NATURAL RESOURCE PARTNERS LP
Form 10-K
February 27, 2015
Table of Contents

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, 2014 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 $1.3 billion on June 30, 2014 based on a price of $16.57 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 27, 2015, there were 122,299,825 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE.

None.

Table of Contents

Table of Contents

Table of Contents

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, oil, natural gas, aggregates and industrial minerals;
- estimated revenues, expenses and results of operations;
- the amount, nature and timing of capital expenditures;
- our ability to make acquisitions and integrate the acquisitions we do make;
- our liquidity and access to capital and financing sources;
- projected production levels by our lessees, VantaCore Partners LLC, and the operators of our oil and gas working interests;
- OCI Wyoming LLC s trona mining and soda ash refinery operations;
- the impact of governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us, and of scheduled or potential regulatory or legal changes; and
- global and U.S. economic conditions.

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

You should not put undue reliance on any forward-looking statements. See Item 1A. Risk Factors in this Annual Report on Form 10-K for important factors that could cause our actual results of operations or our actual financial condition to differ.

Table of Contents

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 a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, crude oil and natural gas, construction aggregates, frac sand and other natural resources. Executing on our plans to diversify our business, we have completed over $900 million in acquisitions since January 2013. For the year ended December 31, 2014, we recorded revenues and other income of $399.8 million and Adjusted EBITDA of $300.3 million. Approximately $226.7 million (57%) of our 2014 revenues and other income were attributable to coal-related sources, and $173.0 million (43%) of our revenues and other income were attributed to non-coal-related sources. Adjusted EBITDA is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA to net income, see Item 6. Selected Financial Data Non-GAAP Financial Measures Adjusted EBITDA.

Our coal reserves are located in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. We do not operate any coal 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, primarily in the Illinois Basin.

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

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

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

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We conduct our business 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 make 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.

We have several regional offices through which we conduct our operations, the largest of which 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.

Coal and Coal-Related Properties

Coal Royalty Business

Royalty businesses principally own and manage mineral reserves. As an owner of coal reserves, we typically are not responsible for operations on our coal 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 to us and are required to report tons of coal removed as well as the sales prices of the extracted coal. 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.

In addition to their royalty obligations, 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. Our current coal royalty leases provide for the payment of approximately $103 million in minimums to us during 2015.

Because we do not operate any coal mines, our coal 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 aggregates properties. We typically pay property taxes on our properties, which are then reimbursed by the lessee pursuant to the terms of the lease.

Table of Contents

Coal Royalty Revenues, Reserves and Production

The following summary table sets forth coal royalty revenues and average coal royalty per ton from the properties that we owned or controlled for the years ending December 31, 2014, 2013 and 2012. Coal royalty revenues were generated from the properties in each of the areas as follows:

	Coal Royalty Revenues Year Ended December 31,			Average Coal Royalty Per Ton Year Ended December 31,		
	2014	2013	2012	2014	2013	2012
	(In thousands)			($ per ton)		
Area						
Appalachia:						
Northern	$ 8,621	$ 14,643	$ 15,768	$ 0.92	$ 1.27	$ 1.50
Central	89,627	105,004	156,390	$ 4.46	$ 5.05	$ 5.99
Southern	20,292	26,156	29,325	$ 5.18	$ 6.30	$ 7.89
Total Appalachia	118,540	145,803	201,483	$ 3.55	$ 4.00	$ 5.00
Illinois Basin	54,049	56,001	49,538	$ 4.10	$ 4.28	$ 4.38
Northern Powder River Basin	7,804	7,569	8,501	$ 2.74	$ 2.72	$ 3.58
Gulf Coast	3,793	3,290	1,212	$ 3.47	$ 3.39	$ 2.60
Total	$ 184,186	$ 212,663	$ 260,734	$ 3.65	$ 3.99	$ 4.79

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, 2014, 2013 and 2012. 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 Year Ended December 31,			Proven and Probable Reserves at December 31, 2014		
	2014	2013	2012	Underground	Surface	Total
	(Tons in thousands)					
Area						
Appalachia:						
Northern	9,339	11,505	10,486	469,206	27,864	497,070
Central	20,092	20,801	26,098	1,017,993	260,598	1,278,591
Southern	3,914	4,151	3,718	83,846	24,730	108,576
Total Appalachia	33,345	36,457	40,302	1,571,045	313,192	1,884,237
Illinois Basin	13,177	13,087	11,299	330,137	15,025	345,162
Northern Powder River Basin	2,844	2,778	2,377		94,157	94,157
Gulf Coast	1,093	970	466		2,696	2,696
Total	50,459	53,292	54,444	1,901,182	425,070	2,326,252

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, 2014, 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 Annual Report on Form 10-K on an as-received basis, which assumes 6% moisture for Appalachian reserves, 12% moisture for Illinois Basin

Table of Contents

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 2014, approximately 32% of the production and 40% of the coal royalty revenues from our properties were from metallurgical coal.

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, 2014.

	Sulfur Content, Typical Quality and Type of Coal								
	Sulfur Content					Typical Quality		Type of Coal	
	Compliance Coal(1)	Low (<1.0%)	Medium (1.0% to 1.5%)	High (>1.5%)	Total	Heat Content (Btu per pound)	Sulfur (%)	Steam	Met(2)
	(Tons in thousands)							(Tons in thousands)	
Area									
Appalachia									
Northern	50,097	72,816	24,466	399,788	497,070	12,831	2.58	487,508	9,562
Central	623,881	885,689	332,186	60,716	1,278,591	13,311	0.90	858,899	419,692
Southern	72,273	78,337	27,499	2,740	108,576	13,509	0.84	78,590	29,986
Total Appalachia	746,251	1,036,842	384,151	463,244	1,884,237	13,196	1.34	1,424,997	459,240
Illinois Basin			2,183	342,979	345,162	11,497	3.28	345,162	
Northern Powder River Basin		94,157			94,157	8,800	0.65	94,157	
Gulf Coast	96	2,696			2,696	6,922	0.69	2,600	96
Total	746,347	1,133,695	386,334	806,223	2,326,252			1,866,916	459,336

(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. See Item 1A. Risk Factors Risks Related to Our Business Our reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of our reserves.

Table of Contents

Major Coal Properties

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

Appalachia

Northern Appalachia

Hibbs Run. The Hibbs Run property is located in Marion County, West Virginia. In 2014, 6.0 million tons were produced from the property by Consolidation Coal Company. 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 2014, 1.4 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 and 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-Ohio. The AFG-Ohio property is located in Belmont County, Ohio. In 2014, 1.4 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 and shipped by rail and barge to customers including AEP, Duke Energy and First Energy.

Table of Contents

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

7

Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2014, 3.8 million tons were produced from this property. We primarily lease this property to a subsidiary of Alpha Natural Resources, Inc. 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, Inc. and Patriot Coal Corporation. In 2014, 2.9 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.

Pinnacle. The Pinnacle property is located in Wyoming and McDowell Counties, West Virginia. In 2014, 2.4 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 and is then shipped via railroad and barge to both domestic and export customers.

Lynch. The Lynch property is located in Harlan and Letcher Counties, Kentucky. In 2014, 2.1 million tons were produced from this property. We primarily lease the property to a subsidiary of Alpha Natural Resources, Inc. Production comes from both underground and surface mines. This property has the ability to ship coal on both the CSX and Norfolk Southern railroads.

VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2014, 1.7 million tons were produced from this property. Coal is produced from a number of lessees, including subsidiaries of TECO and Blackhawk Mining, 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 2014, 1.4 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.

Kingston. The Kingston property is located in Fayette and Raleigh Counties, West Virginia. This property is leased to a subsidiary of Alpha Natural Resources, Inc. In 2014, 1.1 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. During 2014, the lessee idled the surface mines on the property in response to market conditions. 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 Corporation. In 2014, 641,000 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.

Pardee. The Pardee property is located in Letcher County, Kentucky and Wise County, Virginia. In 2014, 512,000 tons were produced from this property. We lease the property to a subsidiary of Arch Coal, Inc. and Revelation Energy. In late 2014, Arch surrendered the surface mineable coal on the lease and we entered into a new lease for those reserves with Revelation Energy. 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.

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

Table of Contents

Southern Appalachia

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2014, 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 2014, 1.5 million tons were produced from these properties. We lease these properties to a number of operators including Middlesboro Mining Properties, Inc., Revelation Energy, LLC 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.

Table of Contents

Illinois Basin

Williamson. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to a subsidiary of Foresight Energy LP, and in 2014, 6.0 million tons were mined on the property. This production is from a longwall mine and 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 a subsidiary of Foresight Energy LP, and in 2014, 5.4 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 a subsidiary of Foresight Energy LP, and in 2014, 1.1 million 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.

Sahara. The Sahara property is located in Saline, Hamilton and Williamson Counties in Illinois. This property was acquired in June of 2014. The property is under lease to a subsidiary of Peabody Energy Corporation, and following the acquisition in 2014, 486,000 tons were mined on the property. Production is currently from an underground mine and is shipped via barge primarily to Tennessee Valley Authority.

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 Foresight Energy LP. See Coal Transportation and Processing Assets.

Table of Contents

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

Table of Contents

Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2014, 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.

Table of Contents

Coal 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.

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. 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.

Total revenues from our coal transportation and processing assets were $22.0 million for the year ended December 31, 2014.

Aggregates and Industrial Minerals Business

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 building construction project and in most public works projects, such as roads, highways, bridges, railroad beds, dams, airports, water and sewage treatment plants and systems and tunnels. Through our subsidiary, VantaCore Partners LLC, we mine and produce construction materials. In addition, we own aggregates reserves throughout the United States, a portion of which are leased to third parties in exchange for royalty payments.

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. We own a 49% noncontrolling equity interest in OCI Wyoming s trona mining and soda ash production operation.

Table of Contents

VantaCore Partners LLC Construction Materials Business

VantaCore is a construction materials company that we acquired on October 1, 2014. VantaCore operates three limestone quarries, five sand and gravel plants, two asphalt plants and a marine terminal. VantaCore is headquartered in Philadelphia, Pennsylvania, and its operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana. As of December 31, 2014, VantaCore controlled approximately 292 million tons of estimated aggregates reserves. The reserve estimates for each of VantaCore s properties were prepared internally and audited by an independent third party advisor. For the three months ended December 31, 2014, VantaCore sold approximately 1.9 million tons of crushed stone and gravel, including brokered stone, 0.4 million tons of sand and 40,000 tons of asphalt. VantaCore s three operating businesses are Laurel Aggregates, located in Lake Lynn, Pennsylvania, Winn Materials/McIntosh Construction, located near Clarksville, Tennessee, and Southern Aggregates, located near Baton Rouge, Louisiana. VantaCore s business is seasonal, with production typically lower in the first quarter of each year due to winter weather. The following map shows the locations of each of VantaCore s operations.

Laurel Aggregates

Laurel Aggregates is a limestone mining company located in Lake Lynn, Pennsylvania. Its operations consist of a surface mine and an underground mine and use conventional drilling, blasting and crushing methods. The surface mine is located on approximately 100 acres of owned property, and the underground reserves are located on approximately 670 acres of leased property. Laurel pays royalties for material mined and sold from its leased property. Laurel also brokers stone for third party quarries located in Ohio and Pennsylvania. Crushed stone is loaded into third party trucks for delivery to customers located in southwestern Pennsylvania, northeastern West Virginia and eastern Ohio. Laurel s customers consist primarily of oilfield service companies and natural gas exploration and production companies and also include construction and contracting companies.

Winn Materials/McIntosh Construction

Winn Materials operations consist of two crushed stone quarries and a river terminal, while McIntosh is a complementary asphalt producer and paving company. Together, the two companies function as a vertically integrated unit. The operations of Winn/McIntosh are located in and around Clarksville, Tennessee, which is located approximately 45 miles northwest of Nashville and is Tennessee s fifth largest city.

Winn mines and produces hard rock limestone using conventional drilling, blasting and crushing methods. Winn primarily leases its properties at its two quarries located in Clarksville and in Trenton, Kentucky and pays royalties for material produced and sold from the leased properties. Winn s marine terminal business is located on the Cumberland River, adjacent to Winn s Clarksville quarry. Its dock transloads various materials by barge. Through the river terminal, Winn loads out crushed stone and also imports products such as river and granite sand and fertilizer and agricultural products for the local and regional markets. The river terminal is currently being expanded to meet growing demand for additional imported product into these markets. Crushed stone produced at Winn s quarries and products imported from the river terminal are loaded onto third party trucks for delivery to Winn s customers.

McIntosh sells asphalt to third parties and also operates its own paving business. Winn supplies most of McIntosh s crushed stone and sand used for both its asphalt production and construction needs. The Winn/McIntosh businesses sell to and provide services for residential, commercial and industrial customers. These businesses also supply and provide construction services for infrastructure and highway construction projects primarily within Montgomery County, Tennessee, including for Fort Campbell, one of the largest Army bases in the United States.

Southern Aggregates

Southern Aggregates is a sand and gravel mining company based in Denham Springs, Louisiana approximately 25 miles northeast of Baton Rouge, Louisiana. Southern operates five sand and gravel operations. Suction dredges extract sand and gravel, and the mined material is processed at plants generally located at each site. The plants separate gravel and saleable sand from waste sand and clays, and the waste is returned to mined-out sections of pits. The saleable sand and gravel material is loaded onto third party trucks for delivery to Southern s customers. Southern leases its mineral reserves and pays royalties based on its sales volumes. Southern s markets extend approximately 100 miles west and south from its operating locations, including to the cities of Baton Rouge, Lafayette and New Orleans. Southern s customers consist primarily of ready mix concrete companies, asphalt producers and contractors.

Trona Mining and Soda Ash Production Business

We own a 49% non-controlling equity interest in OCI Wyoming LLC (OCI Wyoming), which is one of the largest and lowest cost producers of soda ash in the world, serving a global market from its facility located in the Green River Basin of Wyoming. The Green River Basin geological formation holds the largest, and one of the highest purity, known deposits of trona ore in the world. Trona, a naturally occurring soft mineral, is also known as sodium sesquicarbonate and consists primarily of sodium carbonate, or soda ash, sodium bicarbonate and water. OCI Wyoming processes trona ore into soda ash, which is an essential raw material in flat glass, container glass, detergents, chemicals, paper and other consumer and industrial products. The vast majority of the world s trona reserves are located in the Green River Basin. According to historical production statistics, approximately one-quarter of global soda ash is produced by processing trona, with the remainder being produced synthetically through chemical processes. The costs associated with procuring the materials needed for synthetic production are greater than the costs associated with mining trona for trona-based production. In addition, trona-based production consumes less energy and produces fewer undesirable by-products than synthetic production.

OCI Wyoming s Green River Basin surface operations are situated on approximately 880 acres in Wyoming, and its mining operations consist of approximately 23,500 acres of leased and licensed subsurface mining area. The facility is accessible by both road and rail. OCI Wyoming uses six large continuous mining machines and ten underground shuttle cars in its mining operations. Its processing assets consist of material sizing units, conveyors, calciners, dissolver circuits, thickener tanks, drum filters, evaporators and rotary dryers.

Table of Contents

The following map provides an aerial view of OCI Wyoming s surface operations.

In trona ore processing, insoluble materials and other impurities are removed by thickening and filtering the liquor, a solution consisting of sodium carbonate dissolved in water. OCI Wyoming then adds activated carbon to filters to remove organic impurities, which can cause color contamination in the final product. The resulting clear liquid is then crystallized in evaporators, producing sodium carbonate monohydrate. The crystals are then drawn off and passed through a centrifuge to remove excess water. The resulting material is dried in a product dryer to form anhydrous sodium carbonate, or soda ash. The resulting processed soda ash is then stored in seven on-site storage silos to await shipment by bulk rail or truck to distributors and end customers. OCI Wyoming s storage silos can hold up to 65,000 short tons of processed soda ash at any given time. The facility is in good working condition and has been in service for over 50 years.

The evaporation stage of trona ore processing produces a precipitate and natural by-product called deca. Deca, short for sodium carbonate decahydrate, is one part soda ash and ten parts water. Solar evaporation causes deca to crystallize and precipitate to the bottom of the four main surface ponds at the Green River Basin facility. OCI Wyoming s deca rehydration process enables OCI Wyoming to reduce waste storage needs and convert what is typically a waste product into a usable raw material. As a result of this process, OCI Wyoming has been able to reduce the amount of short tons of trona ore it takes to produce one short ton of soda ash.

The soda ash produced is shipped by rail or truck from the Green River Basin facility. For the year ended December 31, 2014, OCI Wyoming shipped approximately 96.0% of its soda ash to customers initially via rail under a contract with Union Pacific that expires on December 31, 2017, and the plant receives rail service exclusively from Union Pacific. OCI Wyoming leases a fleet of more than 1,700 hopper cars that serve as dedicated modes of shipment to its domestic customers. For export, OCI Wyoming ships soda ash on unit trains consisting of approximately 100 cars to two primary ports: Port Arthur, Texas and Portland, Oregon. From these ports, the soda ash is loaded onto ships for delivery to ports all over the world. American Natural Soda Ash

Corporation (ANSAC) provides logistics and support services for all of OCI Wyoming s export sales. For domestic sales, OCI Chemical Co. provides similar services.

OCI Wyoming s largest customer is ANSAC, which buys soda ash (through OCI Wyoming s sales agent) and other of its member companies for further export to its customers. ANSAC takes soda ash orders directly from its overseas customers and then purchases soda ash for resale from its member companies pro rata based on each member s production volumes. ANSAC is the exclusive distributor for its members to the markets it serves. However, OCI Chemical, on OCI Wyoming s behalf, negotiates directly with, and OCI Wyoming exports to, customers in markets not served by ANSAC.

OCI Wyoming is party to nine mining leases and one license for its subsurface mining rights. Some of the leases are renewable at OCI Wyoming s option upon expiration. OCI Wyoming pays royalties to the State of Wyoming, the U.S. Bureau of Land Management and Anadarko Petroleum or its affiliates, which are calculated based upon a percentage of the quantity or gross value of soda ash and related products at a certain stage in the mining process, or a certain sum per ton of such products. These royalty payments are typically subject to a minimum domestic production volume from the Green River Basin facility, although OCI Wyoming is obligated to pay minimum royalties or annual rentals to its lessors and licensor regardless of actual sales. The royalty rates paid to OCI Wyoming s lessors and licensor may change upon renewal of such leases and license.

As a minority interest owner in OCI Wyoming, we do not operate and are not involved at all in the day-to-day operation of the trona ore mine or soda ash production plant. Our partner, OCI Resources LP manages the mining and plant operations. We appoint three of the seven members of the Board of Managers of OCI Wyoming and have certain limited negative controls relating to the company.

Aggregates/Industrial Minerals Royalty Business

We own an estimated 500 million tons of aggregates reserves located in a number of states across the country. We lease a portion of these reserves to third parties in exchange for royalty payments. The structure of these leases is similar to our coal leases, and these leases typically also require minimum rental payments in addition to royalties. See Coal and Coal-Related Properties Coal Royalty Business for a description of our royalty structure. In 2006, we bought our first aggregates reserves property on the Puget Sound in Washington State. Since that time, we have made several other aggregates reserve purchases in multiple U.S. geographies. During 2014, our aggregates lessees produced 3.5 million tons of aggregates from these properties and we received $8.7 million in aggregates royalty revenues, including overriding royalty revenues.

Oil and Natural Gas Properties

We generate oil and gas revenues from non-operated working interests, royalty interests and overriding royalty interests in producing oil and gas wells. During 2014, we generated $59.6 million in revenues from our interests in oil and gas properties. Our primary interests in oil and natural gas producing properties are our non-operated working interests located in the Williston Basin, but we also own fee mineral, royalty or overriding royalty interests in oil and gas properties in several other areas, including the Appalachian Basin and the Mississippian Lime formation. NRP owns a 51% interest in BRP LLC, which owns oil and gas mineral rights, in northern Louisiana. See BRP LLC Joint Venture.

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. 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. 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 our wells, including the cost of development and production.

Table of Contents

Our non-operated working interests are all located in the Williston Basin in North Dakota and Montana. As of December 31, 2014, we had non-operated working interests in 21,832 net acres in the basin, all of which are held by production. These assets include 6,086 net acres in the Sanish Field in Mountrail County, North Dakota that we acquired in November 2014 from an affiliate of Kaiser-Francis Oil Company. The interests acquired in that acquisition are all operated by Whiting Petroleum Corporation and include an estimated average working interest of 14.5% in approximately 196 wells that were producing as of December 31, 2014.

We own royalty interests where we have leased certain portions of our owned mineral interests to third parties primarily located in the southern portion of the Appalachian Basin and in the Mississippian Lime in Oklahoma. We also own overriding royalty interests primarily located in the Appalachian Basin in West Virginia and Pennsylvania, including in the Marcellus Shale, and in the Haynesville Shale in Louisiana.

Estimated Proved Reserves

Proved reserves are those quantities of crude oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain. In connection with the estimation of proved reserves, the term reasonable certainty implies a high degree of confidence that the quantities of crude oil, natural gas liquids and/or natural gas actually recovered will equal or exceed the estimate. Our estimated proved reserves as of December 31, 2014 were prepared by Netherland, Sewell & Associates, Inc., our independent reserve engineer. To achieve reasonable certainty, Netherland Sewell employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps including isopach and structure maps, analogy and statistical analysis, and available downhole and production data and well test data.

The following tables set forth our estimated proved and related standardized measure of discounted cash flows by reserve category as of December 31, 2014. Netherland Sewell prepared its report covering properties representing 100% of our estimated proved reserves as of December 31, 2014. Prices were calculated using the unweighted average of the first-day-of-the-month pricing for the twelve months ended December 31, 2014. These prices were then adjusted for transportation and other costs. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reserve engineers often arrive at different estimates for the same properties. A copy of Netherland Sewell s summary report is included as Exhibit 99.2 to this Annual Report on Form 10-K.

	Estimated Proved Reserves as of December 31, 2014(1)				
	Crude Oil (MBbl)	**NGLs (MBbl)**	**Natural Gas (MMcf)**	**Total Proved Reserves (MBoe)(2)**	**Standardized Measure of Discounted Cash Flows(3) (in thousands)**
Proved Developed Producing	8,918	1,093	13,069	12,189	$ 286,179
Proved Developed Non-Producing	12	5	92	32	655
Proved Undeveloped	1,053	131	1,209	1,386	18,363
Total	9,983	1,229	14,370	13,607(4)	$ 305,197

(1) Includes reserves attributable to our 51% member interest in BRP LLC.

(2) Natural gas is converted on the basis of six Mcf of gas per one Bbl of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.

(3) Standardized measure of discounted cash flows represents the present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and

regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.

(4) Includes 12,144 MBoe of estimated proved reserves attributable to our non-operated working interests in oil and natural gas properties in the Williston Basin, approximately 10% of which were proved undeveloped reserves.

Proved Undeveloped Reserves

As of December 31, 2014, our estimated proved undeveloped reserves were 1,386 MBoe. During 2014, we participated in 33 wells related to the conversion of estimated proved undeveloped reserves with associated capital expenditures of $5.2 million. During 2014, we converted 704 MBoe of estimated proved undeveloped reserves to estimated proved developed reserves. As of December 31, 2014, we had no estimated proved undeveloped reserves that have remained undeveloped for more than five years, and we expect all estimated proved undeveloped reserves reported herein will be developed within the next two years.

For additional information on our estimated proved reserves, see Note 19 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Netherland Sewell, our independent reserve engineering firm, estimated, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the Securities and Exchange Commission, 100% of our proved reserves as of December 31, 2014. The Netherland Sewell technical personnel responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. See Exhibit 99.2 included as an exhibit to this Annual Report on Form 10-K for further discussion of the qualifications of Netherland Sewell personnel.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Netherland Sewell in their reserves estimation process. In the fourth quarter, our technical team was in contact regularly with representatives of Netherland Sewell to review properties and discuss methods and assumptions used in Netherland Sewell s preparation of the year-end reserves estimates. A copy of the Netherland Sewell reserve report was reviewed by our internal technical staff prior to the inclusion of such report in this Annual Report on Form 10-K.

Our Director-Engineering and Reserves is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin and is a member of the Society of Petroleum Engineers. Prior to joining NRP, he spent nine years at DeGolyer and MacNaughton as a reservoir engineer working on multiple aspects of reserve evaluation and appraisals. The Director-Engineering and Reserves reports directly to our Vice President, Oil and Gas.

Table of Contents

Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the year ended December 31, 2014 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2014. Production and price information for the years ended December 31, 2013 and 2012 is not included, as our oil and natural gas producing activities were not material to our results of operations for those years.

	Year Ended December 31, 2014		
	Williston Basin(1)	Royalty and Overriding Royalty Interests(2)	Total
Net Production Volumes:			
Crude oil (MBbl)	578	33	611
NGLs (MBbl)	53	18	71
Natural gas (MMcf)	408	1,313	1,721
Average sales prices:			
Crude oil ($/Bbl)	$ 77.85	$ 82.91	$ 78.12
NGLs ($/Bbl)	$ 33.64	$ 34.56	$ 33.87
Natural gas ($/Mcf)	$ 5.04	$ 4.17	$ 4.37
Average costs ($/Boe):			
Production expenses	$ 13.08		$ 13.08
Ad valorem and severance taxes	$ 7.91		$ 7.91
General and administrative expense	$ 4.86		$ 4.86
DD&A expense	$ 25.73	$ 22.06	$ 24.70

(1) Represents volume, price and cost information relating to our non-operated Williston Basin working interest properties.

(2) Represents information relating to our royalty and overriding royalty interests in oil and gas properties. These interests are recorded net of costs.

For additional information on our production, sales prices and costs, see Note 19 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Drilling and Development Activities

We do not operate any wells or conduct any drilling activities. The following table sets forth information with respect to the number of net wells drilled and completed on our properties during the year ended December 31, 2014. Well information for the years ended December 31, 2013 and 2012 is not included, as our oil and natural gas producing activities were not material to our results of operations for those years. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return. Net wells represent the total of our fractional working interests or royalty interests, as applicable, owned in gross wells.

	Year Ended December 31, 2014					
	Productive		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net
Development	123	4.4	0	0	123	4.4
Exploratory	0	0	0	0	0	0
Total	123	4.4	0	0	123	4.4

Table of Contents

Producing Oil and Natural Gas Wells

The following table sets forth the gross and net producing oil and natural gas wells in which we held working interests and royalty or overriding royalty interests as of December 31, 2014. Gross wells represent the number of wells in which we own an interest. Net wells represent the total of our fractional working interests or royalty interests, as applicable, owned in gross wells.

	As of December 31, 2014							
	Working Interest Wells(1)				Royalty and Overriding Royalty Interest Wells(2)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	442	47	0	0	25	0.1	0	0
Other	0	0	0	0	100	5.2	987	76
Total	442	47	0	0	125	5.3	987	76

(1) As of December 31, 2014, we also owned non-operated working interests in 40 gross oil wells in various stages of development in the Williston Basin.

(2) 57 gross (1.4 net) natural gas and oil wells are attributable to our overriding royalty interest in the Marcellus Shale acquired in 2012. The remaining wells consist primarily of conventional oil and gas wells or coal bed methane that are located in the southern portion of the Appalachian Basin.

Undeveloped Acreage Summary

The following table contains a summary of the undeveloped gross and net acres in which we had interests as of December 31, 2014:

	Undeveloped Acres as of December 31, 2014			
	Acres Leased to NRP(1)		Net ORRI and Fee Mineral Acres	
	Gross	Net	ORRI(2)	Fee Mineral(3)
Williston Basin	610	384	0	0
Other	0	0	25,162	30,696
Total	610	384	25,162	30,696

(1) Represents mineral acres leased by third parties to NRP.

(2) Represents net acres in which we have an overriding royalty interest in the Marcellus Shale 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.

(3) Represents net fee mineral acres owned by NRP and BRP LLC and leased to third parties.

Delivery Commitments

As of December 31, 2014, we had no material delivery commitments.

BRP LLC Joint Venture

BRP LLC is a joint venture between NRP and International Paper Company, in which we own a 51% interest. As of December 31, 2014, BRP owned approximately 10 million mineral acres in 31 states. While the vast majority of the 10 million acres remain largely undeveloped, BRP currently holds 71 mineral leases and 17 cell tower leases and has an active program to identify additional opportunities to lease its minerals to operating parties. For the year ended December 31, 2014, BRP generated $8.0 million in revenue.

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 as of December 31, 2014. In addition to the leased mineral acreage, BRP holds a 1% overriding royalty interest on approximately 28,000 mineral acres in Louisiana. As of December 31, 2014, BRP owned nearly 95,000 net mineral acres of coal rights (primarily lignite and some bituminous coal) in the Gulf Coast region, of which approximately 5,800 acres are leased in Louisiana, Alabama and Texas. In addition, BRP also owns copper rights in Michigan s Upper Peninsula that are subject to a development agreement with a copper development company. BRP also holds various other mineral rights including coalbed methane, metals, aggregates, water and geothermal, in several states throughout the United States.

Significant Customers

In 2014, we had total revenues of $81.5 million from Foresight Energy LP and its affiliated companies and $48.8 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 10% of our revenue in 2014, 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 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. 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.

Our trona mining and soda ash refinery business 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 construction aggregates industry that VantaCore operates in is highly competitive and fragmented with a large number of independent local producers in operating in VantaCore s local markets. Additionally, VantaCore also competes against large private and public companies, some of which are significantly vertically integrated. Therefore, there is intense competition in a number of markets in which VantaCore operates. This significant competition could lead to lower prices and lower sales volumes in some markets, negatively affecting our earnings and cash flows.

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 aggregates reserves in fee as of December 31, 2014. We lease the remainder from unaffiliated third parties, including leasing aggregates reserves for VantaCore s construction materials business. OCI Wyoming also leases or licenses its trona reserves. As of December 31, 2014, 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.

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

Operations on our properties must be conducted 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 natural resource extraction operations are not unusual and, notwithstanding compliance efforts, we do not believe violations 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 or operations.

While it is not possible to quantify the costs of compliance with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. Our lessees in our coal and aggregates royalty businesses 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 steam coal, is subject to extensive regulation regarding the environmental impact of its power generation activities, which has affected and is expected to continue to affect demand for coal mined from our properties. Current and future proposed legislation and regulations could be adopted that will have a significant additional 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 additional substantial costs that would negatively impact the coal industry.

Table of Contents

Many of the statutes discussed below also apply to exploration and development activities associated with our interests in crude oil and natural gas properties and to the aggregates and industrial mineral mining operations in which we hold interests, including VantaCore s construction aggregates mining and production operations and OCI Wyoming s trona mining and soda ash production operations, and therefore we do not present a separate discussion of statutes related to those activities, except where appropriate.

Air Emissions

The 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, including the Cross-State Air Pollution Rule (CSAPR), regulating emissions of nitrogen oxide and sulfur dioxide, and the Mercury and Air Toxics Rule (MATS), regulating emissions of hazardous air pollutants. Installation of additional emissions control technologies and other measures required under these and other U.S. Environmental Protection Agency (EPA) regulations, including EPA s proposed rules to regulate greenhouse gas (GHG) emissions from new and existing fossil fuel-fired power plants, 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. These rules and regulations have resulted in a reduction in coal s share of power generating capacity, which has negatively impacted our lessees ability to sell coal and our coal-related revenues. Further reductions in coal s share of power generating capacity as a result of compliance with existing or proposed rules and regulations would have a material adverse effect on our coal-related revenues.

The emission of air pollutants from the exploration and development of crude oil and natural gas is also subject to the Clean Air Act and comparable state laws. In 2012, EPA published final New Source Performance Standards for volatile organic compounds and sulfur dioxide and National Emissions Standards for Hazardous Air Pollutants associated with oil and gas facilities. In January 2013, EPA granted petitions asking the agency to reconsider and revise parts of this rule. Accordingly, in September 2013, EPA issued updates to the New Source Performance Standards for the emission of volatile organic compounds from storage vessels used in crude oil and natural gas production. Similarly, in December 2014, EPA finalized rules related to emissions from gas and liquids during well completion. These rules could have an adverse effect on revenues from our interests in oil and natural gas properties.

Carbon Dioxide and Greenhouse Gas Emissions

In December 2009, EPA determined that emissions of carbon dioxide, methane, and other GHGs, present an endangerment to public health and welfare because emissions of such gases are, according to EPA, contributing to warming of the Earth s atmosphere and other climatic changes. Based on its findings, EPA has begun adopting and implementing regulations to restrict emissions of GHGs under various provisions of the Clean Air Act.

In January 2014, EPA published proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. In June 2014, EPA proposed the Clean Power Plan, which outlined a multi-factor plan to cut carbon emissions from existing electric generating units, including coal-fired power plants. Under this proposed rule, existing power plants would be required to cut their carbon dioxide emissions 30% from 2005 levels by the year 2030. The effect of the proposed rules would be to require many existing coal-fired power plants to incur substantial costs in order to comply or alternatively result in the closure of some of these plants. EPA intends to finalize these rules in the summer of 2015, both of which have been challenged by industry participants and other parties. The implementation of these rules as proposed would have a material adverse effect on the demand for coal by electric power generators.

Table of Contents

President Obama also announced an emission reduction deal with China s President Xi Jinping in November 2014. The United States pledged that by 2025 it would cut climate pollution by 26 to 28% from 2005 levels. China pledged it would reach its peak carbon dioxide emissions around 2030 or earlier, and increase its non-fossil fuel share of energy to around 20% by 2030. While there is no way to estimate the impact of this pledge, it could ultimately have an adverse effect on the demand for coal, both nationally and internationally.

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, as well as certain oil and natural gas production facilities, on an annual basis.

On January 14, 2015, EPA announced plans to propose new regulations to reduce emissions of methane from crude oil and natural gas production and transportation activities such as wells, pipelines, and valves levels by up to 45 percent by 2025 (compared to 2012 levels). EPA expects to propose the new regulations in the summer of 2015 and a final rule is expected in 2016.

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. We could become liable under federal and state Superfund and waste management statutes if our lessees are unable to pay environmental cleanup costs relating to hazardous substances. In addition, we may have liability for environmental clean-up costs in connection with our VantaCore construction aggregates and OCI Wyoming soda ash businesses and in connection with our non-operated working interests in oil and gas properties, to the extent of our proportionate interest therein.

Water Discharges

Operations conducted on our properties can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations create two permitting programs for mining operations. The National Pollutant Discharge Elimination System (NPDES) program under Section 402 of the statute is administered by the states or 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 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.

In connection with EPA s review of permits, it has sought to reduce the size of fills and to impose limits on specific conductance (conductivity) and sulfate at levels that can be unachievable absent treatment at many mines. Such actions by EPA could make it more difficult or expensive to obtain or comply with such permits, which could, in turn, have an adverse effect on our coal-related revenues.

In addition to government action, private citizens groups have continued to be active in bringing lawsuits against operators and landowners. Since 2012, several citizen suit group lawsuits have been 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 have sought penalties as well as injunctive relief that would limit future discharges of selenium, conductivity or sulfate. The federal district court for the Southern District of West Virginia has ruled in favor of the citizen suit groups in multiple suits alleging violations of the water quality standard for selenium and in two suits alleging violations of water quality standards due to discharges of conductivity. Most of these cases were resolved prior to any appeal and it is difficult to predict whether such suits will continue to be successful. However, additional rulings requiring operators to reduce their discharges of selenium, conductivity or sulfate could result in large treatment expenses for our lessees.

Since 2013, several citizen group lawsuits have been filed against landowners alleging ongoing discharges of pollutants, including selenium and conductivity, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. NRP has been named as a defendant in one of these lawsuits. 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 could result in substantial compliance costs or fines and would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations.

Drilling and development activities associated with our oil and natural gas business generate produced water. Produced water is often disposed of in underground injection control (UIC) wells that receive permits from EPA or from state agencies that have been granted authority to issue UIC issue permits by EPA. Failures or delays in getting such permits could negatively impact exploration and production activities and, in turn, adversely affect our oil and natural gas business.

Other Regulations Affecting the Mining Industry

Mine Health and Safety Laws

The operations of our lessees, VantaCore and OCI Wyoming 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 program, if a mine s rate of injuries or significant and substantial citations exceed a certain threshold. A mine that is placed in a Pattern of Violations program will receive additional scrutiny from MSHA.

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. 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.

Table of Contents

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 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. In February 2014, the federal court vacated the 2008 rule and in December 2014, OSM reinstated the previous version of the rule, without clarifying whether the previous version of the rule impacts the ability to construct excess fills. OSM has stated that it is considering future revisions to the buffer zone rule. Any revision or interpretation of the rule 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 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 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 EPA that is adverse to the mining industry.

Other Regulations Affecting the Crude Oil and Natural Gas Industry

Hydraulic Fracturing

The exploration and production companies that operate the crude oil and natural gas properties in which we have interests use hydraulic fracturing to recover oil and natural gas from tight rock formations. Hydraulic fracturing is a process customary to the oil and gas industry in which water, sand and other additives are pumped under high pressure into tight rock formations in a manner that creates or expands fractures in the rock to facilitate oil and gas recovery. While hydraulic fracturing has been used to recover oil and natural gas for decades, the practice has recently received increased scrutiny from various federal, state and local agencies, some of which have prohibited the practice or called for further study of its effects. Future requirements that limit or more strictly regulate the permitting or use of hydraulic fracturing could impact revenues from our oil and natural gas properties.

Permitting

Additionally, state agencies are generally charged with issuing permits governing the location and construction of drilling sites. Delays or failures to obtain such permits due to local land use or environmental concerns could negatively impact revenues from our oil and gas operations.

Table of Contents

Transportation

Our revenues could be negatively impacted if the Federal Energy Regulatory Commission, which approves interstate pipelines and certain gathering lines, fails to timely approve pipelines that transport oil or natural gas produced from the properties in which we own interests. Additionally, our oil and natural gas revenues could be negatively impacted by rules proposed in July 2014 by the United States Department of Transportation governing the transportation of crude oil by rail. As proposed, the rules would require thousands of railroad tank cars to be upgraded or phased out by 2017. Railroad tank car shortages resulting from the proposed rule could delay or increase the costs of transportation of crude oil from our Williston Basin non-operated working interests and negatively impact revenues from those properties.

Employees and Labor Relations

We historically have not had any employees. To carry out our operations, affiliates of our general partner employ 89 people who directly support our operations. None of these employees are subject to a collective bargaining agreement. As a result of our acquisition of VantaCore in the fourth quarter of 2014, we now employ 269 people who support VantaCore s construction aggregates mining and production 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 revenues and other income from these natural resource properties are royalties from coal, aggregates, oil and gas, timber, related transportation and processing infrastructure revenues, as well as other income from our equity investment in OCI Wyoming s trona mine and soda ash refinery operations, and revenues from the VantaCore aggregates mining and production operation purchased during 2014.

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

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. The actual amount of cash we have to distribute each quarter is reduced by payments in respect of debt service and other contractual obligations, fixed charges, maintenance capital expenditures and reserves for future operating or capital needs that the board of directors may determine are appropriate. Cash distributions are dependent primarily on cash flow, 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. To the extent our board of directors deems appropriate, it may determine to decrease the amount of the quarterly distribution.

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

As of December 31, 2014, we and our subsidiaries had approximately $1.5 billion of total indebtedness. The terms and conditions governing our indebtedness, including NRP s 9.125% senior notes, Opco s revolving credit facility, term loan and senior notes, and NRP Oil and Gas s revolving credit facility:

- require us to meet certain leverage and interest coverage ratios;
- 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 bank and 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;
- 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, borrow more money, sell assets or raise equity, and our ability to pursue acquisitions may be limited. We are required to make substantial principal repayments each year in connection with Opco s senior notes, with approximately $81 million due thereunder each year through 2018. In addition, Opco s revolving credit facility and term loan both mature in 2016. We will be required to repay or refinance the amounts outstanding under these credit facilities prior to their maturity. We may not be able to refinance these amounts on terms acceptable to us, if at all, or the borrowing capacity under Opco s revolving credit facility may be substantially reduced.

The borrowing base under NRP Oil and Gas s revolving credit facility is based on the value of our proved reserves and is redetermined on a semi-annual basis in May and October of each year. The current oil price environment or future declines in prices or reduced production from or development of our properties could result in a determination to lower the borrowing base. In such event, we may not be able to access funding under the facility necessary to operate our business or we could be required to repay any indebtedness in excess of the redetermined borrowing base.

We may not be able to refinance our debt, sell assets, borrow more money or access the bank and capital markets on terms acceptable to us, if at all. Our ability to access the capital markets may be challenging in the current commodity price environment. Our ability to comply with the financial and other restrictive covenants in

Table of Contents

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.

Coal prices continue to be severely depressed, which has negatively affected 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 and the value of our coal reserves.

Prices for both steam and metallurgical coal have declined substantially in recent years and remain at levels close to or below the level of operating costs for a number of our lessees. 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;
- changes in fuel consumption patterns of electric power generators;
- the price and availability of alternative fuels, especially natural gas;
- global economic conditions, including the strength of the U.S. dollar relative to other currencies and 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. Relatively low natural gas prices have resulted in a number of utilities switching 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. The closure of coal-fired power plants as a result of increased governmental regulations or the inability to comply with such regulations has also resulted in a decrease in the demand for steam coal.

Prices for metallurgical coal are also at multi-year lows due to global economic conditions. Our lessees produce a significant amount of the metallurgical coal that is used in both the U.S. and foreign steel industries. 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. In addition, rising exports of metallurgical coal from Australia and a strong U.S. dollar 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.

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. For the year ended December 31, 2014, we took an impairment charge of $17.6

million relating to certain of our coal related properties. 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.

Table of Contents

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 that substantially all newly constructed power plants in the United States will be fired by natural gas because of lower construction and compliance costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of rules and regulations promulgated under 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 and existing power plants are expected to further limit the construction of new coal-fired generation plants in favor of alternative sources of energy and 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 and other hazardous air pollutants could result in reduced demand for our coal, oil and natural gas.

In December 2009, EPA determined that emissions of carbon dioxide, methane, and other GHGs, present an endangerment to public health and welfare because emissions of such gases are, according to EPA, contributing to warming of the Earth s atmosphere and other climatic changes. Based on its findings, EPA has begun adopting and implementing regulations to restrict emissions of GHGs under various provisions of the Clean Air Act.

In January 2014, EPA published proposed new source performance standards for GHG emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. In June 2014, EPA proposed the Clean Power Plan, which outlined a multi-factor plan to cut carbon emissions from existing electric generating units, including coal-fired power plants. Under this proposed rule, existing power plants would be required to cut their carbon dioxide emissions 30% from 2005 levels by the year 2030. The effect of the proposed rules would be to require many existing coal-fired power plants to incur substantial costs in order to comply or alternatively result in the closure of some of these plants. EPA intends to finalize these rules in the summer of 2015, both of which have been challenged by industry participants and other parties. The implementation of these rules as proposed would have a material adverse effect on the demand for coal by electric power generators and as a result on our coal related-revenues.

In addition to EPA s GHG initiatives, there are several other federal rulemakings that are focused on emissions from coal-fired electric generating facilities, including the Cross-State Air Pollution Rule (CSAPR), regulating emissions of nitrogen oxide and sulfur dioxide, and the Mercury and Air Toxics Rule (MATS), regulating emissions of hazardous air pollutants. Installation of additional emissions control technologies and other measures required under these and other EPA regulations have made it more costly to operate many coal-fired power plants and have resulted in and are expected to continue to result in plant closures. Further reductions in coal s share of power generating capacity as a result of compliance with existing or proposed rules and regulations would have a material adverse effect on our coal-related revenues.

The emission of air pollutants from the exploration and development of crude oil and natural gas and related facilities is also subject to the Clean Air Act and comparable state laws. In 2012, EPA published final New Source Performance Standards for volatile organic compounds and sulfur dioxide and National Emissions Standards for Hazardous Air Pollutants associated with oil and gas facilities. In January 2013, EPA granted petitions asking the agency to reconsider and revise parts of this rule. Accordingly, in September 2013, EPA issued updates to the New Source Performance Standards for the emission of volatile organic compounds from storage vessels used in crude oil and natural gas production. Similarly, in December 2014, EPA finalized rules related to emissions from gas and liquids during well completion. These rules could have an adverse effect on revenues from our interests in oil and natural gas properties.

Table of Contents

In January 2015, EPA announced plans to propose new regulations to reduce emissions of methane from crude oil and natural gas production and transportation activities such as wells, pipelines, and valves levels by up to 45 percent by 2025 (compared to 2012 levels). EPA expects to propose the new regulations in the summer of 2015 and a final rule is expected in 2016. Any such rules could have a material adverse effect on our oil and natural gas revenues.

Mining operations are subject to operating risks that could result in lower revenues to us. In addition, we are subject to operating risks as a result of the VantaCore acquisition that we have not previously experienced.

Our revenues are largely dependent on the level of production of minerals from our properties, and any interruptions to the production from our properties would reduce our revenues. The level of production is subject to operating conditions or events beyond our or our lessees 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;
- mining and processing equipment failures and unexpected maintenance problems;
- the availability of equipment or parts and increased costs related thereto;
- the availability of transportation facilities and interruptions due to transportation delays;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions; and
- unexpected mine safety accidents, including fires and explosions.

As a result of recent judicial decisions and the increased involvement of the Obama Administration and 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 we might otherwise be involved. We and our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from our or their operations. If we or our lessees are pursued for these sanctions, costs and liabilities, mining operations and, as a result, our revenues could be adversely affected.

Prior to the VantaCore acquisition, we did not operate aggregates mining and production assets. VantaCore currently operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal. As an operator of these assets, we will be exposed to risks that we have not historically been exposed to in our mineral rights and royalties business. Such risks include, but are not limited to, prices and demand for construction aggregates, capital and operating expenses necessary to maintain VantaCore s operations, production levels, general economic conditions, conditions in the local markets that VantaCore serves, inclement or hazardous weather conditions and typically lower production levels in the winter months, permitting risk, fire, explosions or other accidents, and unanticipated geologic conditions. Any of these risks could result in damage to, or destruction of, VantaCore s mining properties or production facilities, personal injury, environmental damage, delays in mining or processing, reduced revenue or losses or possible legal liability. In addition, not all of these risks are reasonably insurable, and our insurance coverage contains limits, deductibles, exclusions and endorsements. Our insurance coverage may not be sufficient to meet our needs in the event of loss. Any prolonged downtime or shutdowns at VantaCore s mining properties or production facilities or material loss could have an adverse effect on our results of operations and prevent us from realizing all of the anticipated benefits of the acquisition.

Prices for crude oil and natural gas are extremely volatile. An extended decline or further declines in crude oil and natural gas prices could have an adverse effect on our results of operations

Crude oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and on numerous other factors beyond our control, including:

- domestic and foreign supply of oil and natural gas;

Table of Contents

- the level of prices and expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the actions of the Organization of Petroleum Exporting Countries with respect to oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with drilling and completion operations;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities and the resulting differentials to market index prices;
- the price and availability of alternative fuels; and
- overall domestic and global economic conditions, including the relative value of the U.S. dollar to other currencies.

Due to global oversupply of crude oil in part due to increasing U.S. production and a strong U.S. dollar, crude oil prices have fallen significantly since the first half of 2014 to their lowest levels since 2008. In addition, natural gas prices have also fallen to low levels due to record high levels of production and robust storage inventories. These markets will likely continue to be volatile in the future, and any extended period of low prices could have a material adverse effect on our results of operations from our oil and gas business.

In addition to climate change and other Clean Air Act legislation, our businesses are subject to numerous other federal, state and local laws and regulations that may limit production from our properties and our profitability.

The operations of our lessees, VantaCore and OCI Wyoming are subject to stringent health and safety standards under increasingly strict federal, state and local environmental, health and safety laws, including mine safety regulations and governmental enforcement policies. The oil and gas industry is 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 properties.

New environmental legislation, new regulations and new interpretations of existing environmental laws, including regulations governing permitting requirements, could further regulate or tax the mining 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.

Table of Contents

In addition to governmental regulation, private citizens groups have continued to be active in bringing lawsuits against coal mine operators and landowners. Since 2012, several citizen suit group lawsuits have been filed against mine operators and landowners for alleged violations of water quality standards resulting from ongoing discharges of pollutants from reclaimed mining operations, including selenium and conductivity. NRP has been named as a defendant in one of these lawsuits. The citizen suit groups have sought penalties as well as injunctive relief that would limit future discharges of these pollutants, which would result in significant expenses for our lessees. While it is too early to determine the merits or measure the impact 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 and could result in substantial compliance costs or fines.

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

Coal, aggregates and industrial minerals, and oil and natural gas reserve engineering requires subjective estimates of underground accumulations of coal, aggregates and industrial minerals, and oil and natural gas and assumptions and are by nature imprecise. Our reserve estimates may vary substantially from the actual amounts of coal, aggregates and industrial minerals, or oil and natural gas recovered 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 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;
- production levels;
- future technology improvements;
- the effects of regulation by governmental agencies; and
- geologic and mining conditions, which may not be fully identified by available exploration data.

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.

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

In 2014, we derived 20% and 12% of our total revenues and other income from Foresight Energy LP and Alpha Natural Resources, respectively. Foresight s Williamson mine alone was responsible for approximately 10% of our total revenues and other income in 2014. As a result, we have significant concentration of revenues with these lessees. 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 revenues and ability to make future distributions would be adversely affected.

Prices for soda ash are volatile. Any substantial or extended decline in soda ash 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. The prices OCI Wyoming receives for its soda ash depend on numerous factors beyond OCI Wyoming s control, including worldwide and regional economic and political conditions impacting

Table of Contents

supply and demand. Glass manufacturers and other industrial customers drive most of the demand for soda ash, and these customers experience significant fluctuations in demand and production costs. Substantial or extended declines in prices for soda ash 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.

VantaCore operates in a highly competitive and fragmented industry, which may negatively impact prices, volumes and costs. In addition, both commercial and residential construction are dependent upon the overall U.S. economy, which is recovering at a slow pace.

The construction aggregates industry is highly fragmented with a large number of independent local producers in operating in VantaCore s local markets. Additionally, VantaCore also competes against large private and public companies, some of which are significantly vertically integrated. Therefore, there is intense competition in a number of markets in which VantaCore operates. This significant competition could lead to lower prices and lower sales volumes in some markets, negatively affecting our earnings and cash flows.

In addition, commercial and residential construction levels generally move with economic cycles. When the economy is strong, construction levels rise and when the economy is weak, construction levels fall. The U.S. economy is recovering from the 2008-2009 recession, but the pace of recovery is slow. Since construction activity generally lags the recovery after down cycles, construction projects have not returned to their pre-recession levels.

We may incur unanticipated costs or delays in connection with the integration of VantaCore and future aggregates operations into our company.

There are risks with respect to the integration of VantaCore into our company that may result in unanticipated costs or delays to us. Such risks include:

- integrating additional personnel into our company, including the 269 people employed by VantaCore;
- establishing the internal controls and procedures for the acquired businesses that we are required to maintain under the Sarbanes-Oxley Act of 2002;
- consolidating other corporate and administrative functions;
- diversion of management s attention away from our other business concerns;
- loss of key employees; and
- the assumption of any undisclosed or other potential liabilities of the acquired company.

Similar risks may apply to the integration of future aggregates operations that we may acquire through the VantaCore platform. Any significant costs and delays resulting from the risks described above could cause us not to realize the anticipated benefits of these acquisitions.

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;

the pace of development and drilling and completion activities by operators;

future crude oil and natural gas prices and their differentials;

the availability of and access to takeaway and transportation;

future development costs, operating costs and property taxes;

governmental regulations; and

potential environmental and other liabilities.

Table of Contents

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 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 and other liabilities and acquire properties on an as is basis.

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

Because our reserves decline due to production, our future success and growth depend, in part, upon our ability to make acquisitions to replace reserves that are depleted. If we are unable to make acquisitions on acceptable terms, our revenues will decline as our reserves are depleted. Our ability to acquire additional interests in mineral reserves or make other acquisitions is dependent in part on our ability to access the bank and 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.

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.

We have limited control over the activities on our properties that we do not operate and are exposed to operating risks that we do not experience in the royalty business.

We do not have control over the operations of OCI Wyoming or our non-operated oil and gas working interest properties. We 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 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. 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 Foresight s 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.

Oil and gas development activities require substantial capital. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in the value of our properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We have capital expenditures and operating expenses associated with the wells in which we own working interests and are required to fund our proportionate share on any wells in which we decide to participate. 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.

Our operations and other capital resources may not provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include additional reserve based borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. If we are unable to fund our capital requirements, we may be required to decline to participate in wells, which in turn could lead to a decline in the value of our assets or a decline in our oil and natural gas reserves.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal, oil and gas, soda ash, 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

38

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, rail operations are subject to various risks that may result in a delay or lack of service at OCI Wyoming s facility, and alternative methods of transportation are impracticable or cost-prohibitive. Any substantial interruption in or increased costs related to the transportation of OCI Wyoming s 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. 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.

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, and 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.

Table of Contents

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.

Our 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. In addition, lessees move on and off of our properties over the course of any given year in accordance with their mine plans. 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.

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 Related to Our Structure

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

Table of Contents

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.

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.

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 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 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 material 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.

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.

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. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department s proposed Treasury Regulations allowing a similar monthly simplifying convention are not final and 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.

Table of Contents

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.

Item 1B. ***Unresolved Staff Comments***
None.

Table of Contents

Item 2. ***Properties*.**

The information required by this Item is included under Item 1. Business in this Annual Report on Form 10-K and is 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***

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

Table of Contents

PART II

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

NRP Common Units and Cash Distributions

Our common units are listed and traded on the NYSE under the symbol NRP . As of February 23, 2015**,** there were approximately 43,400 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 1, 2013 to December 31, 2014, 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**
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
2014					
First Quarter	$ 20.72	$ 14.80	$ 0.3500	05/05/2014	05/14/2014
Second Quarter	$ 16.57	$ 12.78	$ 0.3500	08/05/2014	08/14/2014
Third Quarter	$ 16.91	$ 12.56	$ 0.3500	11/05/2014	11/14/2014
Fourth Quarter	$ 13.83	$ 7.97	$ 0.3500	02/05/2015	02/13/2015

Cash Distributions to Partners

	General Partner(1)	Limited Partners(2)	Total Distributions
		(in thousands)	
2013 Distributions	$ 4,930	$ 241,588	$ 246,518
2014 Distributions	$ 3,241	$ 158,801	$ 162,042

(1) Represents distributions on our general partner s 2% general partner interest in us.

(2) Includes distributions on 1,560,000 common units held by our general partner.

Unregistered Sales of Equity Securities

As previously reported, in connection with the closing of the VantaCore acquisition, on October 1, 2014, we issued 2,426,690 common units to certain of the owners of VantaCore in exchange for their interests in VantaCore and VantaCore GP upon closing of the acquisition. The aggregate offering price of the common units as of the date of issuance was approximately $31.6 million. On December 4, 2014, we issued an additional 813 units to certain of the former owners of VantaCore in connection with a post-closing adjustment to the purchase price for the acquisition. The aggregate offering price of such additional common units as of the date of issuance was approximately $8,500. Such common units were issued and sold in reliance upon an exemption from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof.

47

Table of Contents

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 Annual Reports on Form 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. Selected Financial Data For the Years Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
	(in thousands, except per unit data)				
Total revenues and other income	$ 399,752	$ 358,117	$ 379,147	$ 377,683	$ 301,401
Asset impairments	$ 26,209	$ 734	$ 2,568	$ 161,336	$
Income from operations	$ 188,919	$ 236,236	$ 267,165	$ 104,135	$ 196,061
Net income	$ 108,830	$ 172,078	$ 213,355	$ 54,026	$ 154,461
Basic and diluted net income per limited partner unit	$ 0.94	$ 1.54	$ 1.97	$ 0.50	$ 1.54
Distributions paid ($ per unit)	$ 1.40	$ 2.20	$ 2.20	$ 2.17	$ 2.16
Weighted average number of common units outstanding	113,262	109,584	106,028	106,028	81,917
Cash from operations	$ 210,755	$ 247,074	$ 271,408	$ 305,574	$ 258,694
Distributable cash flow(1)	$ 217,710	$ 309,394	$ 298,899	$ 311,174	$ 260,274
Adjusted EBITDA(1)	$ 300,322	$ 340,345	$ 328,116	$ 329,660	$ 253,074
Balance sheet data:					
Cash and cash equivalents	$ 50,076	$ 92,513	$ 149,424	$ 214,922	$ 95,506
Total assets	$ 2,444,724	$ 1,991,856	$ 1,764,672	$ 1,665,649	$ 1,664,036
Long-term debt	$ 1,394,240	$ 1,084,226	$ 897,039	$ 836,268	$ 661,070
Partners capital	$ 720,155	$ 616,789	$ 617,447	$ 644,915	$ 825,180

(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 in order to make quarterly cash distributions 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, plus returns on unconsolidated equity investments, proceeds from sales of assets, and returns on direct financing lease and contractual overrides. 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.

Table of Contents

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

	Year Ended December 31,				
	2014	2013	2012 (in thousands)	2011	2010
Net cash provided by operating activities	$ 210,755	$ 247,074	$ 271,408	$ 305,574	$ 258,694
Returns on unconsolidated equity investments	3,633	48,833			
Returns on direct financing lease and contractual overrides	1,904	2,558	2,669		
Proceeds from sales of assets	1,418	10,929	24,822	5,600	1,580
Distributable cash flow	$ 217,710	$ 309,394	$ 298,899	$ 311,174	$ 260,274

Adjusted EBITDA

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

Reconciliation of Net income to Adjusted EBITDA

	Year Ended December 31,				
	2014	2013	2012 (in thousands)	2011	2010
Net income	$ 108,830	$ 172,078	$ 213,355	$ 54,026	$ 154,461
Less equity and other unconsolidated investment income	(41,416)	(34,186)			
Add distributions from unconsolidated affiliates	46,638	72,946			
Add depreciation, depletion and amortization	79,876	64,377	58,221	65,118	56,978
Add asset impairments	26,209	734	2,568	161,336	
Add interest expense, gross	80,185	64,396	53,972	49,180	41,635
Adjusted EBITDA	$ 300,322	$ 340,345	$ 328,116	$ 329,660	$ 253,074

Adjusted 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 Item 7. 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.

Table of Contents

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 and the financial statements and footnotes included elsewhere in this Annual Report on Form 10-K for the year ended December 31, 2014.

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

We engage principally in the business of owning, managing and leasing a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, crude oil and natural gas, construction aggregates, frac sand and other natural resources. Executing on our plans to diversify our business, we have completed over $900 million in acquisitions since January 2013. For the year ended December 31, 2014, we recorded revenues and other income of $399.8 million and Adjusted EBITDA of $300.3 million. Approximately $226.7 million (57%) of our 2014 revenues and other income were attributable to coal-related sources, and $173.0 million (43%) of our revenues and other income were attributed to non-coal-related sources. Adjusted EBITDA is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA to net income, see Item 6. Selected Financial Data Non-GAAP Financial Measures Adjusted EBITDA.

Our coal reserves are located in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. We do not operate any coal mines, but lease our coal reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell our reserves in exchange for royalty payments. We also own and manage infrastructure assets that generate additional revenues, primarily in the Illinois Basin.

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

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

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

Current Liquidity Position

As of December 31, 2014, we had $100 million in available borrowing capacity under Opco s revolving credit facility, $27 million available under the NRP Oil and Gas revolving credit facility and $50.1 million in cash.

We have $80.9 million in principal payments due on NRP Operating s senior notes each year through 2018, and NRP Operating s revolving credit facility and term loan facility both mature in 2016. While we believe we have sufficient liquidity to meet our current financial needs, we will be required to repay or refinance the amounts outstanding under Opco s credit facilities prior to their maturity. While we believe we will be able to refinance these amounts, we may not be able to do so on terms acceptable to us, if at all, or the borrowing capacity under Opco s revolving credit facility may be substantially reduced. Our ability to refinance these amounts may depend in part on our ability to access the debt or equity capital markets, which will be challenging in the current commodity price environment. See Liquidity and Capital Resources for a further description of our indebtedness, cash flows and capital expenditures.

Current Results/Market Outlook

Our revenues and other income from sources other than coal represented 43% of our total revenues and other income in 2014, as compared to 23% of total revenues and other income in 2013. Although our total revenues and other income for 2014 increased over 2013, our coal-related revenues were down 17% compared to the same period. The majority of the decrease in coal-related revenues was due to lower Appalachian coal royalty revenues, which were down approximately 19% from 2013. During 2014, our investment in OCI Wyoming s trona mining and soda ash production operations contributed $41.4 million in other income, up $7.2 million from 2013, and our oil and gas revenues increased to $59.6 million, triple our oil and gas revenues in 2013.

The coal markets remained challenged during the year and do not currently show signs of recovery. Although thermal coal prices continue to be depressed, we believe that thermal coal production from our properties in the low-cost Illinois Basin will continue to remain strong in spite of the weak thermal markets. We expect the markets for thermal coal from our other regions to remain weak during 2015. We continue to have substantial exposure to metallurgical coal, from which we derived approximately 40% of our coal royalty revenues and 32% of the related production during 2014. The first quarter 2015 benchmark price for metallurgical coal remains at a multi-year low, and the global metallurgical coal market continues to suffer from oversupply in addition to reduced demand from China and a relatively strong U.S. dollar. We do not anticipate that metallurgical coal prices will recover in 2015. While we have not been significantly impacted so far by the various metallurgical coal mine idlings announced during the second half of 2014, additional mine idlings resulting in reductions of production of metallurgical coal from our properties may occur in 2015 if prices remain at current levels. In addition, if coal prices continue to remain depressed for an extended period of time, the lessees on some of our coal properties may close some of their mines causing some of our coal properties to be impaired.

Our trona mining and soda ash refinery investment performed in line with our expectations during 2014. The international market for soda ash continues to grow, as global production capacity for high-cost synthetic soda ash continues to be reduced, and OCI Wyoming s sales through ANSAC were better than expected. Domestic sales volumes, which are typically sold at higher prices than soda ash sold internationally, have remained relatively stable. The cash we receive from OCI Wyoming is in part determined by the quarterly distribution declared by OCI Resources LP. In February 2015, OCI Resources LP paid a quarterly distribution of $0.5315 per common unit with respect to the fourth quarter of 2014, representing a slight increase over the distribution paid with respect to the third quarter of 2014. OCI Resources LP also announced its intention to increase its distributions with respect to 2015 by 3% to 6%.

VantaCore s construction aggregates mining and production business is largely dependent on the strength of the local markets that it serves. Its operations based in Clarksville, Tennessee and Baton Rouge, Louisiana will depend on the pace of commercial and residential construction in those areas, each of which has been slowly recovering from the 2008-2009 recession. VantaCore s Laurel Aggregates operation in southwestern Pennsylvania serves many of the producers and oilfield service companies operating in the Marcellus and Utica Shales. To the extent that the pace of exploration and development of natural gas in those areas slows due to low natural gas prices, we expect that VantaCore s business will be affected. In addition, VantaCore s business is seasonal, with lower production and sales expected during the first quarter of each year due to winter weather.

Table of Contents

Global oil prices have declined significantly since the second quarter of 2014 due to increased oil supply driven by robust onshore U.S. development activity, coupled with reduced global demand and a strong U.S. dollar. Natural gas prices are also low due to record levels of production and high storage inventories. As of the date of this filing, we have not hedged any of our future oil or natural gas production and, as a result, our oil and gas revenues will continue to be impacted by the current price environment. However, we are able to manage the capital expenditures associated with our Williston Basin non-operated working interest properties by evaluating well proposals on a well-by-well basis. We will continue to monitor the development programs of the operators of these properties and manage the capital expenditures associated with those properties by only participating in wells that are expected to provide acceptable economic returns.

Political, Legal and Regulatory Environment Affecting Our Coal Business

The political, legal and regulatory environment continues to be difficult for the coal industry. The Environmental Protection Agency (EPA) has used its authority to create significant delays in the issuance of new permits and the modification of existing permits, which has led to substantial delays and increased costs for coal operators. In addition, the electric utility industry, which is the most significant end-user of domestic coal, is subject to extensive regulation regarding the environmental impact of its power generation activities. In January 2014, EPA published proposed new source performance standards for GHG emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. In June 2014, EPA proposed the Clean Power Plan, which outlined a multi-factor plan to cut carbon emissions from existing electric generating units, including coal-fired power plants. Under this proposed rule, existing power plants would be required to cut their carbon dioxide emissions 30% from 2005 levels by the year 2030. The effect of the proposed rules would be to require many existing coal-fired power plants to incur substantial costs in order to comply or alternatively result in the closure of some of these plants. EPA intends to finalize these rules in the summer of 2015, both of which have been challenged by industry participants and other parties. The implementation of these rules as proposed would have a material adverse effect on the demand for coal by electric power generators and as a result on our coal related-revenues.

In addition to EPA s GHG initiatives, there are several other federal rulemakings that are focused on emissions from coal-fired electric generating facilities, including the Cross-State Air Pollution Rule (CSAPR), which regulates emissions of nitrogen oxide and sulfur dioxide, and the Mercury and Air Toxics Rule (MATS), which regulates emissions of hazardous air pollutants. Installation of additional emissions control technologies and other measures required under these and other EPA regulations have made it more costly to operate many coal-fired power plants and have resulted in and are expected to continue to result in plant closures. Further reductions in coal s share of power generating capacity as a result of compliance with existing or proposed rules and regulations would have a material adverse effect on our coal-related revenues.

Significant Acquisitions

Sanish Field. On November 12, 2014, we completed the purchase of a 40% member interest in Kaiser-Whiting, LLC (Kaiser LLC) for $339 million, subject to customary post-closing purchase price adjustments. Effective November 13, 2014, NRP Oil and Gas withdrew as a member of Kaiser LLC and an undivided 40% interest in Kaiser LLC s assets was distributed out of Kaiser LLC and assigned directly to NRP Oil and Gas. The assets distributed to us included non-operated working interests in approximately 6,086 net acres with an average working interest of approximately 14.5%. The assets, located in the Sanish Field in Mountrail County, North Dakota, are all held by production and include 196 producing oil and gas wells as of December 31, 2014. See Note 3. Significant Acquisitions to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

VantaCore Partners. On October 1, 2014, we completed the acquisition of VantaCore, a privately held company specializing in the construction materials industry, for $201 million in cash and common units, subject to customary post-closing purchase price adjustments. Headquartered in Philadelphia, Pennsylvania, VantaCore operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal.

Table of Contents

VantaCore s current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana. See Note 3. Significant Acquisitions to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Sundance. In December 2013, we acquired non-operated working interests in oil and gas properties in the Williston Basin of North Dakota, including properties producing from the Bakken/Three Forks play, from Sundance Energy, Inc. for $29.4 million, following post-closing purchase price adjustments. The properties, which are all held by production are located in McKenzie, Mountrail and Dunn counties and are actively being developed.

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

OCI Wyoming. In January 2013, we acquired a non-controlling equity interest in OCI Wyoming, an operator of a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming, from Anadarko Holding Company and its subsidiary, Big Island Trona Company for $292.5 million. The acquisition agreement provides for up to the net present value of $50 million in additional contingent consideration payable by us should certain performance criteria be met as defined in the purchase and sales agreement in any of 2013, 2014 or 2015. As of December 31, 2014 we had accrued $14.5 million for contingent consideration payments, of which we expect to pay $3.8 million to Anadarko with respect to 2014.

Critical Accounting Policies

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. See Note 2. Summary of Significant Accounting Policies to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K. The following critical accounting policies are affected by estimates and assumptions used in the preparation of Consolidated Financial Statements.

Equity Investments

We account for non-marketable investments using the equity method of accounting if the investment gives us the ability to exercise significant influence over, but not control of, an investee. Significant influence generally exists if we have an ownership interest representing between 20% and 50% of the voting stock of the investee. We account for our investment in OCI Wyoming using this method.

Under the equity method of accounting, investments are stated at initial cost and are adjusted for subsequent additional investments 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, then to 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 its estimated useful life while indefinite-lived intangibles, if any, and goodwill are 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.

Our carrying value in an equity method investee company is reflected in the caption Equity and other unconsolidated investments in our Consolidated Balance Sheets. Our adjusted share of the earnings or losses of the investee company is reflected in the Consolidated Statements of Comprehensive Income as revenues and other income under the caption Equity and other unconsolidated investment income. These earnings are generated from natural resources, which are considered part of our 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.

Revenues

Coal Related Revenues. Coal related revenues consist primarily of royalties as well as transportation and processing fees. 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. 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 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, we receive a fixed price per ton for all material transported on the beltlines.

Oil and Gas Revenues. Oil and gas related revenues consist of revenues from our non-operated working interests, royalties and overriding royalties. 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 our wells, including the cost of development and production. Oil and gas royalty revenues are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. Also, included within oil and gas royalties are lease bonus payments, which are generally paid upon the execution of a lease.

Aggregates and Industrial Minerals Related Revenues. Aggregates and industrial minerals related revenues consist primarily of revenues generated in VantaCore s construction aggregates business, royalties and overriding royalties. Revenues from the sale of aggregates, gravel, sand and asphalt are recorded based upon the transfer of product at delivery to customers, which generally occurs at the quarries or asphalt plants. Aggregates and industrial minerals royalty and overriding 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. Revenues from long-term construction contracts are recognized on the percentage-of-completion method, measured by the percentage of total costs incurred to date to the estimated total costs for each contract. That method is used since we consider total cost to be the best available measure of progress on the contracts. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are determined. Changes in job performance, job conditions and estimated profitability, including those arising from final contract settlements, which result in revisions to job costs and profits are recognized in the period in which the revisions are determined. Contract costs include all direct job costs and those indirect costs related to contract performance, such as indirect labor, supplies, insurance, equipment maintenance and depreciation. General and administrative costs are charged to expense as incurred.

Deferred Revenue

Most of our coal and aggregates 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 revenue when the lessee recoups the minimum payment through production or in the period immediately following the expiration of the lessee s ability to recoup the payments.

Table of Contents

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 reported to us 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 us 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.

Share-Based Payment

We account for awards relating to our Long-Term Incentive Plan 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 our 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.

Asset Impairment

We have developed procedures to periodically evaluate our 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. A long-lived asset is deemed impaired when the future expected undiscounted cash flows from its use and disposition is less than the assets carrying value. Impairment is measured based on the estimated fair value, which is usually determined based upon the present value of the projected future cash flow compared to the assets carrying value. 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 and the potential for further declines in oil and natural gas prices, we intend to closely monitor our coal and oil and gas assets, 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. During 2014, we recorded impairment expense of $26.9 million on certain of our coal reserves, a preparation plant, intangible assets and aggregates properties. For further discussion relating to our 2014 impairments see Note 7. Plant and Equipment, Note 8. Minerals Rights and Note 9. Intangible Assets to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K

We evaluate our 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.

In accordance with FASB accounting and disclosure guidance for goodwill, we test our recorded goodwill for impairment annually or more often if indicators of potential impairment exist, by determining if the carrying value of a reporting unit exceeds its estimated fair value. Factors that could trigger an interim impairment test include, but are not limited to, underperformance relative to historical or projected future operating results or significant changes in our overall business, industry, or economic trends.

Table of Contents

Business Combinations

For purchase acquisitions accounted for as a business combination, we are 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.

Recent Accounting Pronouncements

In May 2014, the FASB amended revenue recognition topics and created a new topic relating to revenue recognition that will supersede existing guidance under U.S. GAAP. The core principle of the new guidance is to recognize revenue when promised goods or services are transferred to the customer and in an amount that reflects the consideration expected in exchange for those goods or services. To achieve this core principle, an entity should (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract and (5) recognize revenue when each performance obligation is satisfied. The guidance also specifies the accounting for some costs to obtain or fulfill a contract with a customer. Disclosure requirements include sufficient qualitative and quantitative information to enable financial statement users to understand the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The new topic is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The guidance allows for either full adoption or a modified retrospective adoption. We are currently evaluating the requirements to determine the impact, if any, of this new topic on its financial position, results of operations and cash flows.

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.

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Adjusted EBITDA

Adjusted EBITDA declined 12% in 2014 to $300.3 million from $340.3 million generated in 2013. The decrease is mainly related to the special distribution of $44.8 million received in 2013 from OCI Wyoming as well as lower coal related revenues offset by higher earnings from our investments in aggregates and oil and gas. Adjusted EBITDA is a non-GAAP financial measure. See Item 6. Selected Financial Data Non-GAAP Financial Measures Adjusted EBITDA for an explanation of adjusted EBITDA and a reconciliation of this measure to net income.

Distributable Cash Flow

Distributable cash flow for 2014 decreased by $91.7 million, or 30%, from 2013 to $217.7 million. This change was due primarily to a $44.8 million special distribution received from OCI Wyoming in 2013, declines in the coal business, and an additional $21.0 million of interest paid in 2014 that resulted in a $36.3 million decrease in net cash provided by operations relative to 2013 and also a $9.5 million difference in proceeds from the sale of assets. Distributable cash flow is a non-GAAP financial measure. See Item 6. Selected Financial Data Non-GAAP Financial Measures Distributable Cash Flow for an explanation of distributable cash flow and a reconciliation of this measure to net cash provided by operating activities.

Table of Contents

Coal Related Revenues and Production

	For the Years Ended December 31, 2014	2013	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
	(Unaudited)			
Regional Statistics				
Coal royalty production (tons)				
Appalachia:				
Northern	9,339	11,505	(2,166)	(19)%
Central	20,092	20,801	(709)	(3)%
Southern	3,914	4,151	(237)	(6)%
Total Appalachia	33,345	36,457	(3,112)	(9)%
Illinois Basin	13,177	13,087	90	1%
Northern Powder River Basin	2,844	2,778	66	2%
Gulf Coast	1,093	970	123	13%
Total	50,459	53,292	(2,833)	(5)%
Average coal royalty revenue per ton				
Appalachia:				
Northern	$ 0.92	$ 1.27	$ (0.35)	(27)%
Central	4.46	5.05	(0.59)	(12)%
Southern	5.18	6.30	(1.12)	(18)%
Total Appalachia	3.55	4.00	(0.44)	(11)%
Illinois Basin	4.10	4.28	(0.18)	(4)%
Northern Powder River Basin	2.74	2.72	0.02	1%
Gulf Coast	3.47	3.39	0.08	2%
Combined average gross royalty per ton	$ 3.65	$ 3.99	$ (0.34)	(9)%
Coal royalty revenues				
Appalachia:				
Northern	$ 8,621	$ 14,643	$ (6,022)	(41)%
Central	89,627	105,004	(15,377)	(15)%
Southern	20,292	26,156	(5,864)	(22)%
Total Appalachia	118,540	145,803	(27,263)	(19)%
Illinois Basin	54,049	56,001	(1,952)	(3)%
Northern Powder River Basin	7,804	7,569	235	3%
Gulf Coast	3,793	3,290	503	15%
Total	$ 184,186	$ 212,663	$ (28,477)	(13)%
Other coal related revenues				
Override revenue	$ 4,601	$ 10,372	$ (5,771)	(56)%
Transportation and processing fees	22,048	22,519	(471)	(2)%
Minimums recognized as revenue	6,659	6,528	131	2%
Condemnation payment		10,370	(10,370)	100%
Coal bonus payment	98		98	100%
Reserve swap	5,690	8,149	(2,459)	(30)%
Wheelage	3,442	3,593	(151)	(4)%

Total	$ 42,538	$ 61,531	$ (18,993)	(31)%
Total coal related revenues	$ 226,724	$ 274,194	$ (47,470)	(17)%

Table of Contents

Total coal related revenues. Total coal related revenues comprised approximately 57% and 77% of our total revenues and other income for the years ended December 31, 2014 and 2013, respectively. The following is a discussion of the major categories of coal related revenue:

Coal royalty revenues and production. Coal royalty revenues comprised approximately 46% and 59% of our total revenues and other income for the years ended December 2014 and 2013, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Coal royalty revenues decreased $27.3 million or 19% for the year ended December 31, 2014 compared to the same period of 2013, while production decreased 3.1 million tons or 9%.

Production from our properties in the Central Appalachian region decreased by 3%. This decrease was primarily due to a greater proportion of mining on adjacent property and some lessees temporarily idling production on our property. In addition, pricing realized by our lessees for both thermal and metallurgical coal in Central Appalachia is generally below the levels received in the same period in 2013, causing a larger percentage decrease in coal royalty revenues compared to the decrease in production.

The Southern Appalachian region also had decreased production and coal royalty revenues. This was due to a new lessee being slower in building its production after succeeding a former lessee and one lessee temporarily idling a mining unit on our property. In general our lessees received lower sales prices for both thermal and metallurgical coal causing a larger percentage decrease in coal royalty revenue compared to the decrease in production.

With respect to Northern Appalachia, for the year ended December 31, 2014 there was a decrease in coal royalty revenues and production. These decreases were primarily due to the net effect of two longwall mines having a greater proportion of their production on adjacent property in 2014 in the normal course of its mining plan.

Illinois Basin. Coal royalty revenues for the year ended December 31, 2014 decreased 3% when compared to the same period in 2013, while production was nearly constant. The Williamson mine in Illinois had lower production as did one of our properties in Indiana. These decreases were offset by higher production at the Hillsboro mine and the Macoupin mine where an additional mining unit was added. We also received increased revenue from a coal reserve acquisition completed in June 2014.

Northern Powder River Basin. Coal royalty revenues and production on our Western Energy property were about the same for the year ended December 31, 2014 when compared to 2013.

Gulf Coast. Coal royalty revenues and production slightly increased for the year ended December 31, 2014 compared to the same period in 2013, due to one lessee having a greater proportion of mining on our property.

Other coal related revenues. Other coal related revenues for the year ended December 31, 2014 decreased 31% compared to the same period in 2013. The following is a discussion of the revenues derived from each of the major sources of other coal-related revenue:

Override revenues for the year ended December 31, 2014 decreased by 56% compared to the same period in 2013 primarily due to one lessee moving its mining operations from an area on which we receive an overriding royalty onto property on which we receive coal royalty revenues, another lessee exhausting the reserves subject to the override and other lessees mining less on the area subject to our overriding royalty.

Transportation and processing fees decreased by $0.5 million or 2%, for the year ended December 31, 2014, when compared to the same period in 2013. The decrease is primarily due to the temporary idling of two processing facilities in response to market conditions which was partially offset by increased tonnage put through our Macoupin facilities.

Minimums recognized as revenue were about the same for both years.

During the year ended December 31, 2014 we also recognized revenue of $5.7 million related to a reserve swap completed in the third quarter. During 2013 we recognized $8.1 million on a similar swap. In addition, 2013 included a condemnation payment of $10.4 million.

Table of Contents

Wheelage revenue decreased by 4% for the year ended December 31, 2014 compared to the same period in 2013. This increase was due to the normal fluctuations of tonnage that are subject to wheelage charges.

Aggregates and Industrial Minerals Revenues, and Other Related Income

	For the Years Ended December 31, 2014	2013	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
	(Unaudited)			
VantaCore:				
Tonnage sold	2,295	N/A	N/A	N/A
Revenues	$ 42,051	N/A	N/A	N/A
Operating expenses	$ 32,309	N/A	N/A	N/A
Royalty revenues	$ 12,073	$ 13,479	$ (1,406)	(10)%
Total aggregates and industrial minerals related revenues	$ 54,124	$ 13,479	$ 40,645	302%
Soda ash revenues and distributions:				
Equity and other unconsolidated investment earnings	$ 41,416	$ 34,186	$ 7,230	21%
Cash distributions received from OCI Wyoming	$ 46,638	$ 72,946	$ (26,308)	(36)%

Total aggregates and industrial minerals revenues, and other related income. Total aggregates related revenues, and other related income represented approximately 24% and 13% of our total revenues and other income for both periods ended December 31, 2014 and 2013, respectively. The following is a discussion of the major categories of these revenues:

VantaCore operating revenues contributed $42.1 million. We acquired VantaCore on October 1, 2014.

Aggregates and industrial minerals related revenues decreased 10% for 2014. This decrease is primarily due to one of our lessees moving from property on which we receive royalty revenue to property on which we receive overriding royalty revenue and another lessee temporarily idling its operation in early 2014. This decrease was offset by an increase in override revenues of approximately $2.0 million in our overriding royalty revenues from frac sand properties, the remaining increase is due to override revenues increasing on our Washington aggregates property due to a lessee moving from our owned property to an area subject to an override.

Equity and other unconsolidated investment earnings. Income from our investment in the OCI Wyoming trona mining and soda ash production business was $41.4 million for the year ended December 31, 2014, and we received $46.6 million in cash distributions during the year. For the same period in 2013, we recorded equity income of $34.2 million and received $72.9 million in cash, which included a one-time special distribution of $44.8 million. The increase in equity income of 21% over 2013 is due to improved earnings from OCI Wyoming in 2014 over 2013.

Table of Contents

Oil and Gas Revenues

	For the Years Ended December 31, 2014	2013	Increase (Decrease)	Percentage Change
	(Dollars in thousands, except per unit data)			
	(Unaudited)			
Williston Basin non-operated working interests:				
Production volumes:				
Oil (MBbl)	578	N/A	N/A	N/A
Natural gas (Mcf)	408	N/A	N/A	N/A
NGL (MBoe)	53	N/A	N/A	N/A
Average sales price per unit:				
Oil (Bbl)	$ 77.85	N/A	N/A	N/A
Natural gas (Mcf)	$ 5.04	N/A	N/A	N/A
NGL (Boe)	$ 33.64	N/A	N/A	N/A
Revenues:				
Oil	$ 44,995	N/A	N/A	N/A
Natural gas	2,056	N/A	N/A	N/A
NGL	1,783	N/A	N/A	N/A
Total	$ 48,834	N/A	N/A	N/A
Other oil and gas revenues:				
Royalty and overriding royalty revenues	10,732	N/A	N/A	N/A
Total oil and gas revenues	$ 59,566	$ 17,080	$ 42,486	249%

Oil and gas revenues increased $42 million for the year ended December 31, 2014 when compared to the year ended December 31, 2013. The increase in revenues is due to a full year of revenues from our non-operated working interests in the Williston Basin that were acquired the second half of 2013. In addition, our 2014 results include revenues attributable to our Sanish Field properties acquired on November 12, 2014.

Our average oil price received from our Williston Basin properties for the year ended December 31, 2014 was $77.85.

Due to the decline in oil prices in the fourth quarter of 2014, our average price for the fourth quarter decreased to $63.17 which represents an 18.9% reduction as compared to full year.

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

Adjusted EBITDA

Adjusted EBITDA increased 4% to $340.3 million mainly due to our investment in OCI Wyoming that generated $72.9 million that more than offset the significant declines of $69.2 million that we saw from our coal related revenues. Adjusted EBITDA is a non-GAAP financial measure. See Item 6. Selected Financial Data Non-GAAP Financial Measures Adjusted EBITDA for an explanation of adjusted EBITDA and a reconciliation of this measure to net income.

Distributable Cash Flow

Distributable cash flow increased by $10.5 million, or 4%, to $309.4 million mainly due to distributions of $72.9 million from OCI Wyoming in 2013, offset by lower cash flows from coal related assets and proceeds from the sale of a preparation plant in 2012 of $4.7 million. Distributable cash flow is a non-GAAP financial measure. See Item 6. Selected Financial Data Non-GAAP Financial Measures Distributable Cash Flow for an explanation of distributable cash flow and a reconciliation of this measure to net cash provided by operating activities.

Table of Contents

Coal Related Revenues and Production

	For the Years Ended December 31, 2013	2012	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
	(Unaudited)			
Regional Statistics				
Coal royalty 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 coal royalty revenue per ton				
Appalachia				
Northern	$ 1.27	$ 1.50	$ (.23)	(15%)
Central	5.05	5.99	(.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	(.10)	(2)%
Northern Powder River Basin	2.72	3.58	(.86)	(24)%
Gulf Coast	3.39	2.60	.79	30%
Combined average gross royalty per ton	$ 3.99	$ 4.79	(.80)	(17)%
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)%
Other coal related revenues				
Override revenue	$ 10,372	$ 13,979	$ (3,607)	(26)%
Transportation and processing fees	22,519	27,354	(4,835)	(18)%
Minimums recognized as revenue	6,528	23,029	(16,501)	(72)%
Condemnation payments	10,370	8,463	1,907	23%
Gain on Sale of Assets		4,715	(4,715)	(100)%
Reserve swap	8,149		8,149	100%
Wheelage	3,593	5,078	(1,485)	(29)%

Total	$ 61,531	$ 82,618	$ (21,087)	(26)%
Total coal related revenues	$ 274,194	$ 343,352	$ (69,158)	(20)%

Table of Contents

Total coal related revenues. Total coal related revenues comprised approximately 77% and 91% of our total revenues and other income for the years ended December 31, 2013 and 2012, respectively. The following is a discussion of the major categories of coal related revenue:

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

Appalachia. Coal royalty revenues decreased $55.7 million or 28% for the year ended December 31, 2013 compared to the same period of 2012, while production decreased 3.8 million tons or 10%.

Production from our properties in the Central Appalachian region declined by 20% due to a combination of the idling of mining units or mines, lower sales volumes from mines on our property and some mining units moving off of our property to adjacent properties in the normal course of their mine plans. In addition, pricing realized by our lessees for both thermal and metallurgical coal in Central Appalachia is generally below the levels of the same period in 2012, causing a higher percentage decrease in coal royalty revenues compared to the decrease in production.

The Southern Appalachian region also had increased production but decreased coal royalty revenues. The increased production was due to one of our lessees having more normal production for 2013 after a slower start in 2012 after making repairs to its preparation plant that was damaged by a tornado in 2011. In addition prices from the metallurgical sales from our properties were lower than the same period in 2012, which contributed to the decrease in coal royalty revenue.

With respect to Northern Appalachia, during the year ended December 31, 2013 there was also a decrease in coal royalty revenue while we had an increase in production of 1.0 million tons or 10%. The increase in tonnage was due to some lessees having a higher proportion of production on our properties. Those increases were generally from leases with lower revenue per ton which caused the decrease in coal royalty revenue.

Illinois Basin. Coal royalty revenues for the year ended December 31, 2013 increased $6.5 million or 13% when compared to the same period in 2012, and production increased by 1.8 million tons, or 16%. The increased production was primarily due to production from the Hillsboro mine which operated its longwall for the entire year of 2013 after starting operation in 2012. This increase in production was partially offset by lower production from the Williamson mine and lower production from the Macoupin mine which idled one of its producing units in early 2013.

Northern Powder River Basin. Coal royalty revenues decreased on our Western Energy property despite having higher production in 2013. The higher production was due to the normal variations in production that occur on our checkerboard ownership. The lower coal royalty revenue 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 revenue and production for the year ended December 31, 2013 increased compared to the same period in 2012 due to a mine having a greater proportion of production on our property in 2013.

Other coal related revenues. Other coal related revenues for the year ended December 31, 2013 decreased 26% compared to the same period in 2012. The following is a discussion of the revenues derived from each of the major sources of other coal-related revenue:

Override revenue for the year ended December 31, 2013 decreased by 26% compared to the same period in 2012 due to one lessee moving its mining operations from an area on which we receive an overriding royalty onto property on which we receive coal royalty revenue, one lessee exhausting the reserves subject to the override and other lessees mining fewer tons on properties on which we receive an overriding royalty.

Transportation and processing fees decreased 18% for the year ended December 31, 2013, when compared to the same period in 2012. The decrease in revenue was due to lower tonnage put through our all our facilities except Sugar Camp and the sale of one of our processing facilities.

Minimums recognized as revenue decreased $16.5 million or 72% for the year ended December 31, 2013 when compared to the same period in 2012, primarily due to two lessees having significant previously paid minimums losing the ability to recoup them during 2012 that did not occur in 2013.

We recorded a reserve swap for the year ended December 31, 2013 of $8.1 million on our Illinois property. No swap occurred during 2012.

Wheelage revenue decreased by 29% for the year ended December 31, 2013 compared to the same period in 2012. This decrease was due to the normal fluctuations of tonnage that are subject to wheelage charges.

Aggregates and Industrial Minerals Revenues, and Other Related Income

	For the Years Ended December 31, 2013	2012	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
		(Unaudited)		
Aggregates and industrial minerals related revenues	$ 13,479	$ 9,524	$ 3,955	42%
Soda ash revenues and distributions:				
Equity and other unconsolidated investment earnings	$ 34,186	N/A	N/A	N/A
Cash distributions received from OCI Wyoming	$ 72,946	N/A	N/A	N/A

Total aggregates and industrial minerals revenues, and other related income. Total aggregates and industrial minerals revenues, and other related income represented approximately 4% and 3% of our total revenues and other income for the year ended December 31, 2013 and 2012, respectively. The following is a discussion of the major categories of these revenues:

Aggregates and industrial minerals related revenues were up $4.0 million or 42% compared to 2012 due to an increase of $1.2 million in minimums recognized as revenue during 2013. Override revenues also increased on our frac sand properties by $1.6 million during the year ended December 31, 2013. This override was acquired during the fourth quarter of 2012 and did not contribute until 2013.

Equity and other unconsolidated investment earnings. Income from our investment in the OCI Wyoming trona mining and soda ash production business was $34.2 million for the year ended December 31, 2013 and we received $72.9 million in cash distributions which included a special distribution of $44.8 million during the year ended December 31, 2013. We did not own this interest until January 2013.

Oil and Gas Revenues

Oil and gas revenues increased $7.5 million for the year ended December 31, 2013 when compared to the same period in 2012. The increase is primarily due to revenues from our Williston Basin non-operated working interest properties which were acquired during the second half of 2013.

Other Operating Results

Other Revenues. In addition to coal related revenues, aggregates and industrial minerals revenues and oil and gas revenues, we generated approximately 1% of our total revenues and other income from other sources for the years ended December 31, 2014 and 2013 and less than 1% for 2012. Other sources of revenues primarily include: rentals, metal revenue and timber royalties.

Operating expenses. Included in total expenses are:

- Depreciation, depletion and amortization of $79.9 million, $64.4 million and $58.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase in 2014 over 2013 is due to a full year depletion on oil and gas acquisitions acquired in the fourth quarter of 2013 as well as depletion on the Kaiser Francis oil and gas acquisition acquired during the second half of 2014. Also contributing to the increase in depreciation, depletion and amortization is the added expense associated with the acquisition of VantaCore in the fourth quarter of 2014. The increase in 2013 over 2012 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 $36.4 million, $36.8 million and $29.7 million for the years ended December 31, 2014, 2013 and 2012, 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 2014, we recorded additional expenses incurred for the VantaCore and Kaiser Francis acquisitions, these costs were partially offset by lower accruals for our long term incentive plan due to a drop in the unit price. 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 $21.3 million, $16.5 million and $17.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase in property, franchise and other taxes reflects the inclusion of severance tax from our oil and gas properties acquired in late 2013 and 2014. A substantial portion of our property taxes in our coal and aggregates royalty business 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 $80.2 million, $64.4 million and $54.0 million for the years ended December 31, 2014, 2013 and 2012, respectively. Interest increased due to additional debt incurred in 2014 and 2013 to fund acquisitions as well as a refinancing of our credit facility and payment on our term loan with 9.125% high yield notes.

Liquidity and Capital Resources

Liquidity and Financing Activities

As of December 31, 2014, we had $100 million in available borrowing capacity under Opco s revolving credit facility and $27 million of available borrowing capacity under the NRP Oil and Gas revolving credit facility. In addition to the amounts available under our revolving credit facilities, we had $50.1 million in cash at December 31, 2014. Generally, we satisfy our working capital requirements with cash generated from operations. We finance our acquisitions with available cash, borrowings under our revolving credit facilities, and the issuance of debt securities and common units. We typically access the capital markets to refinance amounts outstanding under our revolving credit facilities as we approach the limits under those facilities. Our current liabilities exceeded our current assets by approximately $11.8 million as of December 31, 2014, because we used cash to repay the principal on Opco s notes rather than refinancing the amounts due.

As of December 31, 2014, we were in compliance with all of our debt covenant ratios. Opco s revolving credit facility and term loan facility both mature during 2016. In addition, we are required to make approximately $81 million of principal payments in connection with Opco s senior notes each year through 2018. We also have $425 million principal amount of 9.125% senior notes issued by NRP and NRP Finance, as co-issurers, that mature in 2018. In addition, we will be required to repay or refinance the amounts outstanding under Opco s credit facilities prior to their maturity. While we believe we will be able to refinance these amounts, we may not be able to do so on terms acceptable to us, if at all, or the borrowing capacity under Opco s revolving credit facility may be substantially reduced. Our ability to comply with the financial and other restrictive covenants in our debt agreements will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. In addition, our ability to refinance our debt may depend in part or our ability to access the debt or equity capital markets, which will be challenging in the current market environment. For a more complete discussion of factors that will affect our liquidity, see Item 1A. Risk Factors Risks Related to Our Business.

During 2014, we engaged in several financing transactions in connection with our two major acquisitions. We funded the purchase price of VantaCore through the borrowing of $169.0 million under Opco s revolving credit facility and the issuance of 2,427,503 common units to certain of the sellers. We funded the $339 million purchase price of the Sanish Field acquisition using a combination of the net proceeds of $100.4 million (including our general partner s proportionate capital contribution to maintain its 2% general partner interest in us) from a public offering of 8,500,000 common units at a public offering price of $12.02 per common unit, the net proceeds of $122.6 million from a private offering of an additional $125 million principal amount of our 9.125% Senior Notes due 2018 at an offering price of 99.5%, and borrowings of $117.0 million under the amended NRP Oil and Gas revolving credit facility. Also during 2014, we sold 1,559,914 common units in connection with our at-the-market offering program at an average price of $16.05 per common unit for approximately $25.2 million in net proceeds, including our general partner s proportionate capital contribution in order to maintain its 2% general partner interest in us. We used the net proceeds from these sales for general partnership purposes, including the repayment of principal due on Opco s senior notes.

Capital Expenditures

Our capital expenditures, other than for acquisitions, have historically been minimal. However, as a result of our Sanish Field oil and gas and VantaCore aggregates acquisitions in the fourth quarter of 2014, we anticipate higher operating capital expenditures in 2015. A portion of the capital expenditures associated with both our oil and gas working interest business and VantaCore are maintenance capital expenditures, which are capital expenditures made to maintain the long-term production capacity of those businesses. These maintenance capital expenditures reduce our cash available for distribution to our unitholders. We finance the capital expenditures associated with our Williston Basin non-operated working interest oil and gas assets through a combination of cash flow from operations and borrowings under the NRP Oil and Gas revolving credit facility and are able to control the level of these capital expenditures by evaluating well proposals on a well-by-well basis. We will continue to monitor the development programs of the operators of these properties and manage the capital expenditures associated with those properties by only participating in wells that are expected to provide acceptable economic returns. The capital expenditures in connection with VantaCore s construction aggregates mining and production operations are generally funded through cash flow from operations.

Cash Flows

Net cash provided by operating activities for the years ended December 31, 2014, 2013 and 2012 was $210.8 million, $247.1 million and $271.4 million, respectively. The majority of our cash provided by operations is generated from coal royalty revenues, our equity interest in OCI Wyoming and beginning in 2014, oil and gas revenues.

Net cash used in investing activities for the years ended December 31, 2014, 2013 and 2012 was $520.5 million, $302.8 million and $212.7 million, respectively. Our 2014 investing activities consisted of our Sanish Field oil and gas and VantaCore acquisitions, the $5.0 million Illinois Basin coal acquisition completed in June 2014, as well as additional capital expenditures related to the participation in new wells in connection with our Williston Basin non-operated oil and gas working interest properties. Our 2013 investing activities consisted of the acquisitions of the interest in OCI Wyoming and two acquisitions of 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 Sugar Camp. These uses in 2012 were slightly offset by $24.8 million in proceeds from asset sales.

Net cash flows provided by financing activities for the year ended December 31, 2014 were $267.3 million. Net cash flows used in financing activities for the years ended December 31, 2013 and 2012 were $1.2 million and $124.2 million, respectively. During 2014, 2013 and 2012 we had proceeds from loans of $637.4 million, $567.0 million and $148.0 million, respectively. During 2014, 2013 and 2012, these proceeds were offset by repayment of debt of $328.0 million, $386.2 million and $30.8 million, respectively. Also during 2014, 2013 and 2012 we paid cash distributions to our unitholders of $162.0 million, $246.5 million and $238.0 million, respectively. During 2014, we had net proceeds from an issuance of common units of $122.8 million, together with a capital contribution from our general partner of $3.2 million. During 2013, we had net proceeds from an issuance of common units of $74.7 million, together with a capital contribution from our general partner of $1.5 million.

Table of Contents

Contractual Obligations and Commercial Commitments

NRP Debt

Senior Notes. In September 2013, NRP and NRP Finance, as co-issuers, completed a private offering of $300 million principal amount of 9.125% Senior Notes due 2018 at an offering price of 99.007% of par. 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.

In October 2014, NRP and NRP Finance issued an additional $125 million in aggregate principal amount of the 9.125% Senior Notes due 2018 at an offering price of 99.5% of par. The notes were issued pursuant to the existing indenture and constitute the same series of securities as the existing 9.125% Senior Notes due 2018 issued in September 2013. In the offering, $105 million in aggregate principal amount of the notes were sold in a private offering to the initial purchasers thereof to be offered and sold to qualified institutional buyers pursuant to Rule 144A under the Securities Act, and to persons outside the United States pursuant to Regulation S under the Securities Act. The remaining $20 million in aggregate principal amount of the notes were sold in a separate private offering to Cline Trust Company, LLC.

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

Table of Contents

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:

- $200.0 million under the floating rate revolving credit facility, due August 2016;
- $75.0 million under the floating rate term loan, due January 2016;
- $18.5 million of 4.91% senior notes due 2018;
- $107.1 million of 8.38% senior notes due 2019;
- $46.2 million of 5.05% senior notes due 2020;
- $1.3 million of 5.31% utility local improvement obligation due 2021;
- $24.3 million of 5.55% senior notes due 2023;
- $67.5 million of 4.73% senior notes due 2023;
- $150.0 million of 5.82% senior notes due 2024;
- $45.5 million of 8.92% senior notes due 2024;
- $161.5 million of 5.03% senior notes due 2026; and
- $46.2 million of 5.18% senior notes due 2026.

Senior Notes. Opco issued the senior notes listed above 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. 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 $100 million in available borrowing capacity under its $300 million revolving credit facility, which matures on August 9, 2016.

67

Table of Contents

During 2014, Opco s borrowings and repayments under its revolving credit facility were as follows:

	Quarter Ending			
	March 31	June 30	September 30	December 31
	(In thousands)			
Outstanding balance, beginning of period	$ 20,000	$ 20,000	$ 15,000	$ 7,000
Borrowings under credit facility				394,000
Less: Repayments under credit facility		(5,000)	(8,000)	(201,000)
Outstanding balance, ending period	$ 20,000	$ 15,000	$ 7,000	$ 200,000

Opco s obligations under its revolving credit facility are unsecured but are guaranteed by its subsidiaries. Opco may prepay all amounts outstanding under the 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 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) not less than 3.5 to 1.0.

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.

Term Loan. In connection with the OCI Wyoming soda ash business acquisition in January 2013, Opco entered into a 3-year, $200 million term loan facility. The term loan facility is guaranteed by Opco s operating subsidiaries and bore interest at a weighted average rate of 2.22% in 2014. We repaid $101 million of the term loan during 2013 and an additional $24 million in the fourth quarter of 2014. The remaining balance of $75.0 million is due on January 23, 2016. The term loan facility contains financial covenants and other terms that are identical to those of Opco s revolving credit facility.

NRP Oil and Gas Debt

Revolving Credit Facility. In August 2013, NRP Oil and Gas entered into a senior secured, reserve-based revolving credit facility in order to fund capital expenditure requirements related to the development of the oil and gas assets in which it owns non-operated working interests. In connection with the closing of the Sanish Field acquisition in November 2014, the credit facility was amended to be a $500 million facility with an initial borrowing base of $137 million and will mature on November 12, 2019. 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, 2014, NRP Oil and Gas had $110.0 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 1.50% to 2.50%.

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

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

Long-Term Contractual Obligations

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2014:

	Payments Due by Period (In millions)						
Contractual Obligations	**Total**	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**
NRP:							
Long-term debt principal payments (including current maturities)(1)	$ 425.0	$	$	$	$ 425.0	$	$
Long-term debt interest payments(2)	155.2	38.8	38.8	38.8	38.8		
NRP Oil and Gas:							
Long-term debt principal payments	110.0					110.0	
Opco:							
Long-term debt principal payments (including current maturities)(3)	943.1	81.0	356.0	81.0	81.0	76.4	267.7
Long-term debt interest payments(4)	187.0	38.4	33.3	28.2	23.2	18.2	45.7
Rental leases(5)	2.7	0.7	0.7	0.7	0.6		
Total	$ 1,823.0	$ 158.9	$ 428.8	$ 148.7	$ 568.6	$ 204.6	$ 313.4

(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. On October 17, 2014 NRP and NRP Finance issued an additional $125 million of 9.125% senior notes at an offering price of 99.5% of par value.

(2) The amounts indicated in the table include interest due on NRP s 9.125% senior notes.

Table of Contents

(3) The amounts indicated in the table include principal due on Opco s senior notes, credit facility, term loan and utility local improvement obligation.

(4) The amounts indicated in the table include interest due on Opco s senior notes and utility local improvement obligation.

(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 through 2017. These rental obligations are included in the table above.

Shelf Registration Statements and At-the-Market Program

In April 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. In October 2014, we issued 8,500,000 common units in an underwritten public offering pursuant to this registration statement at a public offering price of $12.02 per common unit. We used the net proceeds of approximately $100.4 million from this offering, including our general partner s proportionate capital contribution to maintain its 2% general partner interest in us, to fund a portion of the purchase price of the Sanish Field acquisition.

In August 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 in September 2012. Following the effectiveness of this registration statement, Adena distributed 15,181,716 common units to its shareholders, and we subsequently filed prospectus supplements to register the resale of these common units by those shareholders. The shelf registration statement filed in August 2012 also registered up to $500 million in equity securities to be sold by NRP. In November 2013, we filed a prospectus supplement and entered into an Equity Distribution Agreement relating to the offer and sale from time to time of common units having an aggregate offering price of $75 million through one or more managers acting as sales agents at prices to be agreed upon at the time of sale. Under the terms of the Equity Distribution Agreement, we may also sell common units from time to time to any manager as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to any manager as principal would be pursuant to the terms of a separate terms agreement between NRP and such manager. Sales of common units in this at-the-market (ATM) program are made pursuant to the shelf registration statement declared effective in September 2012. For the year ended December 31, 2014, we sold 1,559,914 common units for an average price of $16.05 for gross proceeds of $25.0 million.

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

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

Off-Balance Sheet Transactions

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

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, 2014, 2013 and 2012.

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. We make regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. We believe that our lessees will be able to comply with existing regulations and do not expect any lessee s failure to comply with environmental laws and regulations to have a material impact on our financial condition or results of operations. We have neither incurred, nor are aware of, any material environmental charges imposed on us related to our properties for the period ended December 31, 2014. We are not associated with any environmental contamination that may require remediation costs. However, our lessees do conduct reclamation work on the properties under lease to them. Because we are not the permittee of the mines being reclaimed, we are not responsible for the costs associated with these reclamation operations. In addition, West Virginia has established a fund to satisfy any shortfall in reclamation obligations. 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. We are also responsible for losses and liabilities, including environmental liabilities that may arise from uninsured and underinsured events.

For additional information on environmental regulation that may have a material impact on our business, see Executive Overview Political, Legal and Regulatory Environment Affecting Our Coal Business and Item 1. Business Regulation and Environmental Matters.

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,		
	2014	2013	2012
	(In thousands)		
Reimbursement for services	$ 11,798	$ 11,480	$ 9,791

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 LP, 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

Table of Contents

filing. At December 31, 2014, we had accounts receivable totaling $9.2 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 $50.0 million on our Consolidated Balance Sheets. Revenues from the Cline affiliates are as follows:

	For The Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Coal royalty revenues	$ 52,415	$ 54,322	$ 48,567
Processing and transportation fees	20,594	19,258	21,923
Minimums recognized as revenue		3,477	17,785
Override revenue	2,847	3,226	4,066
Other revenue	5,690	8,149	
	$ 81,546	$ 88,432	$ 92,341

As of December 31, 2014, we had received $86.8 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $16.0 million was received in 2014.

During the fourth quarter of 2012, we recognized an impairment of $2.6 million related to the assets at the Gatling West Virginia location, a location leased to and affiliate of Chris Cline.

During 2014 and 2013, we recognized non-cash gains of $5.7 million and $8.1 million on reserve exchanges in Illinois with Williamson Energy, a subsidiary of Foresight Energy LP. The tons received during 2014 and 2013 were fully mined during each of those years, while the tons exchanged are not included in current mine plans. The gains are included in Coal related revenues on the Consolidated Statement of Comprehensive Income.

We entered into a lease agreement related to the rail loadout and associated facilities at Sugar Camp that has been accounted for as a direct financing lease. Total projected remaining payments under the lease at December 31, 2014 are $86.3 million with unearned income of $39.0 million. The net amount receivable under the lease as of December 31, 2014 was $47.3 million, of which $1.8 million is included in Accounts receivable affiliates while the remaining is included in Long-term contracts receivable affiliate on the accompanying Consolidated Balance Sheets.

In a separate transaction, we acquired a contractual overriding royalty interest from a Cline affiliate that provides for payments based upon production from specific tons at the Sugar Camp operations. This overriding royalty was accounted for as a financing arrangement and is reflected as an affiliate receivable. The net amount receivable under the agreement as of December 31, 2014 was $5.6 million, of which $1.1 million is included in Accounts receivable affiliates while the remaining is included in Long-term contracts receivable affiliate on the accompanying Consolidated Balance Sheets.

Note to Cline Trust Company, LLC

Donald R. Holcomb, one of our directors, is a manager of Cline Trust Company, LLC, which owns approximately 5.35 million of our common units and $20 million in principal amount of our 9.125% Senior Notes due 2018. The members of the Cline Trust Company are four trusts for the benefit of the children of Christopher Cline, each of which owns an approximately equal membership interest in the Cline Trust Company. Mr. Holcomb also serves as trustee of each of the four trusts. Cline Trust Company, LLC purchased the $20 million of our 9.125% Senior Notes due 2018 in our offering of $125 million additional principal amount of such notes in October 2014 at the same price as the other purchasers in that offering. The balance on this portion of our 9.125% Senior Notes due 2018 was $19.9 million as of December 31, 2014 and is included with our long term debt.

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. In 2013, Taggart was sold to Forge Group, and Quintana no longer retains an interest in Taggart or Forge. We own and lease preparation plants to Forge, which operates the plants. The lease payments were based on the sales price for the coal that was processed through the facilities.

For the years ended December 31, 2014, 2013 and 2012, the revenues from Taggart prior to the sale to Forge were as follows:

	For the Years Ended December 31,		
	2014	2013	2012
		(In thousands)	
Processing revenue	$	$ 1,761	$ 5,580

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 or the Consolidated Statements of Income for 2012. The net book value of the asset sold was $7.6 million. During 2013, 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,		
	2014	2013	2012
		(In thousands)	
Coal royalty revenues	$ 3,013	$ 4,594	$ 3,486

NRP also had accounts receivable totaling $0.3 million from Corsa at each of December 31, 2013 and December 31, 2014.

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

Table of Contents

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 the Opco revolving credit facility, the Opco term loan and the NRP Oil and Gas revolving 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, 2014, we had $385 million outstanding in variable interest debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $3.9 million, assuming the same principal amount remained outstanding during the year.

Table of Contents

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

INDEX TO CONSOLIDATED 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, 2014 and 2013, 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, 2014. 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 LLC (OCI Wyoming) (a Limited Liability Company in which Natural Resource Partners L.P. owns a 49% interest). Natural Resource Partners L.P. s investment in OCI Wyoming constituted approximately $264 million and $269 million of Natural Resource Partners L.P. s assets as of December 31, 2014 and 2013, and total revenues of $41 million and $34 million for the two years in the period ended December 31, 2014. Those statements were audited by other auditors whose report has been furnished to us. Our opinion, insofar as it relates to the amounts included for Natural Resource Partners L.P., 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 provides 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. and subsidiaries at December 31, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 27, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 27, 2015

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Managers and Members of

OCI Wyoming LLC

Atlanta, Georgia

We have audited the accompanying balance sheets of OCI Wyoming LLC (the Company) as of December 31, 2014 and 2013, and the related statements of operations and comprehensive income, members equity, and cash flows for the years then ended, and the related notes to the financial statements. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia

February 26, 2015

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands, except for unit information)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 50,076	$ 92,513
Accounts receivable, net of allowance for doubtful accounts	66,455	33,737
Accounts receivable affiliates	9,494	7,666
Inventory	5,814	
Other	4,279	1,691
Total current assets	136,118	135,607
Land	25,243	24,340
Plant and equipment, net	60,093	26,435
Mineral rights, net	1,781,852	1,405,455
Intangible assets, net	60,733	66,950
Equity and other unconsolidated investments	264,020	269,338
Loan financing costs, net	13,905	11,502
Long-term contracts receivable affiliates	50,008	51,732
Goodwill	52,012	
Other assets	740	497
Total assets	$ 2,444,724	$ 1,991,856
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 32,416	$ 8,659
Accounts payable affiliates	950	391
Current portion of long-term debt	80,983	80,983
Accrued incentive plan expenses current portion	7,048	8,341
Property, franchise and other taxes payable	8,318	7,830
Accrued interest	18,216	17,184
Total current liabilities	147,931	123,388
Deferred revenue	160,260	142,586
Accrued incentive plan expenses	6,554	10,526
Asset retirement obligation	4,905	
Other non-current liabilities	10,679	14,341
Long-term debt	1,394,240	1,084,226
Partners capital:		
Common units outstanding: (122,299,825 and 109,812,408)	709,019	606,774
General partner s interest	12,245	10,069
Non-controlling interest	(650)	324
Accumulated other comprehensive loss	(459)	(378)
Total partners capital	720,155	616,789
Total liabilities and partners capital	$ 2,444,724	$ 1,991,856

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

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In thousands, except per unit data)

	For the Years Ended December 31, 2014	2013	2012
Revenues and other income:			
Coal related revenues	$ 226,724	$ 274,194	$ 343,352
Aggregates related revenues	54,124	13,479	9,524
Oil and gas related revenues	59,566	17,080	9,561
Equity and other unconsolidated investment income	41,416	34,186	
Property taxes	13,609	15,416	15,273
Other	4,313	3,762	1,437
Total revenues and other income	399,752	358,117	379,147
Operating expenses:			
Depreciation, depletion and amortization	79,876	64,377	58,221
Asset impairments	26,209	734	2,568
General and administrative	36,437	36,821	29,714
Property, franchise and other taxes	21,279	16,463	17,678
Oil and gas lease operating expenses	9,144	739	
Aggregates operating expenses	32,309		
Transportation costs	1,604	1,644	1,944
Coal royalty and override payments	3,975	1,103	1,857
Total operating expenses	210,833	121,881	111,982
Income from operations	188,919	236,236	267,165
Other income (expense)			
Interest expense	(80,185)	(64,396)	(53,972)
Interest income	96	238	162
Income before non-controlling interest	108,830	172,078	213,355
Non-controlling interest			
Net income	$ 108,830	$ 172,078	$ 213,355
Net income attributable to:			
General partner	$ 2,177	$ 3,442	$ 4,267
Limited partners	$ 106,653	$ 168,636	$ 209,088
Basic and diluted net income per limited partner unit	$ 0.94	$ 1.54	$ 1.97
Weighted average number of common units outstanding	113,262	109,584	106,028
Comprehensive income	$ 108,749	$ 172,143	$ 213,405

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(In thousands, except unit data)

	Common Units		General Partner	Non-Controlling Interest	Accumulated Other Comprehensive Income (Loss)	
	Units	Amounts	Amounts	Amounts		Total
Balance at December 31, 2011	106,027,836	$ 629,253	$ 10,517	$ 5,638	$ (493)	$ 644,915
Distributions to unitholders		(233,263)	(4,758)			(238,021)
Distributions to non-controlling interests				(2,793)		(2,793)
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 to unitholders		(241,588)	(4,930)			(246,518)
Distributions to non-controlling interests				(2,521)		(2,521)
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
Issuance of common units	10,059,914	127,202				127,202
Issuance of common units for acquisitions	2,427,503	31,604				31,604
Capital contribution			3,240			3,240
Cost associated with equity transactions		(4,413)				(4,413)
Distributions to unitholders		(158,801)	(3,241)			(162,042)
Distributions to non-controlling interests				(974)		(974)
Net income for the year ended December 31, 2014		106,653	2,177			108,830
Interest rate swap from unconsolidated investments					(96)	(96)
Unrealized loss on investments					(25)	(25)
Loss on interest hedge					40	40
Comprehensive income					(81)	108,749

Balance at December 31, 2014	122,299,825	$ 709,019	$ 12,245	$ (650)	$ (459)	$ 720,155

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

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	For the Years Ended December 31, 2014	2013	2012
Cash flows from operating activities:			
Net income	$ 108,830	$ 172,078	$ 213,355
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	79,876	64,377	58,221
Non-cash interest charge	3,328	2,200	605
Non-cash gain on reserve swap	(5,690)	(8,149)	
Equity and other unconsolidated investment income	(41,416)	(34,186)	
Distributions of earnings from unconsolidated investments	43,005	24,113	
Gain on sale of assets	(1,386)	(10,921)	(13,575)
Asset impairment	26,209	734	2,568
Change in operating assets and liabilities (net of effects of acquisitions):			
Inventory	748		
Accounts receivable	(10,693)	6,826	(802)
Other assets	(795)	(516)	(236)
Accounts payable and accrued liabilities	(4,411)	2,197	1,909
Accrued interest	1,032	6,919	(496)
Deferred revenue	17,674	19,240	11,684
Accrued incentive plan expenses	(5,265)	2,284	(3,461)
Property, franchise and other taxes payable	(291)	(122)	1,636
Net cash provided by operating activities	210,755	247,074	271,408
Cash flows from investing activities:			
Acquisition of land, coal, other mineral rights and related intangibles	(339,768)	(72,000)	(180,534)
Acquisition of equity interests		(293,085)	
Acquisition of aggregates business	(168,978)		
Oil and gas capital expenditures	(16,258)		
Distributions from unconsolidated investments	3,633	48,833	
Acquisition of plant and equipment	(2,454)		(681)
Proceeds from sale of assets	1,418	10,929	24,822
Return on direct financing lease and contractual override	1,904	2,558	2,669
Investment in direct financing lease			(59,009)
Net cash used in investing activities	(520,503)	(302,765)	(212,733)
Cash flows from financing activities:			
Proceeds from loans	637,375	567,020	148,000
Proceeds from issuance of common units	127,202	75,000	
Deferred financing costs	(5,094)	(9,209)	
Repayments of loans	(327,983)	(386,230)	(30,800)
Payment of obligation related to acquisitions			(500)
Costs associated with equity transactions	(4,413)	(293)	(59)
Distributions to unitholders	(162,042)	(246,518)	(238,021)
Distributions to non-controlling interests	(974)	(2,521)	(2,793)
Capital contribution by general partner	3,240	1,531	
Net cash provided by (used in) financing activities	267,311	(1,220)	(124,173)
Net (decrease) in cash and cash equivalents	(42,437)	(56,911)	(65,498)
Cash and cash equivalents at beginning of period	92,513	149,424	214,922

Cash and cash equivalents at end of period	$ 50,076	$ 92,513	$ 149,424
Supplemental cash flow information:			
Cash paid during the period for interest	$ 76,155	$ 55,191	$ 53,842
Non-cash investing activities:			
Units issued for acquisition of aggregate operations	$ 31,604		
Note receivable related to sale of assets			$ 1,808
Non-cash contingent consideration on equity investments		$ 15,000	

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

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Organization

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, managing and leasing a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, oil and gas, construction aggregates, frac sand and other natural resources.

The Partnership s coal reserves are located in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. The Partnership does not operate any coal mines, but leases its coal reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell its reserves in exchange for royalty payments. The Partnership also owns and manages infrastructure assets that generate additional revenues, primarily in the Illinois Basin.

The Partnership owns or leases aggregates and industrial minerals located in a number of states across the country. The Partnership derives a small percentage of its aggregates and industrial mineral revenues by leasing its owned reserves to third party operators who mine and sell the reserves in exchange for royalty payments. However, the majority of the Partnership s aggregates revenues come through its ownership of VantaCore Partners LLC, which was acquired in October 2014. VantaCore specializes in the construction materials industry and operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal. VantaCore s current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

The Partnership also owns a 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. OCI Resources LP, the Partnership s operating partner, mines the trona, processes it into soda ash, and distributes the soda ash both domestically and internationally into the glass and chemicals industries. The Partnership receives regular quarterly distributions from this business, and records the income in accordance with the equity method of accounting.

The Partnership also owns various interests in oil and gas properties that are located in the Williston Basin, the Appalachian Basin, Louisiana and Oklahoma. The Partnership s interests in the Appalachian Basin, Louisiana and Oklahoma are minerals and royalty interests, while in the Williston Basin the Partnership owns non-operated working interests.

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

Reclassification

Certain reclassifications have been made to the Consolidated Statements of Comprehensive Income. Amounts relating to prior year s coal royalties, processing fees, transportation fees, minimums recognized as revenue, override royalties and other have been reclassified into a single line item Coal related revenues on this year s Consolidated Statements of Comprehensive Income. Amounts relating to prior year s aggregates royalties, processing fees, minimums recognized as revenue, override royalties and other have been reclassified into a single line item Aggregates related revenues on this year s Consolidated Statements of Comprehensive Income. Amounts relating to prior year s oil and gas revenues and minimums recognized as revenue have been reclassified into a single line item Oil and gas related revenues on this year s Consolidated Statements of Comprehensive Income. The following is reclassification reconciliation:

	For The Year Ended December 31, 2013			For The Year Ended December 31, 2012			
	As Reported	As Reclassified		As Reported	As Reclassified		
	Total	Coal Related Revenues	Aggregates Related Revenues	Total	Coal Related Revenues	Aggregates Related Revenues	Oil & Gas Related Revenues
Revenues:							
Coal royalties	$ 212,663	$ 212,663	$	$ 260,734	$ 260,734	$	$
Equity and other unconsolidated investment income	34,186						
Aggregate royalties	7,643		7,643	6,598		6,598	
Processing fees	5,049	4,542	507	8,299	7,841	458	
Transportation fees	17,977	17,977		19,513	19,513		
Oil and gas royalties	17,080			9,160			9,160
Property taxes	15,416			15,273			
Minimums recognized as revenue	8,285	6,528	1,757	23,956	23,029	526	401
Override royalties	13,499	10,372	3,127	15,527	13,979	1,548	
Other	26,319	22,112	445	20,087	18,256	394	
Total revenues	$ 358,117	$ 274,194	$ 13,479	$ 379,147	$ 343,352	$ 9,524	$ 9,561

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 joint venture with International Paper Company controlled by the Partnership. Intercompany transactions and balances have been eliminated.

Business Combinations

For purchase acquisitions accounted for as business combinations, 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.

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 and Cash Equivalents

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 and customers 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 accounts receivable and when it becomes aware of a specific lessee s or 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 or customer 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.

Inventory

Inventories are stated at the lower of cost or market. The cost of aggregates and asphalt components such as stone, sand, and recycled and liquid asphalt is determined by the first-in, first-out (FIFO) method. Cost includes all direct materials, direct labor and related production overheads based on normal operating capacity. The cost of supplies inventory is determined by the average cost method and includes operating and maintenance supplies to be used in the Partnership s aggregates operations.

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 generally as follows:

	Years
Buildings and improvements	20 to 40
Machinery and equipment	5 to 12

Leasehold improvements	Life of Lease

Table of Contents

The Partnership begins capitalizing mine development costs at its aggregates operations at a point when reserves are determined to be proven or probable, economically mineable and when demand supports investment in the market. Capitalization of these costs ceases when production commences. Mine development costs are amortized based on production over the estimated life of mineral reserves and amortization is included as a component of depreciation expense.

Mineral Rights

Mineral rights owned and leased are initially recorded using the FASB s business combination and asset purchase authoritative guidance depending on circumstances. 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. 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 asset, whichever is shorter.

Intangible Assets

The Partnership s intangible assets consist primarily of contracts that at acquisition were more favorable for the Partnership than prevailing market rates, known as above-market contracts. The estimated fair values 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.

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 investments 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, then to 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 its estimated useful life while indefinite-lived intangibles, if any, and goodwill are 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.

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 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.

Table of Contents

Deferred Financing Costs

Deferred financing costs consist of legal and other costs related to the issuance of the Partnership s long-term debt. These costs are amortized over the term of the debt.

Asset Impairment

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. A long-lived asset is deemed impaired when the future expected undiscounted cash flows from its use and disposition is less than the assets carrying value. Impairment is measured based on the estimated fair value, which is usually determined based upon the present value of the projected future cash flow compared to the assets carrying value. 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 and the potential for further declines in oil and natural gas prices, the Partnership intends to closely monitor its coal and oil and gas assets 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.

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 for equity investments as of December 31, 2014.

In accordance with accounting and disclosure guidance for goodwill, the Partnership tests its recorded goodwill for impairment annually or more often if indicators of potential impairment exist, by determining if the carrying value of a reporting unit exceeds its estimated fair value. Factors that could trigger an interim impairment test include, but are not limited to, underperformance relative to historical or projected future operating results or significant changes in the reporting units, business, industry, or economic trends.

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. See Note 16. Incentive Plans.

Deferred Revenue

Most of the Partnership s coal and aggregates 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 revenue based upon the underlying mineral lease when the lessee recoups the minimum payment through production or in the period immediately following the expiration of the lessee s ability to recoup the payments.

Table of Contents

Asset Retirement Costs and Obligations

The Partnership accrues for mine closure, reclamation as well as plugging and abandonment of its oil and gas non-operated working interests in accordance with authoritative guidance related to accounting for asset retirement and environmental obligations. This guidance requires the fair value of an obligation be recognized in the period it is incurred, if the fair value can be reasonably estimated. The Partnership recognizes an asset and liability related to the present value of future estimated costs. Depreciation or depletion of the capitalized asset retirement cost is determined based upon the underlying asset being retired in the future. Accretion of the asset retirement obligation is recognized over time and will increase as the obligation becomes more near term. It is reasonably possible that the estimates related to asset retirement and environmental obligations may change in the future. See Note 13. Asset Retirement Obligations.

Revenues

Coal related revenues. Coal related revenue consist primarily of royalties as well as transportation and processing fees. 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 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 related revenues consist of non-operated working interests, royalties and overriding royalties. Revenues related to the Partnership s non-operated working interests in oil and gas assets are recognized based on the amount actually sold. 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 the wells, including the cost of development and production. Oil and gas royalty revenues are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. 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.

Aggregates and Industrial Minerals Related Revenues. Aggregates and industrial minerals related revenues consist primarily of revenues generated by VantaCore s construction aggregates business, royalties and overriding royalties. Revenues from the sale of aggregates, gravel, sand and asphalt are recorded based upon the transfer of product at delivery to customers, which generally occurs at the quarries or asphalt plants at either market or contractual prices. Aggregates royalty and overriding 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. Revenues from long-term construction contracts are recognized on the percentage-of-completion method, measured by the percentage of total costs incurred to date to the estimated total costs for each contract. That method is used since the Partnership considers total cost to be the best available measure of progress on the contracts. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are determined. Changes in job performance, job conditions and estimated profitability, including those arising from final contract settlements, which result in revisions to job costs and profits are recognized in the period in which the revisions are determined. Contract costs include all direct job costs and those indirect costs related to contract performance, such as indirect labor, supplies, insurance, equipment maintenance and depreciation. General and administrative costs are charged to expense as incurred.

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 payment of and reimbursement of property taxes is included in Property taxes revenue and in Property, franchise and other taxes expense, respectively, in the Consolidated Statements of Comprehensive Income.

Transportation Revenue and Expense

Shipping and handling costs invoiced to aggregate customers and paid to third-party carriers are recorded as Aggregate related revenues and Aggregates operating expenses 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.

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.

New Accounting Standards

In May 2014, the FASB amended revenue recognition topics and created a new topic relating to revenue recognition that will supersede existing guidance under U.S. GAAP. The core principle of the new guidance is to recognize revenue when promised goods or services are transferred to the customer and in an amount that reflects the consideration expected in exchange for those goods or services. To achieve this core principle, an entity should (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract and (5) recognize revenue when each performance obligation is satisfied**.** The guidance also specifies the accounting for some costs to obtain or fulfill a contract with a customer. Disclosure requirements include sufficient qualitative and quantitative information to enable financial statement users to understand the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The new topic is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The guidance allows for either full adoption or a modified retrospective adoption. The Partnership is currently evaluating the requirements to determine the impact, if any, of this new topic on its financial position, results of operations and cash flows.

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.

Table of Contents

3. Significant Acquisitions

VantaCore. Consistent with the Partnership s diversification plan, on October 1, 2014, the Partnership completed its acquisition of VantaCore Partners LLC (VantaCore), a privately held company specializing in the construction materials industry, for $201 million in cash and common units. Headquartered in Philadelphia, Pennsylvania, VantaCore operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal. VantaCore s current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

Transaction costs through December 31, 2014 associated with this acquisition were $2.9 million and were expensed as incurred. These expenses are reflected in General and administrative expense on the Consolidated Statements of Comprehensive Income. Included in the consolidated statements of comprehensive income for the year ended December 31, 2014 were revenue of $42.1 million and operating expenses of $32.3 million, including depreciation and depletion of $3.2 million.

The Partnership accounted for the transaction in accordance with the authoritative guidance for business combinations, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of October 1, 2014. The following table summarizes the purchase price and the preliminary estimated values of assets acquired and liabilities assumed and are subject to revision as the Partnership continues to complete appraisals of the fair value of the assets acquired and liabilities assumed. The preliminary allocation was based on the book values of the assets and liabilities assumed with the excess of purchase price over net book value allocated to goodwill. Adjustments to the estimated fair values may be recorded during the allocation period, not to exceed one year from the date of acquisition.

Preliminary Purchase Price Allocation VantaCore Partners LLC Acquisition

	October 1, 2014 (In thousands)
Consideration	
Cash	$ 168,978
NRP common units(1)	31,604
Total consideration given	$ 200,582
Preliminary Allocation of Purchase Price	
Current assets	$ 37,222
Land, property and equipment	40,411
Mineral rights	87,907
Other assets	3,268
Current liabilities	(16,953)
Asset retirement obligation	(3,285)
Goodwill	52,012
Fair value of net assets acquired	$ 200,582

(1) Includes 2,426,690 units issued on October 1, 2014 at $13.02, closing price on that day and 813 units issued for a post-closing adjustment on December 4, 2014 at $10.48.

Sanish Field. Consistent with the Partnership s diversification plans, in November 2014, the Partnership completed the purchase of a 40% member interest in Kaiser-Whiting, LLC (Kaiser LLC) for $339 million, subject to customary post-closing purchase price adjustments. Effective November 13, 2014, NRP Oil and Gas withdrew as a member of Kaiser LLC and an undivided 40% interest in Kaiser LLC s assets was distributed out of Kaiser LLC, and assigned directly to the Partnership. The assets distributed to the Partnership included non-operated working interests in approximately 6,086 net acres with an average working interest of approximately 14.5%. The assets, located in the Sanish Field in Mountrail County, North Dakota, are all held by production and include 192 producing wells.

Table of Contents

The transaction costs incurred in connection with this acquisition were $1.8 million through December 31, 2014, and were expensed as incurred. These expenses are reflected in General and administrative expense on the Consolidated Statements of Comprehensive Income. Included in the consolidated statements of comprehensive income for the year ended December 31, 2014, was revenue of $12.8 million and operating costs of $9.1 million including depletion expense of $6.7 million related to the Sanish Field acquisition.

The Partnership accounted for the transaction in accordance with the authoritative guidance for business combinations, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of November 12, 2014. The following table summarizes the preliminary purchase price and the preliminary estimated values of assets acquired and liabilities assumed and are subject to revision as the Partnership continues to complete appraisals of the fair value of the assets and liabilities assumed. Adjustments to the estimated fair values may be recorded during the allocation period, not to exceed one year from the date of acquisition.

Preliminary Purchase Price Allocation Sanish Field Acquisition

		November 12, 2014 (In thousands)
Mineral rights		
Proven oil and gas properties	$	298,627
Probable and possible resources		40,800
Total fair value of oil and gas properties acquired		339,427
Asset retirement obligation		(427)
Fair value of net assets acquired	$	339,000

Pending the final purchase price adjustments and allocation, the net assets acquired of approximately $339.4 million are included in Mineral Rights in the accompanying Consolidated Balance Sheet. The acquisition qualifies as a business combination, and as such, the Partnership estimated the fair value of each asset acquired and liability assumed as of the acquisition date. Fair value measurements utilize assumptions of market participants. To determine the fair value of the oil and gas assets, the Partnership used an income approach based on a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk-adjusted discount rates. The Partnership determined the appropriate discount rates used for the discounted cash flow analyses by using a weighted average cost of capital from a market participant perspective plus reserve-specific risk premiums for the assets acquired. The Partnership estimated reserve-specific risk premiums taking into consideration that the related reserves are primarily oil, among other hydrocarbons. Given the unobservable nature of some of the significant inputs, they are deemed to be Level 3 in the fair value hierarchy. The initial estimate of asset retirement obligation liability was based upon historical information from Kaiser LLC.

Pro Forma Financial Information

As stated above, the Partnership completed the Sanish Field acquisition on November 13, 2014 and the VantaCore acquisition on October 1, 2014. Below are the combined results of operations for the twelve months ended December 31, 2014 and 2013 as if the acquisitions had occurred on January 1, 2013.

The unaudited pro forma results reflect significant pro forma adjustments related to funding the acquisition through the issuance of Partnership units and debt and additional depletion expense as a result of the Kaiser and VantaCore acquisitions. The pro forma results do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Partnership to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the period, nor are they necessarily indicative of future results.

	For the Years ended December 31, 2014	2013
	(In thousands)	
Revenue and other income except aggregate and oil and gas related revenues	$ 286,062	$ 327,558
Aggregates related revenues	137,220	152,032
Oil and gas related revenues	110,235	100,343
Total revenue	$ 533,517	$ 579,933
Net income	$ 122,319	$ 197,164
Basic and diluted net income per limited partner unit	$ 0.99	$ 1.60

Sundance. On December 19, 2013, the Partnership completed the acquisition of non-operated working interests in oil and gas properties in the Williston Basin of North Dakota from Sundance Energy, Inc. for $29.4 million, following post-closing purchase price adjustments. The Partnership accounted for the transaction in accordance with the authoritative guidance for business combinations. During the third quarter of 2014, the Partnership finalized the determination of the fair value of the assets acquired and liabilities assumed in the acquisition, with no material adjustments. The assets acquired are included in Mineral rights in the accompanying Consolidated Balance Sheets.

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

With respect to the Abraxas and Sundance acquisitions, revenues of $36.1 million, capital expenditures of $22.9 and operating expenses of $12.3 million were included in the Consolidated Statements of Comprehensive Income and Consolidated Balance Sheet for the year ended December 31, 2014. For the year ended December 31, 2013, revenues and total operating expenses from the Abraxas and Sundance acquisitions were $5.4 million and $2.9 million, respectively.

4. Equity and Other Investments

The Partnership owns a 49% non-controlling equity interest in OCI Wyoming LLC (OCI Wyoming). The investment was acquired from Anadarko Holding Company (Anadarko) and its subsidiary, Big Island Trona Company for $292.5 million during 2013. OCI Wyoming s operations consist of the mining of trona ore, which, when refined, become soda ash. All soda ash is sold through an affiliated sales agent to various domestic and European customers and to American Natural Soda Ash Corporation for export primarily to Asia and Latin America. Included in fair value adjustments, is an increase in the Partnership s proportionate fair value of property, plant and equipment of $65.4 million, which will be depreciated using the straight-line method over a weighted average life of 28 years. Also, $132.7 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 amounts 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 investment.

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 as defined in the purchase and sale agreement be met by OCI Wyoming in any of the years 2013, 2014 or 2015. At December 31, 2014, the Partnership had accrued $14.5 million of contingent consideration that is included in Equity and other

Table of Contents

unconsolidated investments. The current portion of $3.8 million is included in Accounts payable and accrued liabilities and the long term portion of $10.7 million is included in Other non-current liabilities. During 2014 the Partnership paid a $0.5 million payment for contingent consideration.

The table below summarizes the differences between the carrying amount of the Partnership s investment and the amount of the Partnership s underlying equity in the net assets of OCI Wyoming. For both the twelve month periods ended December 31, 2014 and 2013, the Partnership derived approximately 10% of its revenues and other income from its equity investment in OCI Wyoming.

	For the Year Ended December 31,	
	2014	2013
	(In thousands)	
Net book value of NRP s equity interests	$ 101,311	$ 96,692
Equity and other unconsolidated investments	$ 264,020	$ 269,338
Excess of NRP s investment over net book value of NRP s equity interest	$ 162,709	$ 172,646
Income allocation to NRP s equity interests	$ 47,354	$ 37,036
Amortization of basis difference	$ (5,938)	$ (2850)
Equity and other unconsolidated investment income	$ 41,416	$ 34,186

The following summarized financial information was taken from the OCI Wyoming-prepared financial statements.

	For the Year Ended December 31,	
	2014	2013
	(In thousands)	
Sales	$ 465,032	$ 442,132
Gross profit	$ 118,439	$ 94,299
Net Income	$ 96,640	$ 79,655
Current assets	$ 200,622	$ 201,265
Noncurrent assets	$ 202,282	$ 194,508
Current liabilities	$ 47,704	$ 39,663
Noncurrent liabilities	$ 149,192	$ 158,779

5. Allowance for Doubtful Accounts

Activity in the allowance for doubtful accounts for the years ended December 31, 2014, 2013 and 2012 was as follows:

	2014	2013	2012
		(In thousands)	
Balance, January 1	$ 275	$ 711	$ 393
Provision charged to operations:			
Additions to the reserve	774	278	318
Collections of previously reserved accounts	(373)		
Total charged (credited) to operations	401	278	318
Non-recoverable balances written off		(714)	
Balance, December 31	$ 676	$ 275	$ 711

Table of Contents

The Partnership acquired $0.5 million of allowances for doubtful accounts with its acquisition of VantaCore.

6. Inventory

The components of inventories at December 31, 2014 are as follows:

	2014 (In thousands)
Aggregates	$ 4,596
Supplies and parts	1,218
	$ 5,814

All of the Partnership s inventory for 2014 was acquired with its acquisition of VantaCore. For the year ended December 31, 2013, the Partnership did not have inventory.

7. Plant and Equipment

The Partnership s plant and equipment consist of the following:

	December 31, 2014	December 31, 2013
	(In thousands)	
Construction in process	$ 457	$
Plant and equipment at cost	89,759	55,271
Less accumulated depreciation	(30,123)	(28,836)
Net book value	$ 60,093	$ 26,435

	For the Years ended December 31,		
	2014	2013	2012
		(In thousands)	
Total depreciation expense on plant and equipment	$ 7,631	$ 5,966	$ 6,825

During the fourth quarter of 2014, the Partnership impaired a preparation plant. The impairment charge was $0.8 million and is included in Asset impairments in the Consolidated Statements of Comprehensive Income for the year ending December 31, 2014.

8. Mineral Rights

The Partnership s mineral rights consist of the following:

	December 31, 2014	December 31, 2013
	(In thousands)	
Coal	$ 1,541,572	$ 1,574,914

Oil and gas	560,395	204,906
Aggregates	211,490	100,080
Other	15,014	15,020
Less accumulated depletion and amortization	(546,619)	(489,465)
Net book value	$ 1,781,852	$ 1,405,455

Table of Contents

	2014	For the years ended December 31, 2013 (In thousands)	2012
Total depletion and amortization expense on mineral interests	$ 68,603	$ 54,595	$ 47,042

During its annual impairment analysis, the Partnership concluded certain unleased properties were impaired due primarily to the ongoing regulatory environment and continued depressed coal markets with little indications of improvement in the near term. While these conditions affect the Partnership s ability to lease properties, other events such as a lessee s bankruptcy, a lease cancellation, lease modifications, a permanent idling of a property could result in triggering events warranting further analysis. The fair values for those unleased properties were determined for the associated reserves using Level 2 market approaches based upon recent comparable sales and Level 3 expected cash flows. The resulting impairment expense of $19.8 million relating to coal and aggregates mineral properties is included in Asset impairments on the Consolidated Statements of Comprehensive Income.

9. Intangible Assets

Amounts recorded as intangible assets along with the balances and accumulated amortization at December 31, 2014 and 2013 are reflected in the table below:

	December 31, 2014	December 31, 2013
	(In thousands)	
Contract intangibles	$ 82,972	$ 89,421
Other intangibles	3,004	
Less accumulated amortization	(25,243)	(22,471)
Net book value	$ 60,733	$ 66,950

	2014	For the Years Ended December 31, 2013 (In thousands)	2012
Total amortization expense on intangible assets	$ 3,642	$ 3,816	$ 4,354

Included in intangible assets are certain contract intangibles with a net book value of $1.3 million at December 31, 2014 that were deemed held for sale. During the fourth quarter $52.0 million of goodwill was added relating to the VantaCore acquisition. This amount represents the preliminary residual value and will be adjusted as the Partnership continues complete appraisals of fair value relating to the acquisition.

During the second quarter of 2014, the Partnership and a lessee amended an aggregates lease, which led the Partnership to conclude an impairment triggering event had occurred. Fair value of the lease agreement was determined using Level 3 expected cash flows. The resulting impairment expense of $5.6 million is included in Asset impairments on the Consolidated Statements of Comprehensive Income.

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, 2015	$ 3,486
For year ended December 31, 2016	3,743
For year ended December 31, 2017	3,326
For year ended December 31, 2018	3,126

For year ended December 31, 2019	3,053

Table of Contents

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, 2014	December 31, 2013
	(In thousands)	
NRP LP Debt:		
$425 million 9.125% senior notes, with semi-annual interest payments in April and October, maturing October 2018, $300 million issued at 99.007% and $125 million issued at 99.5%	$ 422,167	$ 297,170
Opco Debt:		
$300 million floating rate revolving credit facility, due August 2016	200,000	20,000
$200 million floating rate term loan, due January 2016	75,000	99,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018	18,467	23,084
8.38% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2019	107,143	128,571
5.05% senior notes, with semi-annual interest payments in January and July, with annual principal payments in July, maturing in July 2020	46,154	53,846
5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021	1,345	1,538
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	24,300	27,000
4.73% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2023	67,500	75,000
5.82% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2024	150,000	165,000
8.92% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2014, maturing in March 2024	45,455	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	161,538	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	46,154	50,000
NRP Oil and Gas Debt:		
Reserve-based revolving credit facility due 2019	110,000	
Total debt	1,475,223	1,165,209
Less current portion of long term debt	(80,983)	(80,983)
Long-term debt	$ 1,394,240	$ 1,084,226

Table of Contents

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 due 2018 at an offering price of 99.007% of par. 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.

In October 2014, NRP LP, together with NRP Finance as co-issuer, issued an additional $125 million of its 9.125% Senior Notes due 2018 at an offering price of 99.5% of par. The notes constitute the same series of securities as the existing $300.0 million 9.125% senior notes due 2018 issued in September 2013. Net proceeds after expenses from the issuance of the Senior Notes of approximately $122.6 million were used to fund a portion of the purchase price of NRP s acquisition of non-operated working interests in oil and gas assets located in the Williston Basin in North Dakota. The notes call for semi-annual interest payments as April 1 and October 1 of each year, beginning on April 1, 2015. 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 $80.8 million on its senior notes during the year ended December 31, 2014. The Opco senior note purchase agreement contains covenants requiring Opco to:

- Maintain a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the note purchase agreement) of no more than 4.0 to 1.0 for the four most recent quarters;
- not permit debt secured by certain liens and debt of subsidiaries to exceed 10% of consolidated net tangible assets (as defined in the note purchase agreement); and
- maintain the ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.0.

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

Revolving Credit Facility. The weighted average interest rates for the debt outstanding under Opco s revolving credit facility for the twelve months ended December 31, 2014 and year ended December 31, 2013 were 1.98% and 2.23%, respectively. Opco incurs a commitment fee on the undrawn portion of the revolving credit facility at rates ranging from 0.18% to 0.40% per annum. The facility includes an accordion feature whereby Opco may request its lenders to increase their aggregate commitment to a maximum of $500 million on the same terms.

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.

Table of Contents

Term Loan Facility. During 2013, Opco issued $200 million in term debt. The weighted average interest rates for the debt outstanding under the term loan for the twelve months ended December 31, 2014 and 2013 were 2.22% and 2.43% respectively. Opco repaid $101 million in principal under the term loan during the third quarter of 2013 and an additional $24 million during the fourth quarter of 2014. Repayment terms call for the remaining outstanding balance of $75 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 oil and gas assets in which it owns non-operated working interests. In connection with the closing of the Sanish Field acquisition in November 2014, the credit facility was amended to be a $500 million facility with an initial borrowing base of $137 million and will mature on November 12, 2019. The credit facility is secured by a first priority lien and security interest in substantially all of the assets of NRP Oil and Gas. NRP Oil and Gas is the sole obligor under its revolving credit facility, and neither the Partnership nor any of its other subsidiaries is a guarantor of such facility. At December 31, 2014, there was $110.0 million outstanding under the credit facility. The weighted average interest rate for the debt outstanding under the credit facility for the twelve months ended December 31, 2014 was 2.37%.

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

- the higher of (i) the prime rate as announced by the agent bank; (ii) the federal funds rate plus 0.50%; or (iii) LIBOR plus 1%, in each case plus an applicable margin ranging from 0.50% to 1.50%; or
- a rate equal to LIBOR, plus an applicable margin ranging from 1.50% to 2.50%.

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

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

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

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.

Table of Contents

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 and Gas Credit Facility	Total
			(In thousands)			
2015	$	$ 80,983	$	$	$	$ 80,983
2016		80,983	200,000	75,000		355,983
2017		80,983				80,983
2018	425,000(1)	80,983				505,983
2019		76,366			110,000	186,366
Thereafter		267,758				267,758
	$ 425,000	$ 668,056	$ 200,000	$ 75,000	$ 110,000	$ 1,478,056

(1) The 9.125% senior notes due 2018 were issued at a discount and as of December 31, 2014 were carried at $422.2 million.

NRP LP, Opco and NRP Oil and Gas were in compliance with all terms under their long-term debt as of December 31, 2014. Opco s revolving credit facility and term loan facility both mature in 2016. While the Partnership believes it has sufficient liquidity to meet its current financial needs, the Partnership will be required to repay or refinance the amounts outstanding under Opco s credit facilities prior to their maturity. While the Partnership believes it will be able to refinance these amounts, it may not be able to do so on terms acceptable to them, if at all, or the borrowing capacity under Opco s revolving credit facility may be substantially reduced. The Partnership s ability to refinance these amounts may depend in part on its ability to access the debt or equity capital markets, which will be challenging in the current commodity price environment.

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

	Fair Value As Of		Carrying Value As Of	
	December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013
		(In thousands)		
Assets				
Sugar Camp override, current and long-term	$ 5,162	$ 6,852	$ 4,870	$ 6,063
Liabilities				
Long-term debt, current and long-term	$ 1,096,520	$ 1,071,880	$ 1,090,223	$ 1,046,209

The fair value of the Sugar Camp override and long-term debt is estimated by discounting expected future cash flows at a comparable term risk-free treasury interest rate plus a market rate component comparable to the yield premium observed on debt securities of similar risk and maturity, which is a Level 3 measurement. Since the Partnership s credit facilities and term loan are variable rate debt, their fair values approximate their carrying amounts.

Table of Contents

12. Related Party Transactions

Reimbursements to Affiliates of the Partnership s 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 the Partnership s general partner and its affiliates. The Partnership had accounts payable of $0.4 million with Western Pocahontas Properties and $0.6 million with Quintana Minerals Corporation.

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,		
	2014	2013	2012
	(In thousands)		
Reimbursement for services	$ 11,798	$ 11,480	$ 9,791

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 LP, lease coal reserves from the Partnership, and the Partnership provides coal transportation services to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest (unaudited) in the Partnership s general partner, as well as 4,917,548 common units (unaudited) at December 31, 2014. At December 31, 2014, the Partnership had accounts receivable totaling $9.2 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 $50.0 million on the Partnership s Consolidated Balance Sheets. Revenues from the Cline affiliates are as follows:

	For The Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Coal royalty revenues	$ 52,415	$ 54,322	$ 48,567
Processing and transportation fees	20,594	19,258	21,923
Minimums recognized as revenue		3,477	17,785
Override revenue	2,847	3,226	4,066
Other revenue	5,690	8,149	
	$ 81,546	$ 88,432	$ 92,341

As of December 31, 2014, the Partnership had received $86.8 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $16.0 million was received during 2014.

During the fourth quarter of 2012, the Partnership recognized an asset impairment of $2.6 million related to the assets at the Gatling, WV location, a location leased to an affiliate of Chris Cline, due to receiving a termination notice in December 2012 that the lease was cancelled as of June 2013.

99

Table of Contents

During 2014 and 2013, the Partnership recognized gains of $5.7 million and $8.1 million on reserve swaps in Illinois with Williamson Energy, a subsidiary of Foresight Energy LP. 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 2014 and 2013 were fully mined during each of those years, while the tons exchanged are not included in the current mine plans. The gains are located in Coal related revenues on the Consolidated Statements of Comprehensive Income.

The Partnership entered into a lease agreement related to the rail loadout and associated facilities at Sugar Camp that has been accounted for as a direct financing lease. Total projected remaining payments under the lease at December 31, 2014 are $86.3 million with unearned income of $39.0 million. The net amount receivable under the lease as of December 31, 2014 was $47.3 million, of which $1.8 million is included in Accounts receivable affiliates while the remaining is included in Long-term contracts receivable affiliate on the accompanying Consolidated Balance Sheets.

In a separate transaction, the Partnership acquired a contractual overriding royalty interest from a Cline affiliate that provides for payments based upon production from specific tons at the Sugar Camp operations. This overriding royalty was accounted for as a financing arrangement and is reflected as an affiliate receivable. The net amount receivable under the agreement as of December 31, 2014 was $5.6 million, of which $1.1 million is included in Accounts receivable affiliates while the remaining is included in Long-term contracts receivable affiliate on the accompanying Consolidated Balance Sheets.

Note to Cline Trust Company, LLC

Donald R. Holcomb, one of the Partnership s directors, is a manager of Cline Trust Company, LLC, which owns approximately 5.35 million of the Partnership s common units and $20 million in principal amount of the Partnership s 9.125% Senior Notes due 2018. The members of the Cline Trust Company are four trusts for the benefit of the children of Christopher Cline, each of which owns an approximately equal membership interest in the Cline Trust Company. Mr. Holcomb also serves as trustee of each of the four trusts. Cline Trust Company, LLC purchased the $20 million of the Partnership s 9.125% Senior Notes due 2018 in the Partnership s offering of $125 million additional principal amount of such notes in October 2014 at the same price as the other purchasers in that offering. The balance on this portion of the Partnership s 9.125% Senior Notes due 2018 was $19.9 million as of December 31, 2014 and is included with the Partnership s long term debt.

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. In 2013, Taggart was sold to Forge Group, and Quintana no longer retains an interest in Taggart or Forge. The Partnership owns and leases preparation plants to Forge, which operates the plants. The lease payments were based on the sales price for the coal that was processed through the facilities.

For the years ended December 31, 2014, 2013 and 2012, the revenues from Taggart prior to the sale to Forge were as follows:

	For the Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Processing revenue	$	$ 1,761	$ 5,580

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 Coal related revenues on the Consolidated Statements of Income during 2012. The net book value of the asset sold was $7.6 million. During 2013, the note receivable that the Partnership held was paid in full.

At December 31, 2014, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp., a coal mining company traded on the TSX Venture Exchange that is one of the Partnership s lessees in Tennessee. Corbin J. Robertson III, one of the Partnership s directors, is Chairman of the Board of Corsa. Revenues from Corsa are as follows:

	For the Years Ended December 31,		
	2014	2013	2012
		(In thousands)	
Coal royalty revenues	$ 3,013	$ 4,594	$ 3,486

At each of December 31, 2013 and 2014, the Partnership also had accounts receivable totaling $ 0.3 million from Corsa.

13. Asset Retirement Obligations

The Partnership accrues a liability for legal asset retirement obligations based on an estimate of the timing and amount of settlement. The Partnership accrues for costs involving the ultimate closure of certain of its aggregate mining operations in accordance with its operating permits. These charges include costs of land reclamation, water drainage, and incremental direct administration cost of closing the operations. The Partnership also accrues for estimated costs relating to plugging wells in which it has a non-operation working interest. Upon initial recognition of an asset retirement obligation the Partnership increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to depreciation, depletion, and amortization and the initial costs are depleted over the useful lives of the related assets.

The following table presents a reconciliation of the beginning and ending carrying amounts of the Partnership s asset retirement obligations. The table does not include the short-term balance of $68,000, which is included in Accounts payable and accrued liabilities in the Consolidated Balance Sheets. The Partnership does not have any assets that are legally restricted for purposes of settling these obligations.

	For the Years Ended December 31,	
	2014	2013
	(In thousands)	
Balance, January 1	$ 39	$ 39
Liabilities incurred in current period	4,697	
Accretion expense	237	
Balance, December 31	$ 4,973	$ 39

14. 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.

Table of Contents

Environmental Compliance

The operations the Partnership s lessees conduct on its 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. See Item 1. Business Regulation and Environmental Matters. 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 leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. The Partnership makes regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. The Partnership believes that its lessees will be able to comply with existing regulations and does not expect that any lessee s failure to comply with environmental laws and regulations to have a material impact on the Partnership s financial condition or results of operations. The Partnership has neither incurred, nor is aware of, any material environmental charges imposed on the Partnership related to its properties for the period ended December 31, 2014. 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 Partnership is also responsible for losses and liabilities, including environmental liabilities that may arise from uninsured and underinsured events.

15. 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, 2014, 2013, and 2012. Revenues from these lessees are as follows:

	For the Years Ended December 31,					
	2014		2013		2012	
	Revenues	Percent	Revenues	Percent	Revenues	Percent
	(Dollars in thousands)					
Foresight Energy and affiliates	$ 81,546	20.4%	$ 88,432	24.7%	$ 92,341	24.4%
Alpha Natural Resources	$ 48,783	12.2%	$ 55,147	15.4%	$ 81,077	21.4%

In 2014, the Partnership derived 32.6% of its revenue from the two companies listed above. As a result, the Partnership has a significant concentration of revenues with those lessees, although in most cases, with the exception of the Williamson mine operated by Foresight Energy, the exposure is spread over a number of different mining operations and leases. Foresight s Williamson mine alone was responsible for approximately 10.2%, 13.0% and 12.4% of the Partnership s total revenues for 2014, 2013 and 2012, respectively.

Approximately 50% of the Partnership s accounts receivable result from amounts due from third-party companies in the coal industry, with approximately 30% of the Partnership s 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.

16. 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, 2014 are as follows:

Outstanding grants at the beginning of the period	1,012,984
Grants during the period	454,884
Grants vested and paid during the period	(285,500)
Forfeitures during the period	(28,975)
Outstanding grants at the end of the period	1,153,393

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 0.26% to 1.06% and 33.40% to 43.43%, respectively at December 31, 2014. The Partnership s cumulative average dividend rate of 7.46% was used in the calculation at December 31, 2014. The Partnership accrued expenses related to its plans to be reimbursed to its general partner of $1.0 million, $9.6 million and $2.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. In connection with the Long-Term Incentive Plans, cash payments of $6.5 million, $7.0 million and $6.6 million were paid during each of the years ended December 31, 2014, 2013, and 2012, respectively. The grant date fair value was $17.73, $25.27 and $33.38 per unit for awards in 2014, 2013 and 2012, 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, 2014, was $5.2 million.

17. Subsequent Events (Unaudited)

The following represents material events that have occurred subsequent to December 31, 2014 through the time of the Partnership s filing of its Annual Report on Form 10-K with the SEC:

Distributions

On January 20, 2015, the Partnership declared a distribution of $0.35 per unit that was paid on February 13, 2015 to unitholders of record on February 5, 2015.

Dividends and Distributions Received From Unconsolidated Equity and Other Investments

Subsequent to December 31, 2014, the Partnership received $10.9 million in cash distributions from OCI Wyoming.

Table of Contents

18. Supplemental Financial Data (Unaudited)

Shown below are selected unaudited quarterly data.

Selected Quarterly Financial Information

(In thousands, except per unit data)

2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues and other income	$ 80,309	$ 90,561	$ 91,609	$ 137,273
Depreciation, depletion and amortization	$ 14,647	$ 16,350	$ 18,621	$ 30,258
Asset impairment	$	$ 5,624	$	$ 20,585
Income from operations	$ 52,439	$ 50,403	$ 55,027	$ 31,050
Net income	$ 32,605	$ 31,407	$ 36,173	$ 8,645
Net income per limited partner unit	$ 0.29	$ 0.28	$ 0.32	$ 0.07
Weighted average number of common units outstanding	109,848	110,403	111,244	121,449

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