods.

Estimated amortization expense (In thousands)	
For year ended December 31, 2014	$ 3,126
For year ended December 31, 2015	3,543
For year ended December 31, 2016	3,508
For year ended December 31, 2017	3,508
For year ended December 31, 2018	3,508

10. Long-Term Debt

As used in this Note 10, references to NRP LP refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC or any of Natural Resource Partners L.P. s subsidiaries. References to Opco refer to NRP (Operating) LLC and its subsidiaries. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP LP. NRP Finance Corporation (NRP Finance) is a wholly owned subsidiary of NRP LP and a co-issuer with NRP LP on the 9.125% senior notes.

Long-term debt consists of the following:

	December 31, 2013	December 31, 2012
	(In thousands)	
NRP LP Debt:		
$300 million 9.125% senior notes, with semi-annual interest payments in April and October, maturing October 2018, issued at 99.007%	$ 297,170	$
Opco Debt:		
$300 million floating rate revolving credit facility, due August 2016	20,000	148,000
$200 million floating rate term loan, due January 2016	99,000	
5.55% senior notes, with semi-annual interest payments in June and December, maturing June 2013		35,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018	23,084	27,700
8.38% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2019	128,571	150,000
5.05% senior notes, with semi-annual interest payments in January and July, with annual principal payments in July, maturing in July 2020	53,846	61,538
5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021	1,538	1,731
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	27,000	30,300
4.73% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2023	75,000	75,000

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	December 31, 2013	December 31, 2012
	(In thousands)	
5.82% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2024	165,000	180,000
8.92% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2014, maturing in March 2024	50,000	50,000
5.03% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2026	175,000	175,000
5.18% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2026	50,000	50,000
NRP Oil and Gas Debt:		
Reserve-based revolving credit facility due 2018		
Total debt	1,165,209	984,269
Less current portion of long term debt	(80,983)	(87,230)
Long-term debt	$ 1,084,226	$ 897,039

NRP LP Debt

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

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

Opco Debt

Senior Notes. Opco made principal payments of $87.0 million on its senior notes during the year ended December 31, 2013. The Opco senior note purchase agreement contains covenants requiring Opco to:

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

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

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

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

Revolving Credit Facility. The weighted average interest rates for the debt outstanding under Opco s revolving credit facility for the twelve months ended December 31, 2013 and year ended December 31, 2012 were 2.23% and 2.09%, respectively. Opco incurs a commitment fee on the undrawn portion of the revolving credit facility at rates ranging from 0.18% to 0.40% per annum. The facility includes an accordion feature whereby Opco may request its lenders to increase their aggregate commitment to a maximum of $500 million on the same terms.

Opco s revolving credit facility contains covenants requiring Opco to maintain:

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

Term Loan Facility. During the first quarter of 2013, Opco also issued $200 million in term debt. The weighted average interest rate for the debt outstanding under the term loan for the twelve months ended December 31, 2013 was 2.43%. Opco repaid $101 million in principal under the term loan during the third quarter of 2013. Repayment terms call for the remaining outstanding balance of $99 million to be paid on January 23, 2016. The debt is unsecured but guaranteed by the subsidiaries of Opco.

Opco s term loan contains covenants requiring Opco to maintain:

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

NRP Oil and Gas Debt

Revolving Credit Facility. In August 2013, NRP Oil and Gas entered into a 5-year, $100 million senior secured, reserve-based revolving credit facility in order to fund capital expenditure requirements related to the development of the non-operated working interests in oil and gas assets located in the Bakken/Three Forks play acquired on August 9, 2013. The credit facility has a borrowing base of $16.0 million as of December 31, 2013 and is secured by a first priority lien and security interest in substantially all of the assets of NRP Oil and Gas. At December 31, 2013, there were no borrowings outstanding under the credit facility.

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

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

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

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

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

a minimum current ratio of 1.0 to 1.0.

Consolidated Principal Payments

The consolidated principal payments due are set forth below:

	NRP LP Senior Notes	Senior Notes	OPCO Credit Facility	Term Loan	NRP Oil & Gas Credit Facility	Total
			(In thousands)			
2014	$	$ 80,983	$	$	$	$ 80,983
2015		80,983				80,983
2016		80,983	20,000	99,000		199,983
2017		80,983				80,983
2018	300,000(1)	80,983				380,983
Thereafter		344,124				344,124
	$ 300,000	$ 749,039	$ 20,000	$ 99,000	$	$ 1,168,039

(1) The 9.125% senior notes due 2018 were issued at a discount and as of December 31, 2013 were carried at $297.2 million.

NRP LP, Opco and NRP Oil and Gas were in compliance with all terms under their long-term debt as of December 31, 2013.

11. Fair Value Measurements

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

	Fair Value As Of		Carrying Value As Of	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
		(In thousands)		
Assets				
Sugar Camp override, current and long-term	$ 6,852	$ 8,817	$ 6,063	$ 7,495
Taggart plant receivable, current and long term	$	$ 1,668	$	$ 1,667
Liabilities				
Long-term debt, current and long-term	$ 1,071,880	$ 876,574	$ 1,046,209	$ 836,269

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

12. Related Party Transactions

Reimbursements to Affiliates of our General Partner

The Partnership s general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with the partnership agreement, the general partner and its affiliates are reimbursed for expenses incurred on the Partnership s behalf. All direct general and administrative expenses are charged to the Partnership as incurred. The Partnership also reimburses indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by our general partner and its affiliates.

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

	For the Years Ended December 31,		
	2013	2012	2011
		(In thousands)	
Reimbursement for services	$ 11,480	$ 9,791	$ 9,136

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

Transactions with Cline Affiliates

Various companies controlled by Chris Cline, including Foresight Energy, lease coal reserves from the Partnership, and the Partnership provides coal transportation services to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest (unaudited) in the Partnership s general partner, as well as 4,917,548 common units (unaudited) at December 31, 2013. At December 31, 2013, the Partnership had accounts receivable totaling $7.7 million from Cline affiliates. In addition, the overriding royalty and the lease of the loadout facility at the Sugar Camp mine are classified as contracts receivable of $51.7 million on the Partnership s Consolidated Balance Sheets. Revenues from the Cline affiliates are as follows:

	For The Years Ended December 31,		
	2013	2012	2011
		(In thousands)	
Coal royalty revenues	$ 54,322	$ 48,567	$ 42,474
Processing fees	1,281	2,409	2,975
Transportation fees	17,977	19,514	16,689
Minimums recognized as revenue	3,477	17,785	
Override revenue	3,226	4,066	2,691
Other revenue	8,149		2,990
	$ 88,432	$ 92,341	$ 67,819

As of December 31, 2013, the Partnership had received $71.4 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $20.0 million was received in the current year.

The Partnership recognized an asset impairment of $90.9 million during the third quarter of 2011 related to certain of the Partnership s assets at the Gatling WV location and $70.4 million during the fourth quarter of 2011 related to certain assets at the Gatling Ohio location. During the fourth quarter of 2012, the Partnership recognized an additional asset impairment of $2.6 million related to the assets at the Gatling WV location due to receiving a termination notice in December 2012 that the lease was cancelled as of June 2013.

During 2013 and 2011, the Partnership recognized gains of $8.1 million and $3.0 million on a reserve swap in Illinois with Williamson Energy. The gains are reflected in the table above in the Other revenue line. The fair value of the reserves was estimated using Level 3 cash flow approach. The expected cash flows were developed using estimated annual sales tons, forecasted sales prices and anticipated market royalty rates. The tons received during 2013 were fully mined during 2013 and the tons received during 2011 were fully mined during 2012, while the tons exchanged are not included in the current mine plans. The gains are located in Other revenues on the Consolidated Statements of Comprehensive Income.

Quintana Capital Group GP, Ltd.

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

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

For the years ended December 31, 2013, 2012 and 2011, the revenues from Taggart were as follows:

	For the Years Ended December 31, 2013	2012 (In thousands)	2011
Processing revenue	$ 1,761	$ 5,580	$ 9,755

During the third quarter of 2012, the Partnership sold a preparation plant back to Taggart Global for $12.3 million. The Partnership received $10.5 million in cash and a note receivable from Taggart, payable over three years for the balance. The Partnership recorded a gain of $4.7 million included in Other income of the Consolidated Statements of Income for the third quarter of 2012. The net book value of the asset sold was $7.6 million. During 2013, when Taggart was sold to Forge the note receivable that we held was paid in full.

At December 31, 2013, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp., a coal mining company traded on the TSX Venture Exchange that is one of the Partnership s lessees in Tennessee. Corbin J. Robertson III, one of the Partnership s directors, is Chairman of the Board of Corsa. Revenues from Corsa are as follows:

	For the Years Ended December 31, 2013	2012 (In thousands)	2011
Coal royalty revenues	$ 4,594	$ 3,486	$ 1,629

At December 31, 2013, the Partnership also had accounts receivable totaling $0.3 million from Corsa.

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13. Commitments and Contingencies

Legal

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

Environmental Compliance

The operations our lessees conduct on the Partnership s properties, as well as the aggregates/industrial minerals and oil and gas operations in which the Partnership has interests, are subject to federal and state environmental laws and regulations. As an owner of surface interests in some properties, the Partnership may be liable for certain environmental conditions occurring on the surface properties. The terms of substantially all of the Partnership s coal, aggregates and industrial mineral leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. Because the Partnership has no employees, employees of Western Pocahontas Properties Limited Partnership make regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. The Partnership believes that our lessees will be able to comply with existing regulations and do not expect any lessee s failure to comply with environmental laws and regulations to have a material impact on our financial condition or results of operations. The Partnership has neither incurred, nor is aware of, any material environmental charges imposed on the Partnership related to our properties for the period ended December 31, 2013. The Partnership is not associated with any environmental contamination that may require remediation costs. However, the Partnership s lessees do conduct reclamation work on the properties under lease to them. Because the Partnership is not the permittee of the mines being reclaimed, the Partnership is not responsible for the costs associated with these reclamation operations. In addition, West Virginia has established a fund to satisfy any shortfall in reclamation obligations. As an owner of working interests in oil and natural gas operations, the Partnership is responsible for its proportionate share of any losses and liabilities, including environmental liabilities, arising from uninsured and underinsured events.

The electric utility industry, which is the most significant end-user of domestic coal, is subject to extensive regulation regarding the environmental impact of its power generation activities. On January 8, 2014, EPA published proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. President Obama has directed EPA to issue proposed regulations on existing fossil fuel-fired power plants in June 2014. The Partnership expects that EPA s proposed regulations for both new and existing power plants will negatively affect the viability of coal-fired power generation, which will ultimately reduce coal consumption and the production of coal from the Partnership s properties.

14. Major Lessees

The Partnership has the following lessees that generated in excess of ten percent of total revenues in any one of the years ended December 31, 2013, 2012, and 2011. Revenues from these lessees are as follows:

	For the Years Ended December 31,					
	2013		2012		2011	
	Revenues	Percent	Revenues	Percent	Revenues	Percent
	(Dollars in thousands)					
Foresight Energy and affiliates	$ 88,432	24.7%	$ 92,341	24.4%	$ 67,819	18.0%
Alpha Natural Resources	$ 55,147	15.4%	$ 81,077	21.4%	$ 107,267	28.4%

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In 2013, the Partnership derived 40.1% of its revenue from two companies listed above. As a result, the Partnership has a significant concentration of revenues with those lessees, although in most cases, with the exception of the Williamson mine operated by an affiliate of Foresight Energy, the exposure is spread over a number of different mining operations and leases. Foresight s Williamson mine alone was responsible for approximately 13.0%, 12.4% and 11.7% of our total revenues for 2013, 2012 and 2011, respectively.

Substantially all of the Partnership s accounts receivable result from amounts due from third-party companies in the coal industry, with approximately 41% of our total revenues being attributable to coal royalty revenues from Appalachia. This concentration of customers may impact the Partnership s overall credit risk, either positively or negatively, in that these entities may be collectively affected by the same changes in economic or other conditions. Receivables are generally not collateralized.

15. Incentive Plans

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

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

A summary of activity in the outstanding grants for the year ended December 31, 2013 are as follows:

Outstanding grants at the beginning of the period	912,314
Grants during the period	369,947
Grants vested and paid during the period	(246,372)
Forfeitures during the period	(22,905)
Outstanding grants at the end of the period	1,012,984

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 common units and because of changes in estimated fair value determined each quarter using the Black-Scholes option valuation model. Risk free interest rates and historical volatility are reset at each calculation based on current rates corresponding to the remaining vesting term for each outstanding grant and ranged from 0.18% to 0.80% and 24.33% to 31.94%, respectively at December 31, 2013. The Partnership s cumulative average dividend rate of 7.32% was used in the calculation at December 31, 2013. The Partnership accrued expenses related to its plans to be reimbursed to its general partner of $9.6 million, $2.9 million and $7.4 million for the years ended December 31, 2013, 2012 and 2011, respectively. In connection with the Long-Term Incentive Plans, cash payments of $7.0 million, $6.6 million and $5.7 million were paid during each of the years ended December 31, 2013, 2012, and 2011, respectively. The grant date fair value was $25.27, $33.38 and $42.93 per unit for awards in 2013, 2012 and 2011, respectively.

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

The unaccrued cost, associated with unvested outstanding grants and related DERs at December 31, 2013, was $9.3 million.

16. Subsequent Events (Unaudited)

The following represents material events that have occurred subsequent to December 31, 2013 through the time of the Partnership s filing its Form 10-K with the SEC:

Distributions

On January 9, 2014, the Partnership declared a distribution of $0.35 per unit to be paid on January 31, 2014 to unitholders of record on January 21, 2014.

Dividends and Distributions Received From Unconsolidated Equity and Other Investments

Subsequent to December 31, 2013, the Partnership received $11.6 million in cash distributions from its investments in OCI.

17. Supplemental Financial Data (Unaudited)

Shown below are selected unaudited quarterly data.

Selected Quarterly Financial Information

(In thousands, except per unit data)

2013	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues and other income	$ 94,332	$ 86,804	$ 82,237	$ 94,744
Depreciation, depletion and amortization	$ 14,762	$ 17,411	$ 17,852	$ 14,352
Income from operations	$ 62,528	$ 55,332	$ 51,624	$ 66,752
Net income	$ 47,906	$ 41,065	$ 36,126	$ 46,981
Net income per limited partner unit	$ 0.43	$ 0.37	$ 0.32	$ 0.42
Weighted average number of common units outstanding	108,887	109,812	109,812	109,812

2012	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues and other income	$ 91,872	$ 90,664	$ 94,175	$ 102,436
Depreciation, depletion and amortization	$ 12,409	$ 15,172	$ 14,485	$ 16,155
Income from operations	$ 64,824	$ 63,492	$ 65,643	$ 73,206
Net income	$ 51,309	$ 49,938	$ 52,001	$ 60,107
Net income per limited partner unit	$ 0.47	$ 0.46	$ 0.48	$ 0.56
Weighted average number of common units outstanding	106,028	106,028	106,028	106,028

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Item 9. ***Changes In and Disagreements with Accountants on Accounting and Financial Disclosure***
None.

Item 9A. ***Controls and Procedures***
Evaluation of Disclosure Controls and Procedures

We carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2013. This evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures are effective in producing the timely recording, processing, summary and reporting of information and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosures.

Management s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2013 based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission 1992 Framework (COSO). Based on that evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2013. No changes were made to our internal control over financial reporting during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Ernst & Young, LLP, the independent registered public accounting firm who audited the Partnership s consolidated financial statements included in this Form 10-K, has issued a report on the Partnership s internal control over financial reporting, which is included herein.

Report of Independent Registered Public Accounting Firm

The Partners of Natural Resource Partners L.P.

We have audited Natural Resource Partners L.P. s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission 1992 framework (the COSO criteria). Natural Resource Partners L.P. s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting . Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Natural Resource Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2013 and 2012, and the related consolidated statements of comprehensive income, partners capital and cash flows for each of the three years in the period ended December 31, 2013 of Natural Resource Partners L.P. and our report dated February 28, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 28, 2014

Item 9B. ***Other Information***
None.

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PART III

Item 10. ***Directors and Executive Officers of the Managing General Partner and Corporate Governance***

As a master limited partnership we do not employ any of the people responsible for the management of our properties. Instead, we reimburse affiliates of our managing general partner, GP Natural Resource Partners LLC, for their services. The following table sets forth information concerning the directors and officers of GP Natural Resource Partners LLC as of the date of this report. Each officer and director is elected for their respective office or directorship on an annual basis. Unless otherwise noted below, the individuals served as officers or directors of the partnership since the initial public offering. Subject to the Investor Rights Agreement with Adena Minerals, LLC, Mr. Robertson is entitled to nominate ten directors, five of whom must be independent directors, to the Board of Directors of GP Natural Resource Partners LLC. Mr. Robertson has delegated the right to nominate two of the directors, one of whom must be independent, to Adena Minerals.

Name	Age	Position with the General Partner
Corbin J. Robertson, Jr.	66	Chairman of the Board and Chief Executive Officer
Nick Carter	67	President and Chief Operating Officer
Dwight L. Dunlap	60	Chief Financial Officer and Treasurer
Wyatt L. Hogan	42	Executive Vice President
Kevin F. Wall	57	Executive Vice President, Operations
Dennis F. Coker	46	Vice President, Aggregates
Kevin J. Craig	45	Vice President, Business Development
David M. Hartz	40	Vice President, Oil and Gas
Kathy H. Roberts	62	Vice President, Investor Relations
Kathryn S. Wilson	39	Vice President, General Counsel and Secretary
Gregory F. Wooten	57	Vice President, Chief Engineer
Kenneth Hudson	59	Controller
Robert T. Blakely	72	Director
Russell D. Gordy	63	Director
Donald R. Holcomb	57	Director
Robert B. Karn III	72	Director
S. Reed Morian	68	Director
Richard A. Navarre	53	Director
Corbin J. Robertson, III	43	Director
Stephen P. Smith	52	Director
Leo A. Vecellio, Jr.	67	Director

Corbin J. Robertson, Jr. has served as Chief Executive Officer and Chairman of the Board of Directors of GP Natural Resource Partners LLC since 2002. Mr. Robertson has vast business experience having founded and served as a director and as an officer of multiple companies, both private and public, and has served on the boards of numerous non-profit organizations. He has served as the Chief Executive Officer and Chairman of the Board of the general partners of Western Pocahontas Properties Limited Partnership since 1986, Great Northern Properties Limited Partnership since 1992, Quintana Minerals Corporation since 1978, and as Chairman of the Board of Directors of New Gauley Coal Corporation since 1986. He also serves as a Principal with Quintana Capital Group, Chairman of the Board of the Cullen Trust for Higher Education and on the boards of the American Petroleum Institute, the National Petroleum Council, the Baylor College of Medicine and the World Health and Golf Association. In 2006, Mr. Robertson was inducted into the Texas Business Hall of Fame.

Nick Carter has served as President and Chief Operating Officer of GP Natural Resource Partners LLC since 2002. He has also served as President of the general partner of Western Pocahontas Properties Limited

Partnership and New Gauley Coal Corporation since 1990 and as President of the general partner of Great Northern Properties Limited Partnership from 1992 to 1998. Prior to 1990, Mr. Carter held various positions with MAPCO Coal Corporation and was engaged in the private practice of law. He is Chairman of the National Council of Coal Lessors, a past Chair of the West Virginia Chamber of Commerce and a board member of the Kentucky Coal Association, West Virginia Coal Association, Indiana Coal Council, National Mining Association, ACCCE, Foundation for the Tri-State Community, Inc., Community Trust Bancorp, Inc. and Vigo Coal Company, Inc.

Dwight L. Dunlap has served as the Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC since 2002. Mr. Dunlap has served as Vice President and Treasurer of Quintana Minerals Corporation since 1987 and as Chief Financial Officer, Treasurer and Assistant Secretary of the general partner of Western Pocahontas Properties Limited Partnership, Chief Financial Officer and Treasurer of Great Northern Properties Limited Partnership and Chief Financial Officer, Treasurer and Secretary of New Gauley Coal Corporation since 2000. Mr. Dunlap has worked for Quintana Minerals Corporation since 1982. Mr. Dunlap is a Certified Public Accountant with over 30 years of experience in financial management, accounting and reporting including six years of audit experience with an international public accounting firm.

Wyatt L. Hogan has served as Executive Vice President of GP Natural Resource Partners since December 2013. Mr. Hogan was Vice President, General Counsel and Secretary of GP Natural Resource Partners LLC from May 2003 to December 2013. Mr. Hogan joined NRP in 2003 from Vinson & Elkins L.L.P., where he practiced corporate and securities law from August 2000 through April 2003. Mr. Hogan also serves as Executive Vice President of Quintana Minerals Corporation, New Gauley Coal Corporation, the general partner of Western Pocahontas Properties Limited Partnership and the general partner of Great Northern Properties Limited Partnership, and from 2003 to October 2013, Mr. Hogan served as General Counsel and Secretary of those entities. He is also a member of the Board of Directors of Quintana Minerals Corporation and represents NRP as one of its appointees to the Partnership Committee of OCI Wyoming L.P. Prior to joining Vinson & Elkins in August 2000, Mr. Hogan practiced corporate and securities law at Andrews & Kurth L.L.P. from September 1997 through July 2000.

Kevin F. Wall has served as Executive Vice President, Operations of GP Natural Resource Partners LLC since December 2008. Mr. Wall served as Vice President Engineering for GP Natural Resource Partners LLC from 2002 to 2008. Mr. Wall has also served as Vice President Engineering of the general partner of Western Pocahontas Properties Limited Partnership since 1998, of the general partner of Great Northern Properties Limited Partnership since 1992, and of New Gauley Coal Corporation since 1998. Mr. Wall also represents NRP as one of its appointees to the Partnership Committee of OCI Wyoming L.P. He has performed duties in the land management, planning, project evaluation, acquisition and engineering areas since 1981. He is a Registered Professional Engineer in West Virginia and is a member of the American Institute of Mining, Metallurgical, and Petroleum Engineers and of the National Society of Professional Engineers. Mr. Wall also serves on the Executive Committee for the National Council of Coal Lessors, the Board of Directors of Leadership Tri-State and the Board of the Virginia Center for Coal and Energy Research and is a past president of the West Virginia Society of Professional Engineers.

Dennis F. Coker is Vice President, Aggregates of GP Natural Resource Partners LLC. Mr. Coker joined NRP in March 2008 from Hanson Building Materials America, where he had been employed since 2002, and most recently served as Director, Corporate Development. Mr. Coker has 19 years of experience in the mining and materials industry, with the last 14 years focused on corporate development activity. Mr. Coker also represents NRP as one of its appointees to the Partnership Committee for OCI Wyoming L.P. Mr. Coker also serves on the Executive Board as Treasurer of the National Stone Sand and Gravel Association.

Kevin J. Craig is the Vice President of Business Development for GP Natural Resource Partners LLC. Mr. Craig joined NRP in 2005 from CSX Transportation, where he served as Terminal Manager for the West Virginia Coalfields. He has extensive marketing and finance experience with CSX since 1996. Mr. Craig also serves as a Delegate to the West Virginia House of Delegates having been elected in 2000 and re-elected in 2002, 2004, 2006, 2008, 2010 and 2012. Mr. Craig currently serves as Chairman of the Committee on Energy. Prior to joining CSX, he served as a Captain in the United States Army.

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David M. Hartz has served as Vice President, Oil and Gas of GP Natural Resource Partners LLC since December 2013. He served as Director, Oil and Gas from 2011 to December 2013. Prior to joining NRP, Mr. Hartz served as Director of Scotia Waterous, the oil and gas investment banking group within Scotia Capital from 2007 until 2011 where he was involved in oil and gas acquisition and divestiture transactions throughout the United States. Prior to investment banking, Mr. Hartz served in a variety of technical positions as a petroleum geologist for Texaco and Hess within several U.S. and international petroleum basins. He is a member of IPAA, Houston Producers Forum, as well as numerous state oil and gas associations.

Kathy H. Roberts is Vice President, Investor Relations of GP Natural Resource Partners LLC. Ms. Roberts joined NRP in July 2002. She was the Principal of IR Consulting Associates from 2001 to July 2002 and from 1980 through 2000 held various financial and investor relations positions with Santa Fe Energy Resources, most recently as Vice President Public Affairs. She is a Certified Public Accountant. Ms. Roberts currently serves on the Board of Directors of the National Association of Publicly Traded Partnerships and has served on the local board of directors of the National Investor Relations Institute and maintained professional affiliations with various energy industry organizations. She has also served on the Executive Committee and as a National Vice President of the Institute of Management Accountants.

Kathryn S. Wilson has served as Vice President, General Counsel and Secretary of GP Natural Resource Partners LLC since December 2013. Ms. Wilson served as Associate General Counsel from March 2013 to December 2013. Since October 2013, Ms. Wilson has also served as General Counsel and Secretary of each of Quintana Minerals Corporation, New Gauley Coal Corporation, the general partner of Western Pocahontas Properties Limited Partnership, and the general partner of Great Northern Properties Limited Partnership. Ms. Wilson practiced corporate and securities law with Vinson & Elkins L.L.P. from September 2001 to February 2010 and from November 2011 to February 2013. Ms. Wilson served as General Counsel of Antero Resources Corporation from March 2010 to June 2011.

Gregory F. Wooten has served as Vice President, Chief Engineer of GP Natural Resource Partners LLC since December 2013. Mr. Wooten joined NRP in 2007, serving as Regional Manager. Prior to joining NRP, Mr. Wooten served as Vice President, COO and Chief Engineer of Dingess Rum Properties, Inc., where he managed coal, oil, gas and timber properties from 1982 until 2007. Prior to 1982, Mr. Wooten worked as a planning and production engineer in the coal industry and is a member of the American Institute of Mining, Metallurgical, and Petroleum Engineers.

Kenneth Hudson has served as the Controller of GP Natural Resource Partners LLC since 2002. He has served as Controller of the general partner of Western Pocahontas Properties Limited Partnership and of New Gauley Coal Corporation since 1988 and of the general partner of Great Northern Properties Limited Partnership since 1992. He was also Controller of Blackhawk Mining Co., Quintana Coal Co. and other related operations from 1985 to 1988. Prior to that time, Mr. Hudson worked in public accounting.

Robert T. Blakely joined the Board of Directors of GP Natural Resource Partners LLC in January 2003. Mr. Blakely has extensive public company experience having served as Executive Vice President and Chief Financial Officer for several companies. From January 2006 until August 2007, he served as Executive Vice President and Chief Financial Officer of Fannie Mae, and from August 2007 to January 2008 as an Executive Vice President at Fannie Mae. From mid-2003 through January 2006, he was Executive Vice President and Chief Financial Officer of MCI, Inc. He previously served as Executive Vice President and Chief Financial Officer of Lyondell Chemical from 1999 through 2002, Executive Vice President and Chief Financial Officer of Tenneco, Inc. from 1981 until 1999 as well as a Managing Director at Morgan Stanley. He served until December 31, 2011 as a Trustee of the Financial Accounting Foundation and is a trustee emeritus of Cornell University. He has served on the Board of Westlake Chemical Corporation since August 2004. In 2009, Mr. Blakely joined the Boards of Directors of Ally Financial (formerly GMAC, Inc.), where he serves as Chairman of the Audit Committee, and Greenhill & Co.

Russell D. Gordy joined the Board of Directors of GP Natural Resource Partners in October 2013. Mr. Gordy brings extensive oil and gas industry, mineral interest and land ownership and financial experience to the Board. Mr. Gordy is currently managing partner and majority owner in SG Interests, a producer of oil and coal bed methane gas, RGGS, which controls mineral acres currently producing oil and gas, coal, iron ore, limestone, and copper, and Rock Creek Ranch. He is also President of Gordy Oil Company, an oil and gas exploration company in the Gulf Coast of Texas and Louisiana, and Gordy Gas Corporation, an oil and gas exploration company in the San Juan Basin of Colorado and New Mexico. Prior to forming SG Interests in 1989, Mr. Gordy was a founding partner of Northwind Exploration Company an exploration company created in 1981 with former Houston Oil and Minerals employees. Mr. Gordy served on the board of directors of Houston Exploration Company from 1987 until 2001.

Donald R. Holcomb joined the Board of Directors of GP Natural Resource Partners LLC in October 2013. Mr. Holcomb brings financial and coal company experience to the Board of Directors. Mr. Holcomb is currently the Chief Executive Officer of Dickinson Fuel Company, Inc., the managing general partner of Dickinson Properties Limited Partnership, a land company in West Virginia. He is also the owner and manager of Ikes Fork, LLC. From 2001 to March 31, 2013, Mr. Holcomb served as Chief Financial Officer for Foresight Reserves LP and its subsidiaries, which companies are affiliated with Christopher Cline. Mr. Holcomb also serves as trustee of various trusts affiliated with the Cline family. Prior to joining Foresight, Mr. Holcomb held a variety of executive management positions, including at Banner Coal & Land Company, Inc., Patriot Automotive Group, Atlantic Mine Supply Company, Inc., and Wind River Consulting, LLC. Mr. Holcomb is a Certified Public Accountant.

Robert B. Karn III joined the Board of Directors of GP Natural Resource Partners LLC in 2002. Mr. Karn brings extensive financial and coal industry experience to the Board of Directors. He currently is a consultant and serves on the Board of Directors of various entities. He was the partner in charge of the coal mining practice worldwide for Arthur Andersen from 1981 until his retirement in 1998. He retired as Managing Partner of the St. Louis office s Financial and Economic Consulting Practice. Mr. Karn is a Certified Public Accountant, Certified Fraud Examiner and has served as president of numerous organizations. He also currently serves on the Board of Directors of Peabody Energy Corporation, Kennedy Capital Management, Inc. and the Board of Trustees of numerous publicly listed closed-end and exchange traded funds of the Guggenheim family of funds.

S. Reed Morian joined the Board of Directors of GP Natural Resource Partners LLC in 2002. Mr. Morian has vast executive business experience having served as Chairman and Chief Executive Officer of several companies since the early 1980s and serving on the board of other companies. Mr. Morian has served as a member of the Board of Directors of the general partner of Western Pocahontas Properties Limited Partnership since 1986, New Gauley Coal Corporation since 1992 and the general partner of Great Northern Properties Limited Partnership since 1992. Mr. Morian worked for Dixie Chemical Company from 1971 to 2006 and served as its Chairman and Chief Executive Officer from 1981 to 2006. He has also served as Chairman, Chief Executive Officer and President of DX Holding Company since 1989. He formerly served on the Board of Directors for the Federal Reserve Bank of Dallas-Houston Branch from April 2003 until December 2008 and as a Director of Prosperity Bancshares, Inc. from March 2005 until April 2009.

Richard A. Navarre joined the Board of Directors of GP Natural Resource Partners LLC in October 2013. Mr. Navarre brings extensive financial, strategic planning, public company and coal industry experience to the Board of Directors. From 1993 until 2012, Mr. Navarre held several executive positions with Peabody Energy Corporation, including President Americas from March 2012 to June 2012, President and Chief Commercial Officer from January 2008 to March 2012, Executive Vice President of Corporate Development and Chief Financial Officer from July 2006 to January 2008 and Chief Financial Officer from October 1999 to June 2008. Since his retirement from Peabody Energy in 2012, Mr. Navarre has provided advisory services to the coal industry and private equity firms. Mr. Navarre serves as Chairman of the Board of United Coal Company, LLC and as an Advisory Board member for Secure Energy, LLC. He is a member of the Hall of Fame of the College of Business, a member of the Board of Advisors of the College of Business and Administration and an emeritus member of the School of Accountancy of Southern Illinois University Carbondale. He is a member of the Board of Directors of the Foreign Policy Association and is the former Chairman of the Bituminous Coal Operators Association and former advisor to the New York Mercantile Exchange. Mr. Navarre also has been involved in numerous charitable organizations throughout his career.

Corbin J. Robertson, III joined the Board of Directors of GP Natural Resource Partners LLC in May 2013. Mr. Robertson has experience with investments in a variety of energy businesses, having served both in

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management of private equity firms and having served on several boards of directors. Mr. Robertson has served as a Co-Managing Partner of LKCM Headwater Investments GP, LLC and LKCM Headwater Investments I, L.P., a private equity fund, since June 2011. He has served as the Chief Executive Officer of the general partner of Western Pocahontas Properties Limited Partnership since May 2008, and has served on the Board of Directors of Western Pocahontas since October 2012. Mr. Robertson also co-founded Quintana Energy Partners, an energy-focused private equity firm in 2006, and served as a Managing Director thereof from 2006 until December 2010. Mr. Robertson has served on the Board of Directors for Quintana Minerals Corporation since October 2007, and previously served as Vice President Acquisitions for GP Natural Resource Partners LLC from 2003 until 2005. Mr. Robertson also serves on the Board of Directors of the general partner of Genesis Energy L.P., a publicly traded master limited partnership, as well as Corsa Coal Corp, Buckhorn Energy Services and LL&B Minerals, each of which is in the energy business. Mr. Robertson is the son of Corbin J. Robertson, Jr.

Stephen P. Smith joined the Board of Directors of GP Natural Resource Partners LLC in 2004. Mr. Smith brings extensive public company financial experience in the power and energy industries to the Board of Directors. Mr. Smith has been the Executive Vice President and Chief Financial Officer for NiSource, Inc. since June 2008. Prior to joining NiSource, he held several positions with American Electric Power Company, Inc, including Senior Vice President Shared Services from January 2008 to June 2008, Senior Vice President and Treasurer from January 2004 to December 2007, and Senior Vice President Finance from April 2003 to December 2003. From November 2000 to January 2003, Mr. Smith served as President and Chief Operating Officer Corporate Services for NiSource Inc. Prior to joining NiSource, Mr. Smith served as Deputy Chief Financial Officer for Columbia Energy Group from November 1999 to November 2000 and Chief Financial Officer for Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company from 1996 to 1999.

Leo A. Vecellio, Jr. joined the Board of Directors of GP Natural Resource Partners LLC in May 2007. Mr. Vecellio brings extensive experience in the aggregates and coal mine development industry to the Board of Directors. Mr. Vecellio and his family have been in the aggregates materials and construction business since the late 1930s. Since November 2002, Mr. Vecellio has served as Chairman and Chief Executive Officer of Vecellio Group, Inc, a major aggregates producer, contractor and oil terminal developer/operator in the Mid-Atlantic and Southeastern states. For nearly 30 years prior to that time Mr. Vecellio served in various capacities with Vecellio & Grogan, Inc., having most recently served as Chairman and Chief Executive Officer from April 1996 to November 2002. Mr. Vecellio is the former Chairman of the American Road and Transportation Builders and is a longtime member of the Florida Council of 100, as well as many other civic and charitable organizations.

Corporate Governance

Board Attendance and Executive Sessions

During 2013, there were several changes to the Board of Directors of GP Natural Resource Partners LLC. In May 2013, W.W. Scott, Jr. retired from the Board, and Corbin J. Robertson, III was appointed to serve on the Board. In October 2013, David M. Carmichael retired from the Board, and J. Matthew Fifield resigned from the Board. Messrs. Gordy, Holcomb and Navarre were appointed to the Board in October 2013.

The Board met ten times in 2013. During that period, every director attended all of the Board meetings, with the exception of Mr. Fifield, who missed two meetings prior to his resignation from the Board in October 2013, and Mr. Scott, who missed one meeting prior to his resignation from the Board in May 2013. During 2013, our non-management directors met in executive session several times. The presiding director of the February meeting was David Carmichael, the Chairman of our Compensation, Nominating and Governance Committee, or CNG Committee, at that time. The presiding director of the December meeting was Robert T. Blakely, the Chairman of the CNG Committee following Mr. Carmichael s retirement from the Board in October 2013. In addition, our independent directors met one time in executive session in May 2013. Mr. Carmichael was the presiding director at this meeting. Interested parties may communicate with our non-management directors by writing a letter to the Chairman of the CNG Committee, NRP Board of Directors, 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

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Independence of Directors

The Board of Directors has affirmatively determined that Messrs. Blakely, Carmichael, Gordy, Karn, Navarre, Smith and Vecellio are independent based on all facts and circumstances considered by the Board, including the standards set forth in Section 303A.02(a) of the NYSE s listing standards. Although we had a majority of independent directors in 2013, because we are a limited partnership as defined in Section 303A of the NYSE s listing standards, we are not required to do so. The Board has an Audit Committee, a Compensation, Nominating and Governance Committee, and a Conflicts Committee, each of which is staffed solely by independent directors.

Audit Committee

Our Audit Committee is comprised of Robert B. Karn III, who serves as chairman, Robert T. Blakely, Richard A. Navarre and Stephen P. Smith. Mr. Carmichael served on the audit committee until his retirement in October 2013, and Mr. Navarre joined the committee in December 2013. Mr. Karn, Mr. Blakely, Mr. Navarre and Mr. Smith are Audit Committee Financial Experts as determined pursuant to Item 407 of Regulation S-K. Mr. Blakely currently serves on four audit committees. In accordance with the rules of the NYSE, our Board of Directors has made the determination that Mr. Blakely s service on four audit committees does not impair his ability to serve effectively on our audit committee.

Report of the Audit Committee

Our Audit Committee is composed entirely of independent directors. The members of the Audit Committee meet the independence and experience requirements of the New York Stock Exchange. The Committee has adopted, and annually reviews, a charter outlining the practices it follows. The charter complies with all current regulatory requirements. The Audit Committee Charter is available on our website at *www.nrplp.com* and is available in print upon request.

During 2013, at each of its meetings, the Committee met with the senior members of our financial management team, our general counsel and our independent auditors. The Committee had private sessions at certain of its meetings with our independent auditors and the senior members of our financial management team at which candid discussions of financial management, accounting and internal control issues took place.

The Committee approved the engagement of Ernst & Young LLP as our independent auditors for the year ended December 31, 2013 and reviewed with our financial managers and the independent auditors overall audit scopes and plans, the results of internal and external audit examinations, evaluations by the auditors of our internal controls and the quality of our financial reporting.

Management has reviewed the audited financial statements in the Annual Report with the Audit Committee, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant accounting judgments and estimates, and the clarity of disclosures in the financial statements. In addressing the quality of management s accounting judgments, members of the Audit Committee asked for management s representations and reviewed certifications prepared by the Chief Executive Officer and Chief Financial Officer that our unaudited quarterly and audited consolidated financial statements fairly present, in all material respects, our financial condition and results of operations, and have expressed to both management and auditors their general preference for conservative policies when a range of accounting options is available.

The Committee also discussed with the independent auditors other matters required to be discussed by the auditors with the Committee by PCAOB Auditing Standard AU Section 380, *Communication With Audit Committees.* The Committee received and discussed with the auditors their annual written report on their independence from the partnership and its management, which is made under Rule 3526, *Communication With Audit Committees Concerning Independence,* and considered with the auditors whether the provision of non-audit services provided by them to the partnership during 2013 was compatible with the auditors independence.

In performing all of these functions, the Audit Committee acts only in an oversight capacity. The Committee reviews our quarterly and annual reporting on Form 10-Q and Form 10-K prior to filing with the Securities and

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Exchange Commission. In 2013, the Committee also reviewed quarterly earnings announcements with management and representatives of the independent auditor in advance of their issuance. In its oversight role, the Committee relies on the work and assurances of our management, which has the primary responsibility for financial statements and reports, and of the independent auditors, who, in their report, express an opinion on the conformity of our annual financial statements with U.S. generally accepted accounting principles.

In reliance on these reviews and discussions, and the report of the independent auditors, the Audit Committee has recommended to the Board of Directors, and the Board has approved, that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2013, for filing with the Securities and Exchange Commission.

Robert B. Karn III, Chairman

Robert T. Blakely

Stephen P. Smith

Richard A. Navarre

Compensation, Nominating and Governance Committee Authority

Executive officer compensation is administered by the CNG Committee, which is comprised of four members. Mr. Blakely, the Chairman, has served on this Committee since 2003. Mr. Karn has served on the Committee since 2002. Mr. Vecellio joined the committee in 2007, and Mr. Gordy joined the Committee in December 2013. Mr. Carmichael served on the Committee until his retirement from the Board in October 2013. The CNG Committee has reviewed and approved the compensation arrangements described in the Compensation Discussion and Analysis section of this Form 10-K. Our Board of Directors appoints the CNG Committee and delegates to the CNG Committee responsibility for:

- reviewing and approving the compensation for our executive officers in light of the time that each executive officer allocates to our business;
- reviewing and recommending the annual and long-term incentive plans in which our executive officers participate; and
- reviewing and approving compensation for the Board of Directors.

Our Board of Directors has determined that each committee member is independent under the listing standards of the NYSE and the rules of the SEC.

Pursuant to its charter, the CNG Committee is authorized to obtain at NRP s expense compensation surveys, reports on the design and implementation of compensation programs for directors and executive officers and other data that the CNG Committee considers as appropriate. In addition, the CNG Committee has the sole authority to retain and terminate any outside counsel or other experts or consultants engaged to assist it in the evaluation of compensation of our directors and executive officers. The CNG Committee Charter is available on our website at *www.nrplp.com* and is available in print upon request.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of their equity securities. These people are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required for transactions occurring in 2013 and except as described below, we believe that our officers and directors and persons who beneficially own more than ten percent of a registered class of our equity securities complied with all filing requirements with respect to transactions in our equity securities during 2013.

On August 12, 2013, J. Matthew Fifield (who served on our Board of Directors from January 2007 to October 2013), filed one Form 4 reporting three purchases of common units that had not been previously reported on a timely basis. These purchases reported by Mr. Fifield were made in 2012 and 2013 pursuant to an automatic distribution reinvestment feature in a brokerage account. In addition, on August 26, 2013, Corbin J. Robertson, Jr. filed a Form 4 that reported his ownership of 2,000 common units that had not been previously reported on a timely basis. Mr. Robertson has held those units since our initial public offering in 2002 (giving effect to the two-for-one unit split in 2007).

Partnership Agreement

Investors may view our partnership agreement and the amendments to the partnership agreement on our website at *www.nrplp.com*. The partnership agreement and the amendments are also filed with the SEC and are available in print to any unitholder that requests them.

Corporate Governance Guidelines and Code of Business Conduct and Ethics

We have adopted Corporate Governance Guidelines. We have also adopted a Code of Business Conduct and Ethics that applies to our management, and complies with Item 406 of Regulation S-K. Our Corporate Governance Guidelines and our Code of Business Conduct and Ethics are available on our website at *www.nrplp.com* and are available in print upon request.

NYSE Certification

Pursuant to Section 303A of the NYSE Listed Company Manual, in 2013, Corbin J. Robertson, Jr. certified to the NYSE that he was not aware of any violation by the Partnership of NYSE corporate governance listing standards.

Item 11. ***Executive Compensation***
Compensation Discussion and Analysis

Overview

As a publicly traded partnership, we have a unique employment and compensation structure that is different from that of a typical public corporation. We have no employees, and our executive officers based in Houston, Texas are employed by Quintana Minerals Corporation and our executive officers based in Huntington, West Virginia are employed by Western Pocahontas Properties Limited Partnership, both of which are our affiliates. For a more detailed description of our structure, see Item 1, Business Partnership Structure and Management in this Form 10-K. Although our executives salaries and bonuses are paid directly by the private companies that employ them, we reimburse those companies based on the time allocated to NRP by each executive officer. Our reimbursement for the compensation of executive officers is governed by our partnership agreement.

Executive Officer Compensation Strategy and Philosophy

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Our primary business objective is to generate cash flows at levels that can sustain long-term quarterly cash distributions to our investors. Our executive officer compensation strategy has been designed to motivate and retain our executive officers and to align their interests with those of our unitholders. Our primary objective in determining the compensation of our executive officers is to encourage them to build the partnership in a way that ensures the stability of the cash distributions to our unitholders and growth in our asset base. We do not tie our compensation to achievement of specific financial targets or fixed performance criteria, but rather evaluate the appropriate compensation on an annual basis in light of our overall business objectives.

In accordance with our objective of sustaining and increasing the quarterly distribution over the long-term, we believe that optimal alignment between our unitholders and our executive officers is best achieved by compensating our executive officers through sharing a percentage of distributions received by our general partner and through DERs tied to long-term equity-based compensation. The DERs are contingent rights, granted in tandem with specific phantom units, to receive an amount in cash equal to the cash distributions made by NRP

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with respect to its units during the period such phantom unit are outstanding. As discussed further below, our decision to reduce the distribution with respect to the fourth quarter of 2013 will result in significantly reduced compensation for our executive officers in 2014. Our compensation for executive officers consists of four primary components:

- base salaries;
- annual cash incentive awards, including bonuses and cash payments made by our general partner based on a percentage of the cash it receives from common units that the general partner owns;
- long-term equity incentive compensation; and
- perquisites and other benefits.

Mr. Robertson does not receive a salary or an annual bonus in his capacity as Chief Executive Officer. Rather, for the reasons discussed in greater detail below, Mr. Robertson is compensated exclusively through long-term phantom unit grants awarded by the CNG Committee and through sharing a percentage of the distributions received by the general partner. Mr. Robertson also directly or indirectly owns in excess of 20% of the outstanding common units of NRP, and thus his interests are directly aligned with our unitholders.

In December of each year, our CNG Committee reviews the performance of the executive officers and the amount of time expected to be spent by each NRP officer on NRP business, and determines the salaries for each officer for the upcoming year. All of our executive officers other than Mr. Robertson spend 95% or more of their time on NRP matters and NRP bears the allocated cost of their time. Mr. Robertson has historically spent approximately 50% of his time on NRP matters.

In February of each year, the CNG Committee approves the year-end bonuses for the year just ended and long-term incentive awards for the executive officers. The CNG Committee considers the performance of the partnership, the performance of the individuals and the outlook for the future in determining the amounts of the awards. Because we are a partnership, tax and accounting conventions make it more costly for us to issue additional common units or options as incentive compensation. Consequently, we have no outstanding options or restricted units and have no plans to issue options or restricted units in the future. Instead, we have issued phantom units to our executive officers that are paid in cash based on the average closing price of our common units for the 20-day trading period prior to vesting. The phantom units typically vest four years from the date of grant. In connection with the phantom unit awards, the CNG Committee has also granted tandem DERs, which entitle the holders to receive distributions equal to the distributions paid on our common units. The DERs have a four-year vesting period. Through these awards, each executive officer s interest is aligned with those of our unitholders in sustaining and increasing our quarterly cash distributions over the long-term, increasing the value of our common units, and maintaining a steady growth profile for NRP.

Role of Compensation Experts

The CNG Committee did not retain any consultants to evaluate compensation of officers or directors in 2013. The CNG Committee periodically has utilized consultants to get a basic sense of the market, but has considered the advice of the consultant as only one factor among the other items discussed in this compensation discussion and analysis. For a more detailed description of the CNG Committee and its responsibilities, see Item 10, Directors and Executive Officers of the Managing General Partner and Corporate Governance.

Role of Our Executive Officers in the Compensation Process

Mr. Robertson and Mr. Carter provided recommendations to the CNG Committee in its evaluation of the 2013 compensation programs for our executive officers. Mr. Carter provided Mr. Robertson with recommendations relating to the executive officers, other than himself, that are based in Huntington. Mr. Robertson considered those recommendations and provided the CNG Committee with recommendations for all of the executive officers, including the Houston-based officers other than himself. Mr. Robertson and Mr. Carter relied on their personal experience in setting compensation over a number of years in determining the

appropriate amounts for each employee, and considered each of the factors described elsewhere in this compensation discussion and analysis. Mr. Robertson and Mr. Carter attended the CNG Committee meetings at which the Committee deliberated and approved the compensation, but were excused from the meetings when the CNG Committee discussed their compensation. No other named executive officer assumed an active role in the evaluation or design of the 2013 executive officer compensation programs.

Evaluation of 2013 Performance; Components of Compensation

2013 Performance

In 2013, we spent approximately $365 million to acquire additional assets that will help secure the future growth of the partnership. These acquisitions consisted of the purchase of the 49% interest in OCI Wyoming s trona mining and soda ash production business and the acquisition of non-operated working interests in oil and gas assets in the Williston Basin of North Dakota and Montana. These efforts are reflective of NRP management s desire to continue to grow and diversify the partnership to ensure the stability of future revenues and distributions to our unitholders.

In terms of financial performance, we recorded revenues in 2013 of $358.1 million, which were 6% lower than our revenues in 2012. In addition, our 2013 earnings of $1.54 per unit were less than the $2.00 per unit in 2012 (after accounting for non-cash impairment charges in 2012). However, our distributable cash flow was up 3.5% compared to 2013, with the cash distributions received from OCI Wyoming offsetting decreased coal royalty revenues. These results were consistent with the guidance that we issued to the public markets in February 2013 as updated in August 2013.

Looking forward, coal royalty revenues are expected to continue to decline during 2014 as a result of lower expected pricing and production volumes. The reduced coal royalty revenues, together with increased interest expense related to NRP s 9$^1/_8$% senior notes issued in September, result in a substantial decrease in projected distributable cash flow for 2014 as compared to distributable cash flow for 2013, as disclosed in the guidance that we issued in January 2014. As a result, our Board of Directors decreased the quarterly distribution to our unitholders with respect to the fourth quarter of 2013. The decreased quarterly distribution has resulted in substantially lower trading prices for our units to date in 2014 as compared to the 2013 trading prices. The quarterly distribution level and unit trading prices are important criteria for our CNG Committee when considering compensation.

Base Salaries

With the exception of Mr. Robertson, who, as described above, does not receive a salary for his services as Chief Executive Officer, our named executive officers are paid an annual base salary by Quintana and Western Pocahontas for services rendered to us by the executive officers during the fiscal year. We then reimburse Quintana and Western Pocahontas based on the time allocated by each executive officer to our business. The base salaries of our named executive officers are reviewed on an annual basis as well as at the time of a promotion or other material change in responsibilities. The CNG Committee reviews and approves the full salaries paid to each executive officer by Quintana and Western Pocahontas, based on both the actual time allocations to NRP in the prior year and the anticipated time allocations in the coming year. Adjustments in base salary are based on an evaluation of individual performance, our partnership s overall performance during the fiscal year and the individual s contribution to our overall performance.

In determining salaries for NRP s executive officers for 2014, at the December 2013 meeting, the CNG Committee considered the financial performance of NRP for the nine months ended September 30, 2013 as well as the projected financial performance of NRP for the fourth quarter of 2013 and for the year ending December 31, 2014. The CNG Committee also considered the individual performance of each member of the executive management team during 2013 and the changes to the management team that became effective on December 17, 2013. Based on its review, the CNG Committee determined to increase 2014 salaries for those members of the management team whose responsibilities at NRP have increased beginning in 2014 by 5% over 2013 salaries and to hold salaries constant for the other members of the management team as compared to 2013.

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Annual Cash Incentive Awards

Each named executive officer, other than Mr. Robertson, participated in two cash incentive programs in 2013. The first program is a discretionary cash bonus award approved in February 2014 by the CNG Committee based on similar criteria used to evaluate the annual base salaries and based on the January 2014 distribution reduction. The bonuses awarded with respect to 2013 under this program are disclosed in the Summary Compensation Table under the Bonus column. As with the base salaries, there are no formulas or specific performance targets related to these awards. For the reasons stated above under 2013 Performance, the CNG Committee reduced 2013 bonuses to the executive officers by 10% as compared to 2012.

Under the second cash incentive program, our general partner has set aside 7.5% of the cash distributions it receives on an annual basis with respect to distributions on common units held by our general partner for awards to our executive officers, including Mr. Robertson. Although Mr. Robertson has the sole discretion to determine the amount of the 7.5% that is allocated to each executive officer, including himself, the cash awards that our officers receive under this plan are reviewed by the CNG Committee and taken into account when making determinations with respect to salaries, bonuses and long-term incentive awards. Because they are ultimately reimbursed by the general partner and not NRP, the incentive payments made with respect to this program do not have any impact on our financial statements or cash available for distribution to our unitholders. Since the cost of these awards is not borne by NRP, we have not disclosed the amounts of these awards in the Summary Compensation Table, but have included the amounts separately in a footnote to the table. The amounts received by the named executive officers, other than Mr. Robertson, were held constant in 2013, as the per unit distribution actually paid by NRP during the calendar year ended December 31, 2013 was held constant relative to 2012. In determining the total compensation package for each executive officer, the CNG Committee considered the likelihood that the cash incentive payments to NRP s executive officers made from a portion of the cash distributions on common units held by our general partner will be lower in future years relative to 2013 to the extent that NRP s quarterly distribution level remains below the $0.55 per quarter level actually paid in 2013. We believe that these awards align the interests of our executive officers directly with our unitholders.

Long-Term Incentive Compensation

At the time of our initial public offering, we adopted the Natural Resource Partners Long-Term Incentive Plan for our directors and all the employees who perform services for NRP, including the executive officers. We consider long-term equity-based incentive compensation to be the most important element of our compensation program for executive officers because we believe that these awards keep our officers focused on the growth of NRP, particularly the sustainability and long-term growth of quarterly distributions and their impact on our unit price, over an extended time horizon.

Consistent with this approach, we have included DERs as a possible award to be granted under the plan. The DERs are contingent rights, granted in tandem with phantom units, to receive an amount in cash equal to the cash distributions made by NRP with respect to the common units during the period in which the phantom units are outstanding.

Our CNG Committee has generally approved annual awards of phantom units that vest four years from the date of grant. The amounts included in the compensation table reflect the grant date fair value of the unit awards determined in accordance with FASB stock compensation authoritative guidance. We have structured the phantom unit awards so that our executive officers and directors directly benefit along with our unitholders when our unit price increases, and experience reductions in the value of their incentive awards when our unit price declines. Similarly, because the awards are forfeited by the executives upon termination of employment in most instances, the long-term vesting component of these awards encourages our senior executives and employees to remain with NRP over an extended period of time, thereby ensuring continuity in our management team. This strategy has proved effective as NRP s senior management team has experienced no turnover since the initial public offering.

In determining 2014 LTIP awards for NRP s executive officers, at the February 2014 meeting, the CNG Committee considered the financial performance of NRP for the year ended December 31, 2013 as well as the projected financial performance of NRP for the year ending December 31, 2014. The CNG Committee also considered the reduction in the distribution with respect to the fourth quarter of 2013 declared in January 2014 and the related decline in NRP s unit price following the declaration of the reduced distribution. The CNG Committee determined to increase 2014 LTIP awards for NRP s executive officers by 5% over 2013 LTIP awards. In approving the 2014 LTIP awards, the CNG Committee also considered the decreased value realized by each executive officer for LTIP awards vesting in 2014 as compared to 2013 as a result of NRP s decreased quarterly distribution level and related lower unit trading price.

Perquisites and Other Personal Benefits

Both Quintana and Western Pocahontas maintain employee benefit plans that provide our executive officers and other employees with the opportunity to enroll in health, dental and life insurance plans. Each of these benefit plans require the employee to pay a portion of the health and dental premiums, with the company paying the remainder. These benefits are offered on the same basis to all employees of Quintana and Western Pocahontas, and the company costs are reimbursed by us to the extent the employee allocates time to our business.

Quintana and Western Pocahontas also maintain 401(k) and defined contribution retirement plans. Quintana matches 100% of the first 4.5% of the employee contributions under the 401(k) plan and Western Pocahontas matches the employee contributions at a level of 100% of the first 3% of the contribution and 50% of the next 3% of the contribution. In addition, each company contributes 1/12 of each employee s base salary to the defined contribution retirement plan on an annual basis. As with the other contributions, any amounts contributed by Quintana and Western Pocahontas are reimbursed by us based on the time allocated by the employee to our business. The payments made to Messrs. Carter, Dunlap, Hogan and Wall under the defined contribution plan exceeded $10,000 in each of 2011, 2012 and 2013, but did not exceed $25,000 for any individual in any year. None of NRP, Quintana or Western Pocahontas maintains a pension plan or a defined benefit retirement plan. As noted in the Summary Compensation Table, in 2011, 2012 and 2013 we also reimbursed Quintana and Western Pocahontas for car allowances provided to Messrs. Carter, Dunlap and Wall.

Unit Ownership Requirements

We do not have any policy guidelines that require specified ownership of our common units by our directors or executive officers or unit retention guidelines applicable to equity-based awards granted to directors or executive officers. As of December 31, 2013, our named executive officers held 302,000 phantom units that have been granted as compensation. In addition, Mr. Robertson directly or indirectly owns in excess of 20% of the outstanding units of NRP.

Securities Trading Policy

Our insider trading policy states that executive officers and directors may not purchase or sell puts or calls to sell or buy our common units, engage in short sales with respect to our common units, or buy our securities on margin.

Tax Implications of Executive Compensation

Because we are a partnership, Section 162(m) of the Internal Revenue Code does not apply to compensation paid to our named executive officers and accordingly, the CNG Committee did not consider its impact in determining compensation levels in 2011, 2012 or 2013. The CNG Committee has taken into account the tax implications to the partnership in its decision to limit the long-term incentive compensation to phantom units as opposed to options or restricted units.

Accounting Implications of Executive Compensation

The CNG Committee has considered the partnership accounting implications, particularly the book-up cost, of issuing equity as incentive compensation, and has determined that phantom units offer the best accounting treatment for the partnership while still motivating and retaining our executive officers.

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Report of the Compensation, Nominating and Governance Committee

The CNG Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management. Based on the reviews and discussions referred to in the foregoing sentence, the CNG Committee recommended to the board of directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the year ended December 31, 2013.

Robert T. Blakely, Chairman

Russell D. Gordy

Robert B. Karn III

Leo A. Vecellio, Jr.

Summary Compensation Table

The following table sets forth the amounts reimbursed to affiliates of our general partner for compensation expense in 2011, 2012 and 2013 based on time allocated by each individual to Natural Resource Partners. In 2013, Messrs. Robertson, Dunlap, Carter, Hogan and Wall spent approximately 50%, 97%, 97%, 96% and 95%, respectively, of their time on NRP matters.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Phantom Unit Awards(1) ($)	All Other Compensation(2) ($)	Total ($)
Corbin J. Robertson, Jr.	2013			712,000		712,000
Chairman and CEO	2012			830,400		830,400
	2011			1,156,980		1,156,980
Dwight L. Dunlap	2013	328,193	126,900	222,500	38,537	716,130
CFO and Treasurer	2012	325,189	141,000	259,500	37,577	763,266
	2011	313,885	156,500	315,540	36,755	822,680
Nick Carter	2013	378,300	199,260	356,000	40,473	974,033
President and Chief Operating Officer	2012	378,300	221,400	415,200	39,851	1,054,751
	2011	368,600	246,000	525,900	39,228	1,179,728
Wyatt L. Hogan	2013	344,970	126,900	222,500	31,358	725,728
Executive Vice President	2012	328,337	141,000	259,500	30,988	759,825
	2011	315,865	156,500	315,540	30,095	818,000
Kevin F. Wall	2013	205,485	126,900	222,500	33,781	588,666
Executive Vice President,	2012	205,485	141,000	259,500	33,781	639,766
Operations	2011	199,500	155,000	315,540	33,013	703,053

(1) Amounts represent the grant date fair value of unit awards determined in accordance with FASB stock compensation authoritative guidance.

(2) Includes portions of automobile allowance, 401(k) matching and retirement contributions allocated to Natural Resource Partners by Quintana Minerals Corporation and Western Pocahontas Properties Limited Partnership. The payments made to Messrs. Carter, Dunlap, Hogan and Wall under the defined contribution plan exceeded $10,000 in each of 2011, 2012 and 2013, but did not exceed $25,000 for any individual in any year. The table does not include any cash compensation paid by the general partner to each named executive officer. The general partner may distribute up to 7.5% of any cash it receives with respect to the common units that it received in connection with the elimination of the incentive distribution rights. We do

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not reimburse the general partner for any of these payments, and the payments are not an expense of NRP. The table below shows the amounts paid by the general partner that are not reimbursed by NRP.

Individual	Year	Compensation Received from General Partner and Not Reimbursed by NRP $
Corbin J. Robertson, Jr.	2013	456,000
	2012	456,000
	2011	530,000
Dwight L. Dunlap	2013	391,000
	2012	391,000
	2011	385,000
Nick Carter	2013	536,000
	2012	536,000
	2011	530,000
Wyatt L. Hogan	2013	391,000
	2012	391,000
	2011	385,000
Kevin F. Wall	2013	391,000
	2012	391,000
	2011	385,000

Grants of Plan-Based Awards in 2013

Named Executive Officer	Grant Date	All Other Unit Awards: Number of Phantom Units(1) (#)	Grant Date Fair Value of Unit Awards(2) ($)
Corbin J. Robertson, Jr.	2/13/2013	32,000	712,000
Dwight L. Dunlap	2/13/2013	10,000	222,500
Nick Carter	2/13/2013	16,000	356,000
Wyatt L. Hogan	2/13/2013	10,000	222,500
Kevin F. Wall	2/13/2013	10,000	222,500

(1) The phantom units were granted in February 2013 and will vest in February 2017.

(2) Amounts represent the estimated fair value on February 13, 2013.

None of our executive officers has an employment agreement, and the salary, bonus and phantom unit awards noted above are approved by the CNG Committee. See our disclosure under Compensation Discussion and Analysis for a description of the factors that the CNG Committee considers in determining the amount of each component of compensation.

Subject to the rules of the exchange upon which the common units are listed at the time, the board of directors and the CNG Committee have the right to alter or amend the Long-Term Incentive Plan or any part of the Long-Term Incentive Plan from time to time. Except upon the occurrence of unusual or nonrecurring events, no change in any outstanding grant may be made that would materially reduce any award to a participant without the consent of the participant.

The CNG Committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of NRP, our general partner or GP Natural Resource Partners LLC. If a grantee s employment or

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membership on the board of directors terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the CNG Committee provides otherwise.

As stated above under Compensation Discussion and Analysis, we have no outstanding option grants, and do not intend to grant any options or restricted unit awards in the future. The CNG Committee regularly makes awards of phantom units on an annual basis in February.

Outstanding Awards at December 31, 2013

The table below shows the total number of outstanding phantom units held by each named executive officer at December 31, 2013. The phantom units shown below have been awarded over the last four years, with a portion of the phantom units vesting in February in each of 2014, 2015, 2016 and 2017.

Named Executive Officer	Number of Phantom Units That Have Not Vested (#)	Market Value of Phantom Units That Have Not Vested(1) ($)
Corbin J. Robertson, Jr.	130,000	3,383,650
Dwight L. Dunlap	37,000	950,340
Nick Carter	61,000	1,682,040
Wyatt L. Hogan	37,000	950,340
Kevin F. Wall	37,000	950,340

(1) Based on a unit price of $19.94, the closing price for the common units on December 31, 2013. The value also includes the value of the accrued DERs as of December 31, 2013.

Phantom Units Vested in 2013

The table below shows the phantom units that vested with respect to each named executive officer in 2013, along with the value realized by each individual.

Named Executive Officer	Number of Phantom Units That Vested (#)	Value Realized on Vesting ($)
Corbin J. Robertson, Jr.	35,000	1,075,200
Dwight L. Dunlap	8,000	245,760
Nick Carter	14,000	430,080
Wyatt L. Hogan	8,000	245,760
Kevin F. Wall	8,000	245,760

Potential Payments upon Termination or Change in Control

None of our executive officers have entered into employment agreements with Natural Resource Partners or its affiliates. Consequently, there are no severance benefits payable to any executive officer upon the termination of their employment. The annual base salaries, bonuses and other compensation are all determined by the CNG Committee in consultation with Mr. Robertson, Mr. Carter and the full board of directors. Upon the occurrence of a change in control of NRP, our general partner or GP Natural Resource Partners LLC, the outstanding phantom unit awards held by each of our executive officers would immediately vest. The table below indicates the impact

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of a change in control on the outstanding equity-based awards at December 31, 2013, based on the 20-day average of the common units of $19.86 on December 31, 2013 and includes amounts for accrued DERs.

Named Executive Officer	Number of Phantom Units That Have Not Vested (#)	Potential Post-Employment Payments Required Upon Change in Control ($)	Potential Cash Payments Required Upon Change in Control ($)
Corbin J. Robertson, Jr.	130,000		3,373,250
Dwight L. Dunlap	37,000		947,380
Nick Carter	61,000		1,677,160
Wyatt L. Hogan	37,000		947,380
Kevin F. Wall	37,000		947,380

Directors Compensation for the Year Ended December 31, 2013

The table below shows the directors compensation for the year ended December 31, 2013. As with our named executive officers, we do not grant any options or restricted units to our directors.

Name	Fees Earned or Paid in Cash ($)	Phantom Unit Awards(2)(3) ($)	Total ($)
Robert Blakely	85,000	102,285	187,285
David Carmichael(1)	70,833	454,903	525,736
J. Matthew Fifield(1)	50,000	102,285	152,285
Russell Gordy(1)	10,000		10,000
Donald Holcomb(1)	10,000		10,000
Robert Karn III	85,000	102,285	187,285
S. Reed Morian	60,000	102,285	162,285
Richard Navarre(1)	10,000		10,000
Corbin J. Robertson, III(1)	30,000		30,000
Stephen Smith	65,000	102,285	167,285
W. W. Scott, Jr.(1)	30,000	496,560	526,560
Leo A. Vecellio, Jr.	65,000	102,285	167,285

(1) Messrs. Carmichael and Fifield served on the Board until October 31, 2013. Mr. Scott served on the Board until May 22, 2013. Corbin J. Robertson, III was appointed to the Board effective May 22, 2013. Messrs. Gordy, Holcomb and Navarre were appointed to the Board effective October 31, 2013.

(2) Amounts represent the grant date fair value of unit awards determined in accordance with FASB stock compensation authoritative guidance. Mr. Fifield forfeited all of his outstanding LTIP units upon his resignation from the Board. Upon Mr. Scott s retirement from the Board, the Board agreed to vest Mr. Scott in his remaining LTIP units. Pursuant to the Board s policy, Mr. Carmichael retired from the Board upon reaching age 75, and vested in his units upon the completion of his final term as a director.

(3)

As of December 31, 2013, except for Messrs. Gordy, Holcomb and Navarre who hold 11,980 phantom units that vest in annual increments of 1,000 units in 2014, 3,580 units in 2015, 3,700 units in 2016 and 3,700 units that vest in 2017, each director held 14,455 phantom units that vest in annual increments of 3,475 units in 2014, 3,580 units in 2015, 3,700 units in 2016 and 3,700 units in 2017.

In 2013, the annual retainer for the directors was $60,000, and the directors did not receive any additional fees for attending meetings. Each chairman of a committee received an annual fee of $10,000 for serving as chairman, and each committee member received $5,000 for serving on a committee.

2014 Long-Term Incentive Awards

In February 2014, the CNG Committee awarded 33,600 phantom units to Mr. Robertson, 16,800 phantom units to Mr. Carter, and 10,500 phantom units to each of Messrs. Dunlap, Hogan and Wall. The phantom units included tandem DERs, pursuant to which the phantom units will accrue the quarterly distributions paid by NRP on its common units. NRP will pay the amounts accrued under the DERs upon the vesting of the phantom units in February 2018. The CNG Committee also approved an award of 3,885 phantom units, including tandem DERs, to each of the members of the Board of Directors. These phantom units will vest in February 2018.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2013, Messrs. Blakely, Karn and Vecellio served on the CNG Committee during the full year. Mr. Carmichael served on the CNG Committee as its Chairman during 2013 until his retirement from the Board on October 31, 2013. Upon Mr. Carmichael s retirement, Mr. Blakely was appointed Chairman of the CNG Committee. Mr. Gordy joined the CNG Committee effective December 17, 2013. None of Messrs. Blakely, Carmichael, Gordy, Karn or Vecellio has ever been an officer or employee of NRP or GP Natural Resource Partners LLC. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has any executive officer serving as a member of our Board of Directors or CNG Committee.

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Item 12. ***Security Ownership of Certain Beneficial Owners and Management***

The following table sets forth, as of February 28, 2014, the amount and percentage of our common units beneficially held by (1) each person known to us to beneficially own 5% or more of any class of our units, (2) by each of the directors and executive officers and (3) by all directors and executive officers as a group. Unless otherwise noted, each of the named persons and members of the group has sole voting and investment power with respect to the units shown.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)
Corbin J. Robertson, Jr.(2)	24,075,925	21.9%
Western Pocahontas Properties(3)	17,279,860	15.7%
Western Bridgeport, Inc.(4)	5,627,120	5.1%
Nick Carter(5)	24,210	*
Dwight L. Dunlap	20,836	*
Wyatt L. Hogan(6)	5,000	*
Kevin F. Wall(7)	4,000	*
Dennis F. Coker	1,500	*
Kevin J. Craig	10,000	*
David M. Hartz	1,140	*
Kenneth Hudson	8,000	*
Kathy H. Roberts	13,000	*
Kathryn S. Wilson		
Gregory F. Wooten		
Robert T. Blakely	22,500	*
Russell D. Gordy	70,000	*
Donald R. Holcomb	120,134	*
Robert B. Karn III (8)	5,634	*
Richard A. Navarre		
S. Reed Morian(9)	6,141,588	5.6%
Corbin J. Robertson III (10)	1,564,698	1.4%
Stephen P. Smith	3,552	*
Leo A. Vecellio, Jr.	20,000	*
Directors and Officers as a Group	32,111,716	29.2%

* Less than one percent.

(1) Percentages based upon 109,812,408 common units issued and outstanding. Unless otherwise noted, beneficial ownership is less than 1%.

(2) Mr. Robertson may be deemed to beneficially own the 17,279,860 common units owned by Western Pocahontas Properties Limited Partnership, 5,627,120 common units held by Western Bridgeport, Inc., 110,206 common units held by Western Pocahontas Corporation and 56 common units held by QMP Inc. Also included are 31,540 common units held by Barbara Robertson, Mr. Robertson s spouse. Mr. Robertson s address is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

(3) These common units may be deemed to be beneficially owned by Mr. Robertson. The address of Western Pocahontas Properties Limited Partnership is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

(4) These common units may be deemed to be beneficially owned by Mr. Robertson. The address of Western Bridgeport is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

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(5) Includes 210 common units held by Mr. Carter s spouse.

(6) Of these common units, 500 common units are owned by the Anna Margaret Hogan 2002 Trust, 500 common units are owned by the Alice Elizabeth Hogan 2002 Trust, and 500 common units are held by the Ellen Catlett Hogan 2005 Trust. Mr. Hogan is a trustee of each of these trusts.

(7) Includes 500 common units held by Mr. Wall s daughter. Mr. Wall disclaims beneficial ownership of these securities.

(8) Includes 317 common units held by the Payton Grace Portnoy Irrevocable Trust and 317 common units held by the Blake Kristopher Portnoy Irrevocable Trust. Mr. Karn is the trustee of each of these trusts for his grandchildren, but disclaims beneficial ownership of these securities.

(9) Mr. Morian may be deemed to beneficially own 3,448,624 common units owned by Shadder Investments and 600,972 common units held by Mocol Properties. The 3,448,624 units owned by Shadder Investments are pledged as collateral for a loan.

(10) Mr. Robertson may be deemed to beneficially own 26,231 common units held CIII Capital Management, LLC, 50,461 common units held by The Corbin James Robertson III 2009 Family Trust and 397 common units held by his spouse, Brooke Robertson. The address for CIII Capital Management, LLC is 601 Jefferson, Suite 3600, Houston, TX 77002 and the address for The Corbin James Robertson III 2009 Family Trust is 601 Jefferson, Suite 3600, Houston, TX 77002. The following common units are pledged as collateral for loans: 1,291,638 common units owned directly by Mr. Robertson and 1,000 of the units held by CIII Capital Management, LLC.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Western Pocahontas Properties Limited Partnership, New Gauley Coal Corporation and Great Northern Properties Limited Partnership are three privately held companies that are primarily engaged in owning and managing mineral properties. We refer to these companies collectively as the WPP Group. Corbin J. Robertson, Jr. owns the general partner of Western Pocahontas Properties, 85% of the general partner of Great Northern Properties and is the Chairman and Chief Executive Officer of New Gauley Coal Corporation.

Omnibus Agreement

Non-competition Provisions

As part of the omnibus agreement entered into concurrently with the closing of our initial public offering, the WPP Group and any entity controlled by Corbin J. Robertson, Jr., which we refer to in this section as the GP affiliates, each agreed that neither they nor their affiliates will, directly or indirectly, engage or invest in entities that engage in the following activities (each, a restricted business) in the specific circumstances described below:

- the entering into or holding of leases with a party other than an affiliate of the GP affiliate for any GP affiliate-owned fee coal reserves within the United States; and

- the entering into or holding of subleases with a party other than an affiliate of the GP affiliate for coal reserves within the United States controlled by a paid-up lease owned by any GP affiliate or its affiliate.

Affiliate means, with respect to any GP affiliate or, any other entity in which such GP affiliate owns, through one or more intermediaries, 50% or more of the then outstanding voting securities or other ownership interests of such entity. Except as described below, the WPP Group and their respective controlled affiliates will not be prohibited from engaging in activities in which they compete directly with us.

A GP affiliate may, directly or indirectly, engage in a restricted business if:

the GP affiliate was engaged in the restricted business at the closing of the offering; provided that if the fair market value of the asset or group of related assets of the restr