NATURAL RESOURCE PARTNERS LP
Form 10-K
March 06, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016 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)

1201 Louisiana Street, Suite 3400, Houston, Texas 77002
(Address of principal executive offices)
Registrant's telephone number, including area code (713) 751-7507
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 ¨ No ý
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 ý
Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark 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. ý
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.
¨ Large Accelerated Filer x 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 ý
The aggregate market value of the common units held by non-affiliates of the registrant on June 30, 2016, was $119.7 million based on a closing price on that date of $14.35 per unit as reported on the New York Stock Exchange.

As of February 24, 2017, there were 12,232,006 common units outstanding.
Documents incorporated by reference: None.

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CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

Statements included in this Annual Report on Form 10-K may constitute forward-looking statements. All statements, other than statements of historical facts, included herein or incorporated herein by reference are "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 liquidity and access to capital and financing sources;
- our ability to service our debt and make distributions to our limited partners;
- our financial strategy;
- prices of and demand for coal, trona and soda ash, construction aggregates, frac sand and other natural resources;
- estimated revenues, expenses and results of operations;
- the amount, nature and timing of capital expenditures;
- projected production levels by our lessees and VantaCore Partners LLC ("VantaCore");
- Ciner Wyoming LLC’s ("Ciner Wyoming") 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 our 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.

PART I

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

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

Partnership Structure and Management

We are a publicly traded Delaware limited partnership formed in 2002. We own, operate, manage and lease a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, construction aggregates and other natural resources. Our business is organized into three operating segments:

Coal Royalty and Other—consists primarily of coal royalty and coal related transportation and processing assets. Other assets include aggregate royalty, industrial mineral royalty, oil and gas royalty and timber. Our coal reserves are primarily located in Appalachia, the Illinois Basin and the Western United States. Our aggregates and industrial minerals are located in a number of states across the United States. Our oil and gas royalty assets are located in Louisiana.

Soda Ash—consists of our 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. Ciner 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.

VantaCore—consists of our construction materials business that operates hard rock quarries, an underground limestone mine, sand and gravel plants, asphalt plants and marine terminals. VantaCore operates in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

Our Corporate and Financing segment includes functional corporate departments that do not earn revenues. Costs incurred by these departments include corporate headquarters and overhead, financing, centralized treasury and accounting and other corporate-level activity not specifically allocated to a segment.

Our operations are conducted through Opco, and our operating assets are owned by our subsidiaries. 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 ("Adena Minerals") and the Board Representation and Observation Rights Agreement with certain entities controlled by funds affiliated with The Blackstone Group, L.P. (collectively referred to as "Blackstone") and affiliates of GoldenTree Asset Management LP (collectively referred to as "GoldenTree"), Mr. Robertson is entitled to nominate eleven 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, and one director to Blackstone.

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 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 1201 Louisiana Street, Suite 3400, Houston, Texas 77002 and our telephone number is (713) 751-7507.

2017 Recapitalization Transactions

On March 2, 2017, we completed a series of transactions in order to strengthen our balance sheet, enhance our liquidity and ultimately reposition the partnership for long-term growth, including:

- the issuance of $250 million of a new class of 12.0% preferred units representing limited partner interests in NRP, together with warrants to purchase common units, to Blackstone and GoldenTree;
- the exchange of $241 million of our 9.125% Senior Notes due 2018 (the "2018 Notes") for $241 million of a new series of 10.500% Senior Notes due 2022 (the "2022 Notes"), and the sale of $105 million of additional 2022 Notes in exchange for cash proceeds; and
- the extension of Opco's revolving credit facility to April 2020, with commitments thereunder reduced to $180 million.

We used a portion of the proceeds from these transactions to repay Opco's revolving credit facility in full and pay all fees and expenses associated with the transactions described above. We will also use a portion of the proceeds to redeem the remaining 2018 Notes. On March 3, 2017, we delivered a notice of partial redemption for $90.0 million of our outstanding 2018 Notes at a redemption price of 104.563%, plus accrued and unpaid interest to the redemption date. This partial redemption of the 2018 Notes is expected to occur on April 3, 2017. We will redeem all of the remaining 2018 Notes within 60 days after October 1, 2017 at the then-applicable price and pay all accrued and unpaid interest thereon. For more information on these transactions, including the terms of the preferred units, warrants and 2022 Notes, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—2017 Recapitalization Transactions."

2016 Asset Sales

Prior to completion of the recapitalization transactions discussed above, we had been pursuing or considering a number of actions, including dispositions of assets, in order to mitigate the effects of adverse market developments and scheduled debt principal payments. As part of this plan, we sold assets during the year ended December 31, 2016, for total gross proceeds of $181.0 million that consisted of the following:

1) Oil and gas working interest in the Williston Basin for $116.1 million gross sales proceeds. Our exit from the non-operated oil and gas working interest business represented a strategic shift to reduce debt and focus on our coal royalty, soda ash and construction aggregates business segments.
2) Oil and gas royalty and overriding royalty interests in several producing properties located in the Appalachian Basin for $36.4 million gross sales proceeds.
3) Aggregates reserves and related royalty rights at three aggregates operations located in Texas, Georgia and Tennessee for $10.0 million gross sales proceeds.
4) Mineral reserves in multiple sale transactions for cumulative $17.3 million of gross sales proceeds. These amounts primarily relate to eminent domain transactions with governmental agencies and the sale of additional oil and gas royalty interests. Additional asset sales during the year included sales of land and plant and equipment for $1.2 million of gross proceeds.

Segment and Geographic Information

The amount of total revenue for each of our operating segments in the last three years is shown below (dollars in thousands). For additional operating segment information, please see "Note 4. Segment Information" in the Notes to Consolidated Financial Statements under Item 8 in this Annual Report on Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" under Item 7 in this Annual

Report on Form 10-K, which are both incorporated herein by reference.

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	Coal Royalty and Other	Soda Ash	VantaCore	Total
2016				
Revenues	$239,183	$40,061	$120,815	$400,059
Percentage of total	60 %	10 %	30 %	
2015				
Revenues	$250,717	$49,918	$139,013	$439,648
Percentage of total	57 %	11 %	32 %	
2014				
Revenues	$267,451	$41,416	$42,051	$350,918
Percentage of total	76 %	12 %	12 %	

Coal Royalty and Other Segment

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. 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. We also own and manage coal related infrastructure assets that generate additional revenues in the Illinois Basin. In addition, we own 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.

Under our standard lease, lessees calculate royalty payments due to us and are required to report tons of minerals removed as well as the sales prices of the extracted minerals. Therefore, to a great extent, amounts reported as royalty revenue are based upon the reports of our lessees. We periodically audit this information by examining certain records and internal reports of our lessees, and we perform periodic mine inspections to verify that the information that our lessees have submitted to us is accurate. Our audit and inspection processes are designed to identify material variances from lease terms as well as differences between the information reported to us and the actual results from each property.

In addition to their royalty obligations, our lessees are often subject to pre-established minimum 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.

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. Our lessees, as operators, 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 largely reimbursed by our lessees pursuant to the terms of the various lease agreements.

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Coal Production and Reserves Information

The following table presents coal production for the year ended December 31, 2016 and coal reserves information as of December 31, 2016 for the properties that we owned by major coal region:

	Production	Proven and Probable Reserves (1)		
		Underground	Surface	Total
	(Tons in thousands)			
Appalachia:				
Northern	2,312	297,896	—	297,896
Central	13,222	749,328	240,293	989,621
Southern	2,776	73,148	17,018	90,166
Total Appalachia	18,310	1,120,372	257,311	1,377,683
Illinois Basin	8,116	302,626	5,307	307,933
Northern Powder River Basin	3,781	—	34,738	34,738
Gulf Coast	0.4	—	1,957	1,957
Total	30,207	1,422,998	299,313	1,722,311

(1) In excess of 95% of the reserves presented in this table are currently leased to third parties.

The following table presents the sulfur content, the typical quality of our coal reserves and the type of coal by major coal region as of December 31, 2016:

	Sulfur Content					Typical Quality (1)		Type of Coal	
	Compliance Coal (2)	Low (<1.0%)	Medium (1.0% to 1.5%)	High (>1.5%)	Total	Heat Content (Btu per pound)	Sulfur (%)	Steam	Met (3)
	(Tons in thousands)							(Tons in thousands)	
Appalachia									
Northern	32,807	32,807	905	264,184	297,896	12,854	2.76	265,089	32,807
Central	490,556	688,924	254,223	46,473	989,620	13,258	0.90	567,359	422,262
Southern	60,284	69,973	16,617	3,577	90,167	13,380	0.83	66,893	23,273
Total Appalachia	583,647	791,704	271,745	314,234	1,377,683	13,178	1.30	899,341	478,342
Illinois Basin	—	—	2,155	305,778	307,933	11,472	3.29	307,933	—
Northern Powder River Basin	—	34,738	—	—	34,738	8,800	0.65	34,738	—
Gulf Coast	82	1,957	—	—	1,957	6,964	0.69	1,875	82
Total	583,729	828,399	273,900	620,012	1,722,311			1,243,887	478,424

(1) Unless otherwise indicated, the coal quality information in this Annual Report and on the Form 10-K is reported on an as-received basis with an assumed moisture of 6% for Appalachian reserves, and site specific for Illinois (typically 12% moisture) and Northern Powder River Basin (typically 25%).

(2) Compliance coal, when burned, emits less than 1.2 pounds of sulfur dioxide per million Btu and 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.

(3) 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. In 2016, approximately 37% of our coal royalty revenues and approximately 35% of the related production from metallurgical coal. In prior years metallurgical coal royalty revenues accounted for a greater portion of total revenue when compared to the proportion of total production. In 2016, pricing for metallurgical coal was comparable to thermal coal pricing.

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Methodologies Used in Mineral Reserve Estimation

All of the reserves reported above are recoverable proved or probable reserves as determined by the SEC’s Industry Guide 7 and are estimated by our internal reserve engineers. The technologies and economic data used by our internal reserve engineers in the estimation of our proved or probable reserves include, but are not limited to, drill logs, geophysical logs, geologic maps including isopach, mine, and coal quality, cross sections, statistical analysis, and available public production data. 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."

Major Coal Producing 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 2016, approximately 1.5 million tons were produced from this property. We lease this property to Ohio Valley Resources, Inc., a subsidiary of Murray Energy Corporation. Coal from this property is produced from longwall mines. The royalty rate for this property is a low fixed rate per ton and has a significant effect on the per ton revenue for the region. The coal from this property is shipped by rail to utility customers.

Area F. Area F is located in Randolph and Upshur Counties, West Virginia. In 2016, approximately 0.4 million tons were produced from this property. We lease this property to Carter Roag Coal Company, a subsidiary of United Coal Company, LLC (owned by Metinvest). Production comes from the Pleasant Hill Sewell Seam deep mine and is trucked to Carter Roag’s preparation plant situated at Star Bridge, West Virginia. The coal produced from this property is shipped via the CSX railroad to Baltimore and then by ocean vessel to Metinvest's steel mills in the Ukraine.

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

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Appalachia—Central Appalachia

Contura-CAP. The Contura-CAP property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2016, approximately 3.2 million tons were produced from this property. We lease this property to subsidiaries of Contura Energy, Inc. Production comes from both underground and surface mines and is trucked to one of two preparation plants. Coal is shipped via both the CSX and Norfolk Southern railroads to utility and 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 Blackhawk Mining, LLC. In 2016, approximately 2.1 million tons were produced from the property. Both steam and metallurgical coal are produced from underground and surface mines and is transported by belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to utility customers and to various export metallurgical customers.

Lynch. The Lynch property is located in Harlan and Letcher Counties, Kentucky. In 2016, approximately 1.7 million tons were produced from this property. This property is leased to a subsidiary of Revelation Energy, LLC. Production comes from both underground and surface mines. This property has the ability to ship coal on both the CSX and Norfolk Southern railroads.

Pinnacle. The Pinnacle property is located in Wyoming and McDowell Counties, West Virginia. In 2016, approximately 1.3 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 Seneca Resources, LLC. 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.

Lone Mountain. The Lone Mountain property is located in Harlan County, Kentucky. In 2016, approximately 1.3 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 utilities and pulverized coal injection customers.

Kingston. The Kingston property is located in Fayette and Raleigh Counties, West Virginia. In 2016, approximately 0.7 million tons were produced from the property. We lease this property to a subsidiary of Alpha Natural Resources, Inc. Both steam and metallurgical coal are produced from underground and surface mines that is transported by belt or truck to a preparation plant on the property or shipped raw. Coal is shipped via both the CSX railroad and by truck to barges to steam customers and various export metallurgical customers.

Kepler/National Mines Corp. The Kepler/National Mines Corp. property is located in Wyoming County, West Virginia. In 2016, approximately 0.7 million tons were produced from the property. We lease this property to a subsidiary of Alpha Natural Resources, Inc. Metallurgical coal is produced from two underground mines that is transported by belt and truck to a preparation plant on the property. Coal is shipped via the Norfolk Southern railroad to various metallurgical customers.

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

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Appalachia—Southern Appalachia

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2016, approximately 1.5 million tons were produced from this property. We lease the property to a subsidiary of Seneca Coal Resources, LLC. Production comes from an underground longwall mine and is transported primarily by beltline to a preparation plant. Metallurgical products are then shipped via railroad and barge to both domestic and export customers.

BLC Properties. The BLC properties are located in Kentucky and Tennessee. In 2016, approximately 1.3 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.

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

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 2016, approximately 5.0 million tons were mined on the property. This production is from a longwall mine and is shipped primarily via the Canadian National railroad to domestic utility customers and to various 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 2016, approximately 2.1 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 utility customers such or loaded into barges for shipment to export customers.

Hillsboro/Deer Run. The Hillsboro property is located in Montgomery and Bond Counties, Illinois. The property is under lease to a subsidiary of Foresight Energy, and in 2016, approximately 0.1 million tons were shipped from the property. When active, production at the Deer Run mine on our Hillsboro property is 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. The Deer Run mine has been idled since March 2015 as a result of elevated carbon monoxide levels in the mine. In July 2015, we received a notice from Foresight Energy declaring a force majeure event at the mine as a result of the elevated carbon monoxide levels. We believe Foresight's claim of force majeure has no merit, and we are vigorously pursuing our claims against them through a lawsuit that we filed in November 2015. However, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us minimum deficiency payments of $7.5 million per quarter, or $30.0 million per year. For more information on the idling of the Deer Run mine, see "Item 3. Legal Proceedings" included elsewhere in this Annual Report on Form 10-K.

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. See "—Coal Transportation and Processing Assets."

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

Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2016, approximately 3.8 million tons were produced from our property by a subsidiary of Westmoreland Coal Company. 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 property in the Northern Powder River Basin:

Coal Transportation and Processing Assets

We own transportation and processing infrastructure related to certain of our coal 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 also operated by a subsidiary of Foresight Energy LP. 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, we operate the coal handling and transportation infrastructure and have subcontracted out that responsibility to a third party.

Other Assets

As of December 31, 2016, we owned an estimated 250 million tons of aggregates reserves primarily located in Kentucky, Washington and Indiana. We lease a portion of these reserves to third parties in exchange for royalty payments. We also lease approximately 90 million tons of these reserves to VantaCore's Grand Rivers operation. The structure of these leases is similar to our coal leases, and these leases typically also require minimum rental payments in addition to royalties. During 2016, our aggregates lessees produced 1.5 million tons of aggregates from these properties and we received $3.2 million in aggregates royalty revenues, including overriding royalty revenues.

Through our 51% ownership of BRP LLC ("BRP"), a joint venture with International Paper Company, we own approximately 10 million mineral acres in 31 states that include the following assets:

- approximately 300,000 gross acres of oil and gas mineral rights in Louisiana, of which over 53,000 acres were leased as of December 31, 2016;
- approximately 95,000 net mineral acres of coal rights (primarily lignite and some bituminous coal) in the Gulf Coast region, of which approximately 4,800 acres are leased in Louisiana, Alabama and Texas;
- an overriding royalty interest of 1% on approximately 25,000 mineral acres in Louisiana;
- copper rights in Michigan’s Upper Peninsula that are subject to a development agreement with a copper development company; and
- various other mineral rights including coalbed methane, metals, aggregates, water and geothermal, in several states throughout the United States.

While the vast majority of the 10 million acres remain largely undeveloped, BRP has an ongoing program to identify additional opportunities to lease its minerals to operating parties.

Soda Ash Segment

We own a 49% non-controlling equity interest in Ciner 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. Ciner 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 accessible 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.

Ciner 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. Ciner 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. The following map provides an aerial overview of Ciner 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. Ciner 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 on-site storage silos to await shipment by bulk rail or truck to distributors and end customers. Ciner 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.

Deca Rehydration. 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. Ciner Wyoming’s deca rehydration process enables Ciner Wyoming to recover soda ash from the deca-rich purged liquor as a by-product of the refining process. The soda ash contained in deca is captured by allowing the deca crystals to evaporate in the sun and separating the dehydrated crystals from the soda ash. The separated deca crystals are then blended with partially processed trona ore in the dissolving stage. This process enables Ciner 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, Ciner Wyoming has been able to reduce the amount of short tons of trona ore it takes to produce one short ton of soda ash.

Shipping and Logistics. All of the soda ash produced is shipped by rail or truck from the Green River Basin facility. For the year ended December 31, 2016, Ciner Wyoming shipped approximately 96% 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. Ciner Wyoming leases a fleet of more than 2,000 hopper cars that serve as dedicated modes of shipment to its domestic customers. For export, Ciner 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 Ciner Wyoming’s export sales. For domestic sales, Ciner Resources Corporation provides similar services.

Customers. Ciner Wyoming’s largest customer is ANSAC, which buys soda ash (through Ciner Wyoming’s sales agent) and other of its member companies for further export to its customers. ANSAC accounted for approximately 55% of Ciner Wyoming’s net sales in 2016. 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, Ciner Resources Corporation, on Ciner Wyoming’s behalf, negotiates directly with, and Ciner Wyoming exports to, customers in markets not served by ANSAC.

Leases and License. Ciner Wyoming is party to several mining leases and one license for its subsurface mining rights. Some of the leases are renewable at Ciner Wyoming’s option upon expiration. Ciner Wyoming pays royalties to the State of Wyoming, the U.S. Bureau of Land Management and Rock Springs Royalty Company, an affiliate of Anadarko Petroleum, 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 Ciner Wyoming is obligated to pay minimum royalties or annual rentals to its lessors and licensor regardless of actual sales. The royalty rates paid to Ciner Wyoming’s lessors and licensor may change upon renewal of such leases and license. Under the license with Rock Springs, the applicable royalty rate may vary based on a most favored nation clause in the license which is currently the subject of litigation in Wyoming.

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

VantaCore Segment

VantaCore is a construction materials company that we acquired on October 1, 2014. VantaCore operates four limestone quarries, one underground limestone mine, five sand and gravel plants, two asphalt plants and two marine terminals. VantaCore is headquartered in Philadelphia, Pennsylvania, and its operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana. As of December 31, 2016, VantaCore controlled approximately 400 million tons of estimated aggregates reserves, including approximately 117 million tons of reserves leased at the

Grand Rivers operation from the Coal Royalty and Other segment. The reserve estimates for each of VantaCore's properties were prepared internally and audited by an independent third party advisor. For the year ended December 31, 2016, VantaCore sold approximately 5.5 million tons of crushed stone and gravel, including brokered stone, 1.2 million tons of sand and 0.2 million tons of asphalt. VantaCore's four operating businesses are Laurel Aggregates, located in Lake Lynn, Pennsylvania, Winn Materials/McIntosh Construction, located in Clarksville, Tennessee, Grand Rivers, located in Grand Rivers, Kentucky 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 and underground mines 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 of oilfield service companies, natural gas exploration and production companies and 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 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, 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.

Grand Rivers

VantaCore purchased this 514 acre hard rock quarry operation located on the Tennessee River near Grand Rivers, Kentucky from one of NRP’s aggregates lessees that had previously idled the operation. Under VantaCore’s ownership, this operation continues to lease reserves from NRP and sell its limestone aggregates in both the local market loaded onto third party trucks and to river-based markets through a barge load out terminal.

The Grand Rivers quarry produces various grades of crushed limestone products mined through its open pit using conventional drilling, blasting and crushing methods performed by a third party mining contractor. Grand Rivers pays royalties for material produced and sold from the leased property to a subsidiary of NRP. Crushed stone is loaded into third party trucks to customers in Kentucky and barges for delivery to customers along the Mississippi River Basin and related waterways. Grand Rivers customers currently consist primarily of ready mix concrete companies and construction and contracting companies.

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, with the waste 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 for material produced and sold from the leased properties. 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.

Significant Customers

We have a significant concentration of revenues with Foresight Energy and its subsidiaries, with total revenues of $63.4 million in 2016. The exposure is spread out over four different mining operations. We are currently in disputes with and have filed two separate lawsuits against two of Foresight Energy's subsidiaries, Hillsboro Energy for breach of contract due to wrongful declaration of force majeure at the Deer Run mine, and Macoupin Energy for breach of contract for wrongful recoupment of previously paid minimum royalties. For additional information on the Deer Run mine lawsuit, see Note 15. "Major Customers" in the Notes to Consolidated Financial Statements under "Item 8. Financial Statements and Supplementary Data" and "Item 3. Legal Proceedings" included elsewhere in this Annual Report on Form 10-K.

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.

The construction aggregates industry that VantaCore operates in is highly competitive and fragmented with a large number of independent local producers 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.

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 Ciner Wyoming does. Some of Ciner 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 Ciner 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.

Title to Property

We owned a significant percentage of our coal and aggregates reserves in fee as of December 31, 2016. We lease the remainder from unaffiliated third parties, including leasing aggregates reserves for VantaCore's construction materials business. Ciner Wyoming also leases or licenses its trona reserves. 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 operation 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 polychlorinated biphenyls (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.

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 are required to 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. In many states our lessees also pay taxes into reclamation funds that states use to achieve reclamation where site specific performance bonds are inadequate to do so. Determinations by federal or state agencies that site specific bonds or state reclamation funds are inadequate could result in increased bonding costs for our lessees or even a cessation of operations if adequate levels of bonding cannot be maintained. We do not accrue for reclamation 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.

Many of the statutes discussed below also apply to VantaCore's construction aggregates mining and production operations and Ciner 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, building and operation 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.

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 August 2015, EPA published its final Clean Power Plan Rule, a multi-factor plan designed to cut carbon pollution from existing power plants, including coal-fired power plants. The rule requires improving the heat rate of existing coal-fired power plants and substituting lower carbon-emission sources like natural gas and renewables in place of coal. The rule will force 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. This rule is expected to have a material adverse effect on the demand for coal by electric power generators and is being challenged by several states, industry participants and other parties in the United States Court of Appeals for the District of Columbia Circuit. In February 2016, the Supreme Court of the United States stayed the Clean Power Plan Rule pending a decision by the District of Columbia Circuit as well as any subsequent review by the Supreme Court.

In October 2015, EPA published its final rule on performance standards for greenhouse gas emissions from new, modified, and reconstructed electric generating units. The final rule requires new steam generating units to use highly efficient supercritical pulverized coal boilers that use partial post-combustion carbon capture and storage technology. The final emission standard is less stringent than EPA had originally proposed due to updated cost assumptions, but could still have a material adverse effect on new coal-fired power plants. The final rule has been challenged by several states, industry participants and other parties in the United States Court of Appeals for the District of Columbia

Circuit, but is not subject to a stay. Oral arguments are currently scheduled for April 2017.

President Obama also announced an emission reduction agreement 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. In December 2015, the United States was one of 196 countries that participated in the Paris Climate Conference, at which the participants agreed to limit their emissions in order to limit global warming to 2°C above pre-industrial levels, with an aspirational goal of 1.5°C. While there is no way to estimate the impact of these climate pledges and agreements, they could ultimately have an adverse effect on the demand for coal, both nationally and internationally, if implemented. Prior to taking office, President Trump expressed his desire that the United States withdraw from the Paris Climate Agreement.

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.

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 Ciner Wyoming soda ash businesses.

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. In June 2015, EPA issued a new rule defining the scope of "Waters of the United States" (WOTUS) that are subject to regulation. The WOTUS rule has been challenged by a number of states and private parties and was stayed on a nationwide basis by the Sixth Circuit Court of Appeals in October 2015. In February 2016, the United States Court of Appeals for the Sixth Circuit ruled that it has exclusive jurisdiction over the challenge. In January 2017, the Supreme Court decided to hear a petition by industry groups challenging the Sixth Circuit’s jurisdictional determination. 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 group lawsuits have been filed against mine operators for allegedly violating conditions in their National Pollutant Discharge Elimination System ("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 (one of which was upheld on appeal by the United States Court of Appeals for the Fourth Circuit in January 2017). 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.

Other Regulations Affecting the Mining Industry

Mine Health and Safety Laws

The operations of our lessees, VantaCore and Ciner 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.

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. In December 2016, OSM finalized the "Stream Protection Rule," a re-written version of the stream buffer zone rule which requires coal operators to restrict mining within 100 feet of waterways. The rule also requires states to impose additional information gathering and monitoring at and around coal mining sites and mandates new financial assurance and reclamation requirements. The rule was repealed by Congress in February 2017; however, to the extent the rule is ever reinstated, it 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.

Employees and Labor Relations

As of January 31, 2017, affiliates of our general partner employed 63 people who directly supported our operations. None of these employees were subject to a collective bargaining agreement. We employed 221 people who supported VantaCore's construction aggregates mining and production operations. None of these employees were subject to a collective bargaining agreement.

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 charter for our Audit Committee. 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

To the extent our board of directors deems appropriate, it may determine to decrease the amount of our quarterly distribution or suspend or eliminate the distribution altogether. In addition, our debt agreements and our partnership agreement place restrictions on our ability to pay the quarterly distribution under certain circumstances.

Because distributions on the common units are dependent on the amount of cash we generate, distributions 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, including distributions on the preferred units, 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. Following the recapitalization transactions, we still have significant debt service obligations and obligations to pay cash distributions on our preferred units. To the extent our board of directors deems appropriate, it may determine to decrease the amount of the quarterly distribution on our common units or suspend or eliminate the distribution on our common units altogether. In addition, because our unitholders are required to pay income taxes on their respective shares of our taxable income, you may be required to pay taxes in excess of any future distributions we make. Your share of our portfolio income may be taxable to you even though you receive other losses from our activities. See "—Tax Risks to Common Unitholders—You are required to pay taxes on your share of our income even if you do not receive any cash distributions from us."

The agreements governing our indebtedness and preferred units restrict our ability to raise, and in some cases continue to pay, distributions on our common units. Opco's revolving credit agreement, the indenture governing our 2022 Notes and our partnership agreement each require that we meet certain consolidated leverage tests in order to raise our quarterly distribution on the common units above the current level of $0.45 per quarter. The maximum leverage covenant under Opco's revolving credit facility will step down permanently from 4.0x to 3.0x if we increase the common unit distribution above the current level. In addition, under our partnership agreement, to the extent we have paid any distributions on the preferred units in kind ("PIK units"), and such PIK units are still outstanding at any time after January 1, 2022, we will be prohibited from making any distributions with respect to our common units until we have redeemed all such PIK units in cash. For more information on restrictions on our ability to make distributions on our common units, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—2017 Recapitalization Transactions" and "Item 8. Financial Statements and Supplementary Data—Note 11. Debt and Debt—Affiliate."

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

As of December 31, 2016, we and our subsidiaries had approximately $1.1 billion of total indebtedness. Following the execution of our recapitalization transactions, we and our subsidiaries had approximately $944 million of total indebtedness. The terms and conditions governing our indebtedness, including the indentures for NRP's 2018 Notes and 2022 Notes, and Opco's revolving credit facility and senior notes:

- 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;

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- 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, including payment of distributions on the preferred units. If we do not have sufficient funds, we may be required to refinance all or part of our existing debt, borrow more money, or sell assets or raise equity at unattractive prices. 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. While we intend to make these payments using cash from operations, we may not be able to refinance these amounts on terms acceptable to us, if at all. 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 comply with the financial and other restrictive covenants in our debt agreements will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations.

Foresight Energy is our largest lessee, and ongoing disputes with them could have an adverse effect on our financial condition and results of operations. In addition, if the Deer Run mine remains idled for an extended period or does not resume operations, our financial condition and results of operations could be adversely affected.

Foresight Energy is our largest lessee, and in 2016, we derived approximately 16% of our revenues from them. We are currently in disputes with them with respect to two of their four mining operations in which we have an interest. Foresight Energy’s Deer Run mine (which we also refer to as our Hillsboro property) has been idled for almost two years as a result of elevated carbon monoxide levels at the mine. Foresight Energy has declared a force majeure event at the Deer Run mine and failed to make $46.0 million in required minimum deficiency payments to us as of the date hereof. Such amount is expected to increase by $7.5 million for each quarter during which mining operations continue to be idled. We have filed a lawsuit against Foresight Energy and Hillsboro Energy to recover the amounts owed to us and compel them to make the required minimum deficiency payments under the lease. We do not currently have an estimate as to when the mine will resume coal production. If the mine remains idled for an extended period or if the mine is permanently closed, our financial condition could be adversely affected. In addition, we have also filed a lawsuit against Foresight Energy’s Macoupin subsidiary, which has failed to comply with the terms of the coal mining, rail loadout and rail loop leases at the Macoupin mine by incorrectly recouping previously paid minimum royalties, resulting in a cumulative $6.2 million negative cash impact to us. See "Item 3. Legal Proceedings" included elsewhere in this Annual Report on Form 10-K for more information on our lawsuits against Foresight Energy. These ongoing disputes and further deterioration of our relationship with our largest lessee could have a material adverse effect on our financial condition and results of operations.

Depressed coal prices have 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. Steam coal prices remain at levels close to or below the level of operating costs for a number of our lessees. While metallurgical coal prices have improved in recent months, we do not expect the current pricing environment to be sustained, and prices could decline substantially. 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 reached multi-year lows during 2016 due to global economic conditions. While metallurgical coal prices have improved in recent months, we do not expect the current pricing environment to be sustained. 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. In addition, during 2015 and 2016, a number of coal producers filed for protection under U.S. bankruptcy laws, including several of our coal lessees. Although many of our lessees have emerged from bankruptcies, more of our lessees may file for bankruptcy in the future, which will create additional uncertainty as to the future of operations on our properties and could have a material adverse effect on our business and results of operations.

Lower prices reduce the quantity of coal that may be economically produced from our properties, which in turn reduces 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. Future impairment analyses could result in additional downward adjustments to the carrying value of our assets.

Mining operations are subject to operating risks that could result in lower revenues to us.

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.

Under the current regulatory environment, 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.

VantaCore currently operates four hard rock quarries, one underground limestone mine, six sand and gravel plants, two asphalt plants and two marine terminals. As an operator of these assets, we are 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.

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 have resulted in and will continue to 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 August 2015, EPA published its final Clean Power Plan Rule, a multi-factor plan designed to cut carbon pollution from existing power plants, including coal-fired power plants. The rule requires improving the heat rate of existing coal-fired power plants and substituting lower carbon-emission sources like natural gas and renewables in place of coal. The rule will force 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. This rule is being challenged by industry participants and other parties. In February, 2016, the Supreme Court of the United States stayed the Clean Power Plan Rule pending a decision by the District of Columbia Circuit as well as any subsequent review by the Supreme Court.

In October 2015, EPA published its final rule on performance standards for greenhouse gas emissions from new, modified, and reconstructed electric generating units. The final rule requires new steam generating units to use highly efficient supercritical pulverized coal boilers that use partial post-combustion carbon capture and storage technology. The final emission standard is less stringent than EPA had originally proposed due to updated cost assumptions, but could still have a material adverse effect on new coal-fired power plants. The final rule has been challenged by several states, industry participants and other parties in the United States Court of Appeals for the District of Columbia Circuit, but is not subject to a stay. Oral arguments are currently scheduled for April 2017.

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.

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 Ciner 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.

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.

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 Ciner Wyoming's soda ash production operations. If the market price for soda ash declines, Ciner Wyoming's sales will decrease. Historically, the global market and, to a lesser extent, the domestic market for soda ash have been volatile, and those markets are likely to remain volatile in the future. The prices Ciner Wyoming receives for its soda ash depend on numerous factors beyond Ciner Wyoming's control, including worldwide and regional economic and political conditions impacting 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. Competition from increased use of glass substitutes, such as plastic and recycled glass, has had a negative effect on demand for soda ash. Substantial or extended declines in prices for soda ash could have a material adverse effect on our results of operations. In addition, Ciner Wyoming relies on natural gas as the main energy source in its soda ash production process. Accordingly, high natural gas prices increase Ciner 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.

The construction aggregates industry is highly fragmented with a large number of independent local producers 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.

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 Ciner Wyoming. We have limited approval rights with respect to Ciner Wyoming, and our partner controls most business decisions, including decisions with respect to distributions and capital expenditures. Adverse developments in Ciner Wyoming’s business would result in decreased distributions to NRP. 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.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal, soda ash, construction aggregates, and other minerals from our properties.

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

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

In addition, Ciner 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 Ciner 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. Ciner 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 Ciner Wyoming's facility, and alternative methods of transportation are impracticable or cost-prohibitive. During 2016, Ciner Wyoming shipped substantially all of its soda ash via a Union Pacific rail line. Ciner Wyoming relies on the rail line to service its facilities under a contract that expires in 2017. Any substantial interruption in or increased costs related to the transportation of Ciner Wyoming's soda ash or the failure to renew the rail contract on favorable terms could have a material adverse effect on our financial condition and results of operations.

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, reserve engineering requires subjective estimates of underground accumulations of coal, aggregates and industrial minerals, and assumptions and are by nature imprecise. Our reserve estimates may vary substantially from the actual amounts of coal, aggregates and industrial minerals 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.

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
- 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.

The preferred units are senior in right of distributions and liquidation and upon conversion, would result in the issuance of additional common units in the future, which could result in substantial dilution of our common unitholders' ownership interests.

The preferred units are a new class of partnership interests that rank senior to our common units with respect to distribution rights and rights upon liquidation. We are required to pay quarterly distributions on the preferred units (plus any PIK Units issued in lieu of preferred units) in an amount equal to 12.0% per year prior to paying any distributions on our common units. The preferred units also rank senior to the common units in right of liquidation, and will be entitled to receive a liquidation preference in any such case.

The preferred units may also be converted into common units under certain circumstances. The number of common units issued in any conversion will be based on the then-current trading price of the common units at the time of conversion. Accordingly, the lower the trading price of our common units at the time of conversion, the greater the number of common units that will be issued upon conversion of the preferred units, which would result in greater dilution to our existing common unitholders. Dilution has the following effects on our common unitholders:

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

In addition, to the extent the preferred units are converted into more than 66 2/3% of our common units, the holders of the preferred will have the right to remove our general partner.

We may issue additional common units or preferred 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 (including additional preferred 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; and
- 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:

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- Excluding our VantaCore business, 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.

In addition, as a result of the purchase of the Preferred Units, Blackstone has certain consent rights and board appointment and observation rights. GoldenTree also has more limited consent rights. In the exercise of their applicable consent rights and/or board rights, conflicts of interest could arise between us and our general partner on the one hand, and Blackstone or GoldenTree on the other hand.

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 debt agreements. During the continuance of an event of default under our debt agreements, 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. In addition, upon a change of control, the holders of the preferred units would have the right to require us to redeem the preferred units at the liquidation preference or convert all of their preferred units into common units. 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 Internal Revenue Service ("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 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 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. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior 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.

In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code of 1986, as amended (the "Final Regulations") were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We anticipate that we will continue to meet the qualifying income exception for publicly traded partnership under the Final Regulations.

However, any interpretation of or modification to the 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 partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any similar or future legislative changes could negatively impact the value of an investment in our common units.

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.

You are required to pay taxes on your share of our income even if you do not receive any cash distributions from us. Your share of our portfolio income may be taxable to you even though you receive other losses from our activities.

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.

For unitholders subject to the passive loss rules, our current operations include portfolio activities (such as our coal and mineral royalties business) and passive activities (such as our soda ash and aggregates businesses). Any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset (i) our portfolio income, including income related to our coal and mineral royalties business, (ii) a unitholder's income from other passive activities or investments, including investments in other publicly traded partnerships, or (iii) a unitholder's salary or active business income. Thus, your share of our portfolio income may be subject to federal income tax, regardless of other losses you may receive from us.

We may engage in transactions to reduce our indebtedness and manage our liquidity that generate taxable income (including income and gain from the sale of properties and cancellation of indebtedness income) allocable to unitholders, and income tax liabilities arising therefrom may exceed any distributions made with respect to your units.

In response to current market conditions, we may engage in transactions to reduce our leverage and manage our liquidity that would result in income and gain to our unitholders without a corresponding cash distribution. For example, we may sell assets and use the proceeds to repay existing debt, in which case, you could be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, we may pursue opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt that would result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as ordinary taxable income. Unitholders may be allocated income and gain from these transactions, and income tax liabilities arising therefrom may exceed any distributions we make to you. The ultimate tax effect of any such income allocations will depend on the unitholder's individual tax position, including, for example, the availability of any suspended passive losses that may offset some portion of the allocable income. Unitholders may, however, be allocated substantial amounts of ordinary income subject to taxation, without any ability to offset such allocated income against any capital losses attributable to the unitholder’s ultimate disposition of its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them.

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.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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 (the "Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

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

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. The partnership technically terminated on August 31, 2016, as a result of the sale or exchange of 50% or more of our capital and profits interest during the prior twelve month period. Any technical termination, such as the one occurring in 2016, 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 taxable income for the applicable year. 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 has 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.

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.

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.

In November 2015, we filed a lawsuit against Foresight Energy's subsidiary, Hillsboro Energy LLC ("Hillsboro"), in the Circuit Court of the Fourth Judicial Circuit in Montgomery County, Illinois. The lawsuit alleges, among other items, breach of contract by Hillsboro resulting from a wrongful declaration of force majeure at Hillsboro's Deer Run mine in July 2015. In late March 2015, elevated carbon monoxide readings were detected at the Deer Run mine, and coal production at the mine was idled. In July 2015, we received the notice declaring a force majeure event at the mine as a result of the elevated carbon monoxide levels. We believe the force majeure claim by Hillsboro has no merit and we are vigorously pursuing recovery against them. However, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us minimum deficiency payments of $7.5 million per quarter, or $30.0 million per year. Foresight Energy's failure to make the deficiency payment with respect to the second, third and fourth quarters of 2015 and each quarter of 2016 resulted in a cumulative $46.0 million negative cash impact to us. Such amount will increase for each quarter during which mining operations continue to be idled. We do not currently have an estimate as to when the mine will resume coal production. If the mine remains idled for an extended period or if the mine is permanently closed, our financial condition could be adversely affected.

In April 2016, we filed a lawsuit against Macoupin Energy, LLC ("Macoupin"), a subsidiary of Foresight Energy, in Macoupin County, Illinois. The lawsuit alleges that Macoupin has failed to comply with the terms of its coal mining, rail loadout and rail loop leases by incorrectly recouping previously paid minimum royalties. Foresight Energy’s failure to properly calculate its recoupable balance and failure to make payments in accordance with these lease agreements has resulted in a cumulative $6.2 million negative cash impact to us. While the Partnership plans to pursue its claim, a valuation allowance for the receivable amount has been recorded.

For more information regarding certain other legal proceedings involving NRP, see "Note 14. Commitments and Contingencies" included in the Notes to Consolidated Financial Statements in "Item 8. Financial Statements and Supplementary Data" included elsewhere in this Annual Report on Form 10-K.

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.

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 1, 2017, there were approximately 26,500 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, 2015 to December 31, 2016, and the quarterly cash distribution declared and paid with respect to each quarter per common unit. The information presented in the tables below has been adjusted to give retroactive effect to the one-for-ten reverse unit split that was effective on February 17, 2016.

	Price Range		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2015					
First Quarter	$98.10	$63.80	$0.90	5/5/2015	5/14/2015
Second Quarter	$74.50	$36.10	$0.90	8/5/2015	8/14/2015
Third Quarter	$38.00	$22.10	$0.45	11/5/2015	11/13/2015
Fourth Quarter	$29.90	$10.00	$0.45	2/5/2016	2/12/2016
2016					
First Quarter	$13.86	$5.00	$0.45	5/5/2016	5/13/2016
Second Quarter	$18.92	$7.13	$0.45	8/5/2016	8/12/2016
Third Quarter	$29.85	$13.97	$0.45	11/7/2016	11/14/2016
Fourth Quarter	$40.00	$25.11	$0.45	2/7/2017	2/14/2017

Cash Distributions to Partners

	General Partner (1)	Limited Partners (2)	Total Distributions
	(in thousands)		
2015 Distributions	$1,434	$70,324	$ 71,758
2016 Distributions	$451	$22,014	$ 22,465

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

(2) Includes $0.9 million and $0.3 million distributions to our general partner on 156,000 common units beneficially owned by our general partner in 2015 and 2016, respectively.

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."

	For the Years Ended December 31,				
	2016	2015	2014	2013	2012
	(in thousands, except per unit data)				
Total revenues and other income	$400,059	$439,648	$350,918	$352,739	$379,147
Asset impairments	$16,926	$384,545	$26,209	$734	$2,568
Income (loss) from operations	$185,745	$(170,427)	$176,140	$233,740	$267,165
Net income (loss) from continuing operations	$95,214	$(260,171)	$96,713	$169,621	$213,355
Net income from continuing operations excluding impairments (1)	$112,140	$124,374	$122,922	$170,355	$215,923
Net income (loss) from discontinued operations	$1,678	$(311,549)	$12,117	$2,457	$—
Net income (loss)	$96,892	$(571,720)	$108,830	$172,078	$213,355
Per common unit amounts (basic and diluted)					
Net income (loss) from continuing operations	$7.65	$(20.78)	$8.37	$15.17	$19.70
Net income (loss) from discontinued operations	$0.13	$(24.97)	$1.05	$0.22	$—
Net income (loss)	$7.78	$(45.75)	$9.42	$15.39	$19.70
Distributions paid	$1.80	$2.70	$14.00	$22.00	$22.00
Average number of common units outstanding (2)	12,232	12,232	11,326	10,958	10,603
Net cash provided by (used in)					
Operating activities of continuing operations	$100,643	$168,512	$192,164	$246,891	$271,408
Investing activities of continuing operations	$59,943	$6,985	$(169,512)	$(230,436)	$(212,733)
Financing activities of continuing operations	$(161,419)	$(183,264)	$(65,986)	$(73,574)	$(124,173)
Distributable Cash Flow (1)	$271,415	$176,617	$196,929	$306,690	$296,106
Adjusted EBITDA (1)	$255,471	$262,639	$263,871	$328,690	$328,116
Cash and cash equivalents	$40,371	$41,204	$48,971	$92,305	$149,424
Total assets	$1,444,681	$1,670,035	$2,430,819	$1,980,354	$1,760,381
Long-term debt	$987,400	$1,206,611	$1,270,573	$1,072,962	$892,986
Partners' capital	$151,530	$76,336	$720,155	$616,789	$617,447

(1) See "—Non-GAAP Financial Measures" below.

(2) The unit numbers in the table above give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

Non-GAAP Financial Measures

Distributable Cash Flow

Our Distributable Cash Flow ("DCF") represents net cash provided by operating activities of continuing operations, plus returns of unconsolidated equity investments, proceeds from sales of assets, including those included in discontinued operations, and returns of long-term contract receivables—affiliate; less maintenance capital expenditures and distributions to non-controlling interest. DCF 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. DCF may not be calculated the same for us as for other companies. DCF is a supplemental liquidity measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to assess the Partnership's ability to make cash distributions to our unitholders and our general partner and repay debt. The following table (in thousands) reconciles net cash provided by operating activities of continuing operations (the most comparable GAAP financial measure) to Distributable Cash Flow for the years ended December 31, 2016, 2015, 2014, 2013 and 2012:

	Year Ended December 31,				
	2016	2015	2014	2013	2012
Net cash provided by operating activities of continuing operations	$100,643	$168,512	$192,164	$246,891	$271,408
Add: return of unconsolidated equity investment	—	—	3,633	48,833	—
Add: proceeds from sale of PP&E	1,350	11,024	1,006	—	11,277
Add: proceeds from sale of mineral rights	61,033	3,505	412	10,929	13,545
Add: proceeds from sale of assets included in discontinued operations	109,872	—	—	—	—
Add: return on long-term contract receivables—affiliate	2,968	2,463	1,904	2,558	2,669
Less: maintenance capital expenditures (1)	(4,451)	(6,143)	(1,216)	—	—
Less: distributions to non-controlling interest	—	(2,744)	(974)	(2,521)	(2,793)
Distributable Cash Flow	$271,415	$176,617	$196,929	$306,690	$296,106

(1) Maintenance capital expenditures primarily consist of costs to maintain the long-term productive capacity of VantaCore.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income (loss) from continuing operations less equity earnings from unconsolidated investment, gain on reserve swaps and income to non-controlling interest; plus distributions from equity earnings in unconsolidated investment, interest expense, depreciation, depletion and amortization and asset impairments.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations. 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 (loss), the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDA reported by different companies.

Adjusted EBITDA is a supplemental performance measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis.

The following table (in thousands) reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA for the years ended December 31, 2016, 2015, 2014, 2013 and 2012:

	Year Ended December 31,				
	2016	2015	2014	2013	2012
Net income (loss) from continuing operations	$95,214	$(260,171)	$96,713	$169,621	$213,355
Less: equity earnings from unconsolidated investment	(40,061)	(49,918)	(41,416)	(34,186)	—
Less: gain on reserve swaps	—	(9,290)	(5,690)	(8,149)	—
Add: distributions from equity earnings in unconsolidated investment	46,550	46,795	46,638	72,946	—
Add: interest expense	90,570	89,762	79,523	64,357	53,972
Add: depreciation, depletion and amortization	46,272	60,916	61,894	63,367	58,221
Add: asset impairments	16,926	384,545	26,209	734	2,568
Adjusted EBITDA	$255,471	$262,639	$263,871	$328,690	$328,116

Adjusted EBITDA presented in the table above differs from the EBITDDA definitions contained in Opco's debt agreements. See Note 11. "Debt and Debt—Affiliate" included in the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" included elsewhere in this Annual Report on Form 10-K for a description of Opco's debt agreements.

Net Income from Continuing Operations Excluding Impairments

Net income from continuing operations excluding impairments is a non-GAAP financial measure that we define as net income (loss) from continuing operations plus asset impairments. Net income from continuing operations excluding impairments, 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. Net income excluding impairments should not be considered in isolation or as a substitute for operating income (loss), net income (loss), cash flows provided by operating, investing and financial activities, or other income or cash flow statement data prepared in accordance with GAAP. Our management team believes net income excluding impairments is useful in evaluating our financial performance because asset impairments are irregular non-cash charges and excluding these from net income allows us to better compare results period-over-period.The following table (in thousands) reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to net income excluding impairment for the years ended December 31, 2016, 2015, 2014, 2013 and 2012:

	Year Ended December 31,				
	2016	2015	2014	2013	2012
Net income (loss) from continuing operations	$95,214	$(260,171)	$96,713	$169,621	$213,355
Add: asset impairments	16,926	384,545	26,209	734	2,568
Net income from continuing operations excluding impairments	$112,140	$124,374	$122,922	$170,355	$215,923

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion and analysis presents management’s view of our business, financial condition and overall performance and should be read in conjunction with our consolidated financial statements and footnotes included elsewhere in this filing. Our discussion and analysis consists of the following subjects:
•Executive Overview
•Results of Operations
•Liquidity and Capital Resources
•Off-Balance Sheet Transactions
•Inflation
•Environmental Regulation
•Related Party Transactions
•Summary of Critical Accounting Estimates
•Recent Accounting Standards

As used in this Item 7, unless the context otherwise requires: "we," "our," "us" and the "Partnership" refer to Natural Resource Partners L.P. and, where the context requires, our subsidiaries. References to "NRP" and "Natural Resource Partners" refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC or any of Natural Resource Partners L.P.’s subsidiaries. References to "Opco" refer to NRP (Operating) LLC, a wholly owned subsidiary of NRP, and its subsidiaries. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP. NRP Finance Corporation ("NRP Finance") is a wholly owned subsidiary of NRP and a co-issuer with NRP on the 9.125% senior notes due 2018 (the "2018 Notes") and the 10.50% senior notes due 2022 (the "2022 Notes").

Executive Overview

We are a diversified natural resource company engaged principally in the business of owning, managing and leasing a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, construction aggregates and other natural resources. Our common units trade on the New York Stock Exchange under the symbol "NRP".

Our business is organized into three operating segments:

Coal Royalty and Other—consists primarily of coal royalty and coal related transportation and processing assets. Other assets include aggregate royalty, industrial mineral royalty, oil and gas royalty and timber. Our coal reserves are primarily located in Appalachia, the Illinois Basin and the Western United States. Our aggregates and industrial minerals are located in a number of states across the United States. Our oil and gas royalty assets are located in Louisiana.

Soda Ash—consists of our 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. Ciner 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.

VantaCore—consists of our construction materials business that operates hard rock quarries, an underground limestone mine, sand and gravel plants, asphalt plants and marine terminals. VantaCore operates in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

For the year ended December 31, 2016, our financial results included (in thousands):

Revenues and other income	$400,059
Net income from continuing operations	$95,214
Adjusted EBITDA (1)	$255,471
Operating cash flow provided by continuing operations	$100,643
Investing cash flow provided by continuing operations	$59,943
Financing cash flow (used in) continuing operations	$(161,419)
Distributable Cash Flow ("DCF") (1)	$271,415

(1) See "—Results of Operations" below for additional information regarding non-GAAP financial measures and reconciliations to the most comparable GAAP financial measures.

2017 Recapitalization Transactions

We have been pursuing or considering a number of actions in order to mitigate the effects of adverse market developments and scheduled debt principal payments since April 2015 when we announced our long-term strategic plan to strengthen our balance sheet and enhance our liquidity. On March 2, 2017, we completed the following transactions that achieved these objectives and will ultimately reposition the partnership for long-term growth:

- the issuance of $250 million of a new class of 12.0% preferred units representing limited partner interests in NRP, together with warrants to purchase common units, to certain entities controlled by funds affiliated with The Blackstone Group, L.P. (collectively referred to as "Blackstone") and certain affiliates of GoldenTree Asset

Management LP (collectively referred to as "GoldenTree");

- the exchange of $241 million of our 9.125% Senior Notes due 2018 (the "2018 Notes") for $241 million of a new series of 10.500% Senior Notes due 2022 (the "2022 Notes"), and the sale of $105 million of additional 2022 Notes in exchange for cash proceeds; and
- the extension of Opco’s revolving credit facility (the "Opco Credit Facility") to April 2020, with commitments thereunder reduced to $180 million.

We used a portion of the proceeds from these transactions to repay Opco’s revolving credit facility in full and pay all fees and expenses associated with the transactions described above. We will also use a portion of the proceeds to redeem the remaining 2018 Notes. On March 3, 2017, we delivered a notice of partial redemption for $90.0 million of our outstanding 2018 Notes at a redemption price of 104.563%, plus accrued and unpaid interest to the redemption date. This partial redemption of the 2018 Notes is expected to occur on April 3, 2017. We will redeem all of the remaining 2018 Notes within 60 days after October 1, 2017 at the then-applicable price and pay all accrued and unpaid interest thereon.

For more information on these transactions, including the terms of the preferred units, warrants and 2022 Notes, see "—Liquidity and Capital Resources—2017 Recapitalization Transactions."

2016 Asset Sales

Prior to completion of these recapitalization transactions, we had been pursuing or considering a number of actions, including dispositions of assets, in order to mitigate the effects of adverse market developments and scheduled debt principal payments. As part of this plan, we sold assets during the year ended December 31, 2016, for total gross proceeds of $181.0 million that consisted of the following:

- Oil and gas working interest in the Williston Basin for $116.1 million gross sales proceeds that marked our exit from the non-operated oil and gas working interest business.
- Oil and gas royalty and overriding royalty interests in several producing properties located in the Appalachian Basin for $36.4 million gross sales proceeds.
- Aggregates reserves and related royalty rights at three aggregates operations located in Texas, Georgia and Tennessee for $10.0 million gross sales proceeds.
- Mineral reserves in multiple sale transactions for cumulative $17.3 million of gross sales proceeds. These amounts primarily relate to eminent domain transactions with governmental agencies and the sale of additional oil and gas royalty interests. Additional asset sales during the year included sales of land and plant and equipment for $1.2 million of gross proceeds.

Current Liquidity

As of December 31, 2016, we had a total of $40.4 million of cash and cash equivalents. During the year ended December 31, 2016, we reduced our debt by approximately $248.1 million by repaying $85.0 million of the NRP Oil and Gas reserve based lending facility in full (the "RBL Facility"), $82.9 million of the Opco Private Placement Notes (as defined below), $80.0 million of the Opco Credit Facility and $0.2 million of Opco's utility local improvement obligation.

In March 2017, we increased our liquidity through the completion of the recapitalization transactions described above, including by repaying borrowings outstanding under the Opco Credit Facility in full. In addition to enhancing our liquidity, these recapitalization transactions reduced our 2018 debt maturities by $575 million through the extension of debt principal payments from 2018 to 2020 and 2022. Even with these meaningful improvements to our liquidity and balance sheet, we continue to have substantial debt outstanding and intend to continue to use cash from operations to deleverage our balance sheet over time. While we have a diversified portfolio of assets, we face challenges in coal and other commodity markets. Our going concern analysis included an analysis of these relevant conditions and events and our ability to meet our obligations and remain in compliance with our debt covenants within one year after the issuance date of these financial statements. We expect that we will meet all of our obligations, including scheduled principal and interest payments on our debt and required distributions on the preferred units, comply with all covenants contained in our debt agreements and that we will continue as a going concern.

Current Results/Market Outlook

Coal Royalty and Other Business Segment

For the year ended December 31, 2016, our Coal Royalty and Other business segment financial results included the following (in thousands):

Revenues and other income	$239,183
Net income from continuing operations	$161,816
Adjusted EBITDA (1)	$209,443
Operating cash flow provided by continuing operations	$134,490
Investing cash flow provided by continuing operations	$65,057
Financing cash flow provided by continuing operations	$16
DCF (1)	$199,547

(1) See "—Results of Operations" below for additional information regarding non-GAAP financial measures and reconciliations to the most comparable GAAP financial measures.

In the fourth quarter of 2016, we began to realize the benefits of the dramatic increase in metallurgical coal prices as well as the improvement in the thermal coal markets. A number of our lessees were able to take advantage of the improved markets and lock in tonnage commitments for 2017 at substantially higher prices than they realized in 2016. While spot metallurgical prices have recently retreated from the highs reached in the fourth quarter, we believe that that global supply/demand dynamic will support long-term metallurgical coal prices well above the lows hit in the first half of 2016. We derived approximately 37% of our coal royalty revenues and approximately 35% of the related production from metallurgical coal during the year ended December 31, 2016. The domestic thermal coal markets have also shown modest improvements, as production cuts over the last year have rationalized coal stockpiles. Although a mild winter has tempered demand for thermal coal, natural gas prices remain higher than 2016, causing thermal coal to be more competitive for electricity generation as compared to recent years. In addition, we expect the actions of the Trump Administration to ease the regulatory burdens on the coal industry, reducing the production costs and increasing the competitiveness of our lessees against natural gas. Despite these improvements, producers of Central Appalachian thermal coal continue to face challenges, as many still have large debt burdens and their production costs remain high relative to sales prices. We have successfully navigated the bankruptcies of several of our lessees and have had substantially all of our leases assumed or assigned and received substantially all past-due amounts in these bankruptcies.

Production from our Illinois Basin properties decreased by 27% during the year ended December 31, 2016 as compared to the year ended December 31, 2015. Substantially all of the decrease is attributable to the idling of Foresight Energy's Deer Run mine (which we also refer to as our Hillsboro property) during 2016. In July 2015, we received a notice from Foresight Energy declaring a force majeure event at the Deer Run mine after elevated levels of carbon monoxide were detected. We believe Foresight's claim of force majeure has no merit and we are vigorously pursuing our claims against them through a lawsuit filed in November 2015. However, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us quarterly minimum deficiency payments with respect to the Deer Run mine until mining resumes. Under the lease for the Deer Run mine, Foresight Energy is required to make minimum deficiency payments to us of $7.5 million per quarter, or $30.0 million per year. Foresight Energy’s failure to make the deficiency payments with respect to the second, third and fourth quarters of 2015 and all four quarters of 2016 resulted in a cumulative negative cash impact to us of $46.0 million. Such amount will increase for each quarter during which mining operations continue to be idled. Foresight Energy is continuing efforts to reenter the mine, but we do not know when, or if, mining activities at the Deer Run mine will recommence.

Soda Ash Business Segment

For the year ended December 31, 2016, our Soda Ash business segment financial results included the following (in thousands):

Revenues and other income	$40,061
Net income from continuing operations	$40,061
Adjusted EBITDA (1)	$46,550
Operating cash flow provided by continuing operations	$46,550
Financing cash flow used by continuing operations	$(7,229)
DCF (1)	$46,550

(1) See "—Results of Operations" below for additional information regarding non-GAAP financial measures and reconciliations to the most comparable GAAP financial measures.

Income from our trona mining and soda ash refinery investment was lower year-over-year for the year ended December 31, 2016. This decrease is primarily related to lower international prices compared to the prior year, in addition to higher royalty and G&A costs. These decreases were partially offset by an increase in soda ash volumes sold compared to the prior year. Ciner Resources LP, our partner that controls and operates Ciner Wyoming, is a publicly traded master limited partnership that depends on distributions from Ciner Wyoming in order to make distributions to its public unitholders.

VantaCore Business Segment

For the year ended December 31, 2016, our VantaCore business segment financial results included the following (in thousands):

Revenues and other income	$120,815
Net income from continuing operations	$4,438
Adjusted EBITDA (1)	$20,009
Operating cash flow provided by continuing operations	$20,400
Investing cash flow used by continuing operations	$(5,114)
Financing cash flow used by continuing operations	$(1,825)
DCF (1)	$16,243

(1) See "—Results of Operations" below for additional information regarding non-GAAP financial measures and reconciliations to the most comparable GAAP financial measures.

VantaCore’s construction aggregates mining and production business is largely dependent on the strength of the local markets that it serves. VantaCore’s Laurel Aggregates operation in southwestern Pennsylvania serves producers and oilfield service companies operating in the Marcellus and Utica Shales and was impacted during the year ended December 31, 2016 by the slowing pace of exploration and development of natural gas in those areas due to low natural gas prices. Increased local construction activity partially offset these declines during the year ended December 31, 2016, but we expect that Laurel’s business will continue to be impacted by decreased natural gas development activities. While VantaCore's production and revenues have declined in 2016 compared to 2015, its cost management efforts have enabled the business to maintain its profitability.

Discontinued Operations

In July 2016, NRP Oil and Gas closed on the sale of its non-operated oil and gas working interest assets in the Williston Basin for $116.1 million in gross sales proceeds. Our exit from our non-operated oil and gas working interest business represented a strategic shift to reduce debt and focus on our soda ash, coal royalty and construction aggregates business segments. As a result, we have classified the assets and liabilities, operating results and cash flows of our non-operated oil and gas working interest assets as discontinued operations in our consolidated financial statements for all periods presented.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Revenues and Other Income

Revenues and other income decreased $39.5 million, or 9%, from $439.6 million in the year ended December 31, 2015 to $400.1 million in the year ended December 31, 2016. The following table shows our diversified sources of natural resource revenues and other income by business segment for the year ended December 31, 2016 and 2015 (in thousands except for percentages):

	Coal Royalty and Other	Soda Ash	VantaCore	Total
2016				
Revenues and other income	$239,183	$40,061	$120,815	$400,059
Percentage of total	60 %	10 %	30 %	
2015				
Revenues and other income	$250,717	$49,918	$139,013	$439,648
Percentage of total	57 %	11 %	32 %	

The changes in revenue and other income is discussed for each of the our business segments below:

Coal Royalty and Other

Revenues and other income related to our Coal Royalty and Other segment decreased $11.5 million, or 5%, from $250.7 million in the year ended December 31, 2015 to $239.2 million in the year ended December 31, 2016.

The table below presents coal production and coal royalty revenues (including affiliates) derived from our major coal producing regions and the significant categories of other coal royalty and other revenues:

	For the Year Ended December 31, 2016	2015	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data) (Unaudited)			
Coal production (tons)				
Appalachia				
Northern	2,312	9,562	(7,250)	(76)%
Central	13,222	16,862	(3,640)	(22)%
Southern	2,776	3,803	(1,027)	(27)%
Total Appalachia	18,310	30,227	(11,917)	(39)%
Illinois Basin	8,116	11,173	(3,057)	(27)%
Northern Powder River Basin	3,781	4,905	(1,124)	(23)%
Gulf Coast	0.4	740	(740)	(100)%
Total coal production	30,207	47,045	(16,838)	(36)%
Coal royalty revenue per ton				
Appalachia				
Northern	$1.15	$0.28	$0.87	311 %
Central	3.64	3.85	(0.21)	(5)%
Southern	3.84	4.57	(0.73)	(16)%
Illinois Basin	3.66	3.94	(0.28)	(7)%
Northern Powder River Basin	2.81	2.54	0.27	11 %
Gulf Coast	3.28	3.47	(0.19)	(5)%
Coal royalty revenues				
Appalachia				
Northern	$2,667	$2,672	$(5)	— %
Central	48,119	64,877	(16,758)	(26)%
Southern	10,660	17,390	(6,730)	(39)%
Total Appalachia	61,446	84,939	(23,493)	(28)%
Illinois Basin	29,680	44,063	(14,383)	(33)%
Northern Powder River Basin	10,637	12,443	(1,806)	(15)%
Gulf Coast	1	2,570	(2,569)	(100)%
Total coal royalty revenue	$101,764	$144,015	$(42,251)	(29)%
Other revenues				
Minimums recognized as revenue	$64,591	$15,489	$49,102	317 %
Transportation and processing fees	19,336	22,033	(2,697)	(12)%
Property tax revenue	10,457	11,258	(801)	(7)%
Wheelage	2,374	3,166	(792)	(25)%
Coal override revenue	2,281	2,920	(639)	(22)%
Lease assignment fee	—	21,000	(21,000)	(100)%

Gain on reserve swap	—	9,290	(9,290)	(100)%
Hard mineral royalty revenues	3,163	8,090	(4,927)	(61)%
Oil and gas royalty revenues	3,537	4,364	(827)	(19)%
Other	2,612	2,156	456	21 %
Total other revenues	$108,351	$99,766	$8,585	9 %
Coal royalty and other income	210,115	243,781	(33,666)	(14)%
Gain on coal royalty and other segment asset sales	29,068	6,936	22,132	319 %
Total coal royalty and other segment revenues and other income	$239,183	$250,717	$(11,534)	(5)%

Total coal production decreased 16.8 million tons, or 36%, from 47.0 million tons in the year ended December 31, 2015 to 30.2 million tons in the year ended December 31, 2016. Total coal royalty revenues decreased $42.3 million, or 29%, from $144.0 million in the year ended December 31, 2015 to $101.8 million in the year ended December 31, 2016. Total coal production and coal royalty revenue decreases were driven by downward pressure in the coal markets as described above, with Central Appalachian thermal coal producers in particular continuing to face challenges, as their production costs remain high relative to sales prices.

Total other revenues increased $8.6 million in 2016 compared to 2015 primarily as a result of the agreements with certain lessees to either modify or terminate existing coal related leases that resulted in the recognition of $40.5 million of deferred revenue. This increase was partially offset by non-recurring revenue transactions in 2015 that included $21.0 million in lease assignment fees and $9.3 million gain on reserve swap. Other revenues were also decreased $4.9 million in 2016 primarily as a result of the sale of our aggregates royalty assets in the first quarter of 2016.

Gain on coal royalty and other segment asset sales increased $22.1 million primarily as a result of the following asset sales during the first quarter of 2016:
1)Oil and gas royalty and overriding royalty interests in several producing properties located in the Appalachian Basin for $36.4 million gross sales proceeds. The effective date of the sale was January 1, 2016, and we recorded an $18.6 million gain from this sale.
2)Aggregate reserves and related royalty rights in the Coal Royalty and Other segment at three aggregates operations located in Texas, Georgia and Tennessee for $10.0 million gross sales proceeds. The effective date of the sale was February 1, 2016, and we recorded a $1.5 million gain from this sale.

Soda Ash

Revenues and other income related to our equity investment in Ciner Wyoming decreased $9.8 million, or 20%, from $49.9 million in the year ended December 31, 2015 to $40.1 million in the year ended December 31, 2016. This decrease is primarily related to lower international prices compared to the prior year, in addition to higher royalty and G&A costs. These decreases were partially offset by an increase in soda ash volumes sold compared to the prior year.

VantaCore

Revenues and other income related to our VantaCore segment decreased $18.2 million, or 13%, from $139.0 million in the year ended December 31, 2015 to $120.8 million in the year ended December 31, 2016. This decrease is primarily due to a decrease in construction aggregates and brokered stone revenue as well as lower delivery and fuel income year-over-year. Tonnage sold by the VantaCore segment decreased 0.4 million tons, or 5% from 7.4 million tons in the year ended December 31, 2015 to 7.0 million tons in the year ended December 31, 2016 as a result of decreased construction aggregates demand in the oil and gas services sector that was partially offset by increased aggregates sales into the construction market.

Operating and Maintenance Expenses (including affiliates)

Operating and maintenance expenses (including affiliates) decreased $21.8 million, or 14%, from $152.3 million in the year ended December 31, 2015 to $130.5 million in the year ended December 31, 2016. This decrease is primarily related to the following:

VantaCore

Operating and maintenance expenses (including affiliates) in our VantaCore segment decreased $16.2 million, or 14% from $116.9 million in the year ended December 31, 2015 to $100.7 million in the year ended December 31, 2016. This decrease is primarily due to the decline in materials cost as a result of the decrease in construction aggregates and brokered stone volume year-over-year due to reduced demand in the oil and gas sector and a decrease in delivery and fuel costs due to the lower construction aggregates production and brokered stone purchases year-over-year partially and effective variable cost management.

Depreciation, Depletion and Amortization ("DD&A") Expense

DD&A expense decreased $14.6 million, or 24%, from $60.9 million in the year ended December 31, 2015 to $46.3 million in the year ended December 31, 2016. This decrease is primarily related to the reduced cost basis of our coal and aggregates royalty mineral rights due to the asset impairments recorded in the third and fourth quarters of 2015 and the decline in coal royalty production year-over-year.

General and Administrative (including affiliates) ("G&A") Expense

Corporate and financing G&A expense (including affiliates) includes corporate headquarters, financing and centralized treasury and accounting. These costs increased $8.3 million, or 67%, from $12.3 million in the year ended December 31, 2015 to $20.6 million in the year ended December 31, 2016. This increase is primarily related to increased legal and consulting fees associated with the implementation of our long-term plan to strengthen our balance sheet, reduce debt and enhance our liquidity and increased LTIP expense as a result of our unit price increasing in 2016 compared to decreasing unot price in 2015 and the accelerated recognition of our LTIP awards granted in 2016

Asset Impairments

Asset impairments decreased $367.6 million, or 96%, from $384.5 million in the year ended December 31, 2015 to $16.9 million in the year ended December 31, 2016. We recorded the following asset impairments during the years ended December 31, 2016 and 2015 (in thousands):

	For the Year Ended December 31,	
Impaired Assets	2016	2015
Coal Royalty and Other		
Mineral Rights	$13,801	$371,397
Plant and Equipment	2,060	6,930
Total Coal Royalty and Other Impairment	$15,861	$378,327
VantaCore		
Plant and Equipment	$1,065	$692
Goodwill	—	5,526
Total VantaCore Impairment	$1,065	$6,218
Total impairment	$16,926	$384,545

Coal Royalty and Other

Asset impairments decreased $362.4 million, or 96%, from $378.3 million in the year ended December 31, 2015 to $15.9 million in the year ended December 31, 2016. This decrease is primarily related to $257.5 million in coal property impairment, $70.5 million in oil and gas property impairment and $43.4 million in aggregate property impairment recorded during the year ended December 31, 2015 as compared to $12.1 million in coal property impairment and $1.7 million in aggregate property impairment recorded during the year ended December 31, 2016. The impairments in 2015 primarily resulted from the continued deterioration and expectations of further reductions in global and domestic coal demand due to reduced global steel demand, sustained low natural gas prices, and continued regulatory pressure on the electric power generation industry.

VantaCore

Asset impairments decreased $5.1 million, or 82%, from $6.2 million in the year ended December 31, 2015 to $1.1 million in the year ended December 31, 2016. This decrease is primarily related to the $5.5 million write off of goodwill during the year ended December 31, 2015.

Income (Loss) from Discontinued Operations

Income from discontinued operations increased $313.2 million, from a loss of $311.5 million in the year ended December 31, 2015 to income of $1.7 million in the year ended December 31, 2016. The change in income (loss) from discontinued operations is primarily related to the $297.0 million asset impairments recorded in 2015, the sale of our non-operated oil and gas working interest assets that was completed in July 2016 with an effective date of April 1, 2016 and the $8.3 million gain on sale for the year ended December 31, 2016.

Adjusted EBITDA (Non-GAAP Financial Measure)

The following table (in thousands) reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA by business segment for the years ended December 31, 2016 and 2015:

	Operating Segments				
For the Year Ended	Coal Royalty and Other	Soda Ash	VantaCore	Corporate and Financing	Total
December 31, 2016					
Net income (loss) from continuing operations	$161,816	$40,061	$ 4,438	$(111,101)	$95,214
Less: equity earnings from unconsolidated investment	—	(40,061)	—	—	(40,061)
Add: distributions from unconsolidated investment	—	46,550	—	—	46,550
Add: interest expense	—	—	—	90,570	90,570
Add: depreciation, depletion and amortization	31,766	—	14,506	—	46,272
Add: asset impairment	15,861	—	1,065	—	16,926
Adjusted EBITDA	$209,443	$46,550	$ 20,009	$(20,531)	$255,471
December 31, 2015					
Net income (loss) from continuing operations	$(208,248)	$49,918	$ 251	$(102,092)	$(260,171)
Less: equity earnings from unconsolidated investment	—	(49,918)	—	—	(49,918)
Less: gain on reserve swap	(9,290)	—			(9,290)
Add: distributions from unconsolidated investment	—	46,795	—	—	46,795
Add: interest expense	—	—	—	89,762	89,762
Add: depreciation, depletion and amortization	45,338	—	15,578	—	60,916
Add: asset impairment	378,327	—	6,218	—	384,545
Adjusted EBITDA	$206,127	$46,795	$ 22,047	$(12,330)	$262,639

Adjusted EBITDA decreased $7.1 million, or 3%, from $262.6 million in the year ended December 31, 2015 to $255.5 million in the year ended December 31, 2016. The decrease is primarily a result of $42.3 million in reduced coal royalty revenue resulting from decreased coal production and coal royalty revenue per ton driven by the continued pressure on U.S. coal producers as described above, $21.0 million in non-recurring 2015 lease assignment fees, $4.9 million of reduced aggregates royalty revenue in 2016 due to decreased 2016 aggregates production and sales and $8.3 million of additional G&A expense in 2016 compared to 2015 as described above. These decreases were partially offset by a $49.1 million increase in minimums recognized as revenue primarily as a result of coal lease modifications or terminations that resulted in our lessee forfeiting their minimum royalty balances and $22.2 million of additional gains on asset sales as compared to the same period in 2015. "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Adjusted EBITDA" for an explanation of Adjusted EBITDA.

Distributable Cash Flow (Non-GAAP Financial Measure)

The following table (in thousands) presents the three major categories of the statement of cash flows by business segment for the years ended December 31, 2016 and 2015:

For the Year Ended	Operating Segments Coal Royalty and Other	Soda Ash	VantaCore	Corporate and Financing	Total
December 31, 2016					
Net cash provided by (used in) operating activities of continuing operations	$134,490	$46,550	$20,400	$(100,797)	$100,643
Net cash provided by (used in) investing activities of continuing operations	65,057	—	(5,114)	—	59,943
Net cash provided by (used in) financing activities of continuing operations	16	(7,229)	(1,825)	(152,381)	(161,419)
December 31, 2015					
Net cash provided by (used in) operating activities of continuing operations	$204,934	$43,029	$23,605	$(103,056)	$168,512
Net cash provided by (used in) investing activities of continuing operations	15,805	—	(8,820)	—	6,985
Net cash provided by (used in) financing activities of continuing operations	(2,744)	—	—	(180,520)	(183,264)

The following table (in thousands) reconciles net cash provided by operating activities (the most comparable GAAP financial measure) by business segment to DCF for the years ended December 31, 2016 and 2015:

	Operating Segments				
For the Year Ended	Coal Royalty and Other	Soda Ash	VantaCore	Corporate and Financing	Total
December 31, 2016					
Net cash provided by (used in) operating activities of continuing operations	$134,490	$46,550	$20,400	$(100,797)	$100,643
Add: proceeds from sale of PP&E	1,084	—	266	—	1,350
Add: proceeds from sale of mineral rights	61,033	—	—	—	61,033
Add: proceeds from sale of assets included in discontinued operations	—	—	—	—	109,872
Add: return on long-term contract receivables—affiliate	2,968	—	—	—	2,968
Less: maintenance capital expenditures	(28)	—	(4,423)	—	(4,451)
Distributable Cash Flow	$199,547	$46,550	$16,243	$(100,797)	$271,415
December 31, 2015					
Net cash provided by (used in) operating activities of continuing operations	$204,934	$43,029	$23,605	$(103,056)	$168,512
Add: proceeds from sale of PP&E	10,100	—	924	—	11,024
Add: proceeds from sale of mineral rights	3,505	—	—	—	3,505
Add: return on long-term contract receivables—affiliate	2,463	—	—	—	2,463
Less: maintenance capital expenditures	(416)	—	(5,727)	—	(6,143)
Less: distributions to non-controlling interest	(2,744)	—	—	—	(2,744)
Distributable Cash Flow	$217,842	$43,029	$18,802	$(103,056)	$176,617

DCF increased $94.8 million, or 54%, from $176.6 million in the year ended December 31, 2015 to $271.4 million in the year ended December 31, 2016. This increase is due primarily to the $109.9 million net cash proceeds from the sale of our discontinued operation in addition to $61.0 million in net cash proceeds from sales of mineral rights in 2016. These increases were partially offset by lower coal royalty production, lower coal royalty revenue per ton and less minimum payments received from our coal leases. These decreases are driven by the continued pressure on U.S. coal producers as described above. See "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Distributable Cash Flow" for an explanation of Distributable Cash Flow.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Revenues and Other Income

Revenues and other income increased $88.7 million, or 25%, from $350.9 million in the year ended December 31, 2014 to $439.6 million in the year ended December 31, 2015. The following table shows our diversified sources of natural resource revenues and other income by business segment for the years ended December 31, 2015 and 2014 (in thousands except for percentages):

	Coal Royalty and Other	Soda Ash	VantaCore	Total
2015				
Revenues	250,717	49,918	139,013	439,648
Percentage of total	57 %	11 %	32 %	
2014				
Revenues	267,451	41,416	42,051	350,918
Percentage of total	76 %	12 %	12 %	

The changes in revenue and other income is discussed for each of the our business segments below:

Coal Royalty and Other

Revenues and other income related to our Coal Royalty and Other segment decreased $16.8 million, or 6%, from $267.5 million in 2014 to $250.7 million in 2015.

The table below presents coal royalty production and revenues derived from our major coal producing regions and the significant categories of other coal royalty and other revenues:

	For the Years Ended December 31,		Increase (Decrease)	Percentage Change
	2015	2014		
	(In thousands, except percent and per ton data)			
	(Unaudited)			
Coal production (tons)				
Appalachia				
Northern	9,562	9,339	223	2 %
Central	16,862	20,092	(3,230)	(16)%
Southern	3,803	3,914	(111)	(3)%
Total Appalachia	30,227	33,345	(3,118)	(9)%
Illinois Basin	11,173	13,177	(2,004)	(15)%
Northern Powder River Basin	4,905	2,844	2,061	72 %
Gulf Coast	740	1,093	(353)	(32)%
Total coal production	47,045	50,459	(3,414)	(7)%
Coal royalty revenue per ton				
Appalachia				
Northern	$0.28	$0.92	$(0.64)	(70)%
Central	3.85	4.46	(0.61)	(14)%
Southern	4.57	5.18	(0.61)	(12)%
Illinois Basin	3.94	4.10	(0.16)	(4)%
Northern Powder River Basin	2.54	2.74	(0.20)	(7)%
Gulf Coast	3.47	3.47	—	— %
Coal royalty revenues				
Appalachia				
Northern	$2,672	$8,621	$(5,949)	(69)%
Central	64,877	89,627	(24,750)	(28)%
Southern	17,390	20,292	(2,902)	(14)%
Total Appalachia	84,939	118,540	(33,601)	(28)%
Illinois Basin	44,063	54,049	(9,986)	(18)%
Northern Powder River Basin	12,443	7,804	4,639	59 %
Gulf Coast	2,570	3,793	(1,223)	(32)%
Total coal royalty revenue	$144,015	$184,186	$(40,171)	(22)%
Other revenues				
Coal override revenue	$2,920	$4,601	$(1,681)	(37)%
Transportation and processing fees	22,033	22,048	(15)	— %
Minimums recognized as revenue	15,489	6,659	8,830	133 %
Lease assignment fee	21,000	—	21,000	100 %
Gain on reserve swap	9,290	5,690	3,600	63 %

Wheelage	3,166	3,442	(276)	(8)%
Hard mineral royalty revenues	8,090	12,073	(3,983)	(33)%
Oil and gas royalty revenues	4,364	10,732	(6,368)	(59)%
Property tax revenue	11,258	13,609	(2,351)	(17)%
Other	2,156	3,045	(889)	(29)%
Total other revenues	$99,766	$81,899	$17,867	22 %
Coal royalty and other income	243,781	266,085	(22,304)	(8)%
Gain on coal royalty and other segment asset sales	6,936	1,366	5,570	408 %
Total coal royalty and other segment revenues and other income	$250,717	$267,451	$(16,734)	(6)%

Total coal production decreased 3.4 million tons, or 7%, from 50.4 million tons in 2014 to 47.0 million tons in 2015. Total coal royalty revenues decreased $40.2 million, or 22%, from $184.2 million in 2014 to $144.0 million in 2015. During 2015, depressed coal prices negatively affected our coal related revenues. During the year ended December 31, 2015 as compared to 2014, total coal production and total coal royalty revenues were down in Appalachia, the Illinois Basin and the Gulf Coast, while we saw a significant increase in the Northern Powder River Basin. All Appalachian regions saw a decrease in coal royalty revenues during the year with coal royalty revenues in Northern Appalachia down 69% despite a 2% increase in production from that area. We saw a decrease in the average coal revenue per ton throughout all of our regions, with the exception of the Gulf Coast whose average coal revenue per ton remained flat, for the year ended December 31, 2015 when compared to the year ended December 31, 2014.

Other coal royalty and other income increased $17.9 million, or 22%, from $81.9 million in 2014 to $99.8 million in 2015. This increase is primarily a result of two lease assignment fee payments received in 2015 totaling $21.0 million, an $8.8 million increase in minimums recognized as revenue and a $3.6 million increase in reserve swap gains year-over-year. These increases were partially offset by decreased oil and gas royalty revenue as a result of lower commodity prices year-over-year and decreases in hard mineral royalty revenues, property taxes and override revenue in 2015 when compared to 2014.

Soda Ash

Revenues and other income related to our Soda Ash segment increased $8.5 million, or 21%, from $41.4 million in 2014 to $49.9 million in 2015. This increase is primarily related to our allocated percentage of Ciner Wyoming's $15.0 million increase in income year-over-year. For the year ended December 31, 2015, we received $46.8 million in cash distributions from Ciner Wyoming and for the year ended December 31, 2014, we received $46.6 million in cash distributions.

VantaCore

Tonnage sold by the VantaCore segment increased 5.1 million tons from 2.3 million tons in 2014 to 7.4 million tons in 2015. Revenues and other income related to our VantaCore segment increased $96.9 million, or 231%, from $42.1 million in 2014 to $139.0 million in 2015. This increase is due to the fact that VantaCore was acquired in the fourth quarter of 2014.

Operating and Maintenance Expenses (including affiliates)

Operating and maintenance expenses (including affiliates) increased $76.2 million, or 100%, from $76.1 million in 2014 to $152.3 million in 2015. This increase is primarily related to the following:

VantaCore

Operating and maintenance expenses in our VantaCore segment increased $78.2 million from $38.7 million in 2014 to $116.9 million in 2015. This increase is due to the fact that 2014 results only include three months of VantaCore activity as compared to twelve months in 2015.

Depreciation, Depletion and Amortization ("DD&A") Expense

DD&A expense decreased $1.0 million from $61.9 million in 2014 to $60.9 million in 2015. This decrease is primarily related to the following:

Coal Royalty and Other

DD&A expense for our Coal Royalty and Other segment decreased $13.3 million, or 23%, from $58.6 million in 2014 to $45.3 million in 2015. This decrease was primarily the result of the reduction in depletion expense on the assets that were impaired during the third and fourth quarters of 2015 and reduced production year-over-year.

VantaCore

DD&A expense for our VantaCore segment increased $12.3 million from $3.3 million in 2014 to $15.6 million in 2015. This increase was due to the fact that 2014 results only include three months of activity as compared to a full year in 2015.

General and Administrative (including affiliates) ("G&A") Expense

Corporate and financing G&A expense includes corporate headquarters, financing and centralized treasury and accounting. These costs increased $1.8 million, or 17%, from $10.5 million in 2014 to $12.3 million in 2015. This increase was primarily due to an increase in salaries, bonus and benefits, consulting, rent and legal fees. This increase was partially offset by a decrease in LTIP expense as a result of the decline in unit price year-over-year.

Asset Impairment

Asset impairment expense increased $358.3 million from $26.2 million in 2014 to $384.5 million in 2015. We recorded the following asset impairments during the years ended December 31, 2015 and 2014 (in thousands):

	For the Year Ended December 31,	
Impaired Assets	2015	2014
Coal Royalty and Other		
Mineral Rights	$371,397	$19,806
Plant and Equipment	6,930	779
Intangible Assets	—	5,624
Total Coal Royalty and Other Impairment	$378,327	$26,209
VantaCore		
Plant and Equipment	$692	$—
Goodwill	5,526	—
Total VantaCore Impairment	$6,218	$—
Total impairment	$384,545	$26,209

Coal Royalty and Other

Asset impairment expense related to our Coal Royalty and Other segment increased $352.1 million from $26.2 million in 2014 to $378.3 million in 2015. This increase was primarily due to the significant impairment expense taken in the third quarter 2015. Coal property impairments primarily resulted from idled operations in Appalachia combined with the continued deterioration in the coal markets and expectations of further reductions in global and domestic coal demand due to reduced global steel demand, low natural gas prices, and continued regulatory pressure on the electric power generation industry. Oil and gas royalty property impairments primarily results from declines in future expected realized commodity prices and reduced expected drilling activity on our acreage. Aggregate royalty property impairments primarily resulted from greenfield development projects that have not performed as projected, leading to recent lease concessions on minimums and royalties combined with the continued regional market decline for certain properties. During the fourth quarter of 2015, we recognized an additional $8.2 million impairment expense on our coal properties as a result of continued market declines and $4.7 million impairment expense related to coal processing and transportation assets as well as obsolete equipment at our Logan office. During the second quarter of 2015 we recorded a $2.3 million impairment expense related to a coal preparation plant.

VantaCore

The $6.2 million impairment expense in 2015 was related to a $5.5 million write off of goodwill as well as a $0.7 million impairment related to obsolete plant and equipment.

Interest Expense

Interest expense increased $10.3 million, or 13%, from $79.4 million in 2014 to $89.7 million in 2015. This increase was primarily the result of additional debt incurred to complete acquisitions in the fourth quarter of 2014.

Income (Loss) from Discontinued Operations

Income from discontinued operations decreased $323.6 million, from income of $12.1 million in 2014 to a loss of $311.5 million in 2015. The change in income (loss) from discontinued operations primarily related to asset impairments recorded in 2015 due to the declines in future expected realized commodity prices and reduced expected drilling activity and reduced oil and gas prices in 2015 compared to 2014.

Adjusted EBITDA (Non-GAAP Financial Measure)

The following table (in thousands) reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA by business segment for the years ended December 31, 2015 and 2014:

	Operating Segments				
For the Year Ended	Coal Royalty and Other	Soda Ash	VantaCore	Corporate and Financing	Total
December 31, 2015					
Net income (loss) from continuing operations	$(208,248)	$49,918	$ 251	$(102,092)	$(260,171)
Less: equity earnings from unconsolidated investment	—	(49,918)	—	—	(49,918)
Less: gain on reserve swap	(9,290)	—			(9,290)
Add: distributions from unconsolidated investment	—	46,795	—	—	46,795
Add: interest expense	—	—	—	89,762	89,762
Add: depreciation, depletion and amortization	45,338	—	15,578	—	60,916
Add: asset impairment	378,327	—	6,218	—	384,545
Adjusted EBITDA	$206,127	$46,795	$ 22,047	$(12,330)	$262,639
December 31, 2014					
Net income (loss) from continuing operations	$145,237	$41,416	$ 32	$(89,972)	$96,713
Less: equity earnings from unconsolidated investment	—	(41,416)	—	—	(41,416)
Less: gain on reserve swap	(5,690)	—	—	—	(5,690)
Add: distributions from unconsolidated investment	—	46,638	—	—	46,638
Add: interest expense	—	—	—	79,523	79,523
Add: depreciation, depletion and amortization	58,598	—	3,296	—	61,894
Add: asset impairment	26,209	—	—	—	26,209
Adjusted EBITDA	$224,354	$46,638	$ 3,328	$(10,449)	$263,871

Adjusted EBITDA decreased $1.3 million from $263.9 million in 2014 to $262.6 million in 2015. The decrease is mainly related to declines in our Coal Royalty and Other segment, partially offset by higher income from our VantaCore business that was acquired in October 2014. 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.

Distributable Cash Flow (Non-GAAP Financial Measure)

The following table (in thousands) presents the three major categories of the statement of cash flows by business segment for the years ended December 31, 2015 and 2014:

	Operating Segments				
For the Year Ended	Coal Royalty and Other	Soda Ash	VantaCore	Corporate and Financing	Total
December 31, 2015					
Net cash provided by (used in) operating activities of continuing operations	$204,934	$43,029	$23,605	$(103,056)	$168,512
Net cash provided by (used in) investing activities of continuing operations	$15,805	$—	$(8,820)	$—	$6,985
Net cash provided by (used in) financing activities of continuing operations	$(2,744)	$—	$—	$(180,520)	$(183,264)
December 31, 2014					
Net cash provided by (used in) operating activities of continuing operations	$238,564	$42,516	$2,746	$(91,662)	$192,164
Net cash provided by (used in) investing activities of continuing operations	$(2,067)	$3,633	$(171,078)	$—	$(169,512)
Net cash provided by (used in) financing activities of continuing operations	$(974)	$—	$—	$(65,012)	$(65,986)

The following table (in thousands) reconciles net cash provided by operating activities (the most comparable GAAP financial measure) by business segment to DCF for the years ended December 31, 2015 and 2014:

	Operating Segments				
For the Year Ended	Coal Royalty and Other	Soda Ash	VantaCore	Corporate and Financing	Total
December 31, 2015					
Net cash provided by (used in) operating activities of continuing operations	$204,934	$43,029	$23,605	$(103,056)	$168,512
Add: proceeds from sale of PP&E	10,100	—	924	—	11,024
Add: proceeds from sale of mineral rights	3,505	—	—	—	3,505
Add: return on long-term contract receivables—affiliate	2,463	—	—	—	2,463
Less: maintenance capital expenditures	(416)	—	(5,727)	—	(6,143)
Less: distributions to non-controlling interest	(2,744)	—	—	—	(2,744)
Distributable Cash Flow	$217,842	$43,029	$18,802	$(103,056)	$176,617
December 31, 2014					
Net cash provided by (used in) operating activities of continuing operations	$238,564	$42,516	$2,746	$(91,662)	$192,164
Add: return of unconsolidated equity investment	—	3,633	—	—	3,633
Add: proceeds from sale of PP&E	968	—	38	—	1,006
Add: proceeds from sale of mineral rights	412	—	—	—	412
Add: return on long-term contract receivables—affiliate	1,904	—	—	—	1,904
Less: maintenance capital expenditures	(316)	—	(900)	—	(1,216)
Less: distributions to non-controlling interest	(974)	—	—	—	(974)
Distributable Cash Flow	$240,558	$46,149	$1,884	$(91,662)	$196,929

Distributable Cash Flow for 2015 decreased $20.3 million, or 10%, from $196.9 million in 2014 to $176.6 million in 2015. This decrease is due primarily to a reduction in cash provided by our coal operations, partially offset by our VantaCore business that was acquired in October 2014. 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.

Liquidity and Capital Resources

2017 Restructuring Transactions

The following discussion describes the recapitalization transactions completed on March 2, 2017 and the terms of the preferred units, warrants to purchase common units and debt securities issued in connection therewith.

Issuance of Preferred Units and Warrants

We issued $250 million of Class A Convertible Preferred Units representing limited partner interests in NRP (the "Preferred Units") to Blackstone and GoldenTree (together the "Preferred Purchasers") pursuant to a Preferred Unit and Warrant Purchase Agreement. We issued 250,000 Preferred Units to the Preferred Purchasers at a price of $1,000 per Preferred Unit (the "Per Unit Purchase Price"), less a 2.5% structuring and origination fee. The Preferred Units entitle the Preferred Purchasers to receive cumulative dividends at a rate of 12% per year, up to one half of which NRP may pay in additional Preferred Units (such additional Preferred Units, the "PIK Units"). We also issued two tranches of warrants (the "Warrants") to purchase common units to the Preferred Purchasers (Warrants to purchase 1.75 million common units with a strike price of $22.81 and Warrants to purchase 2.25 million common units with a strike price of $34.00). The Warrants may be exercised by the holders thereof at any time before the eighth anniversary of the closing date. Upon exercise of the Warrants, we may, at our option, elect to settle the Warrants in common units or cash, each on a net basis.

The Preferred Units have a perpetual term, unless converted or redeemed as described below. The Preferred Units (including any PIK Units) are convertible into common units at the election of the holders (1) after the fifth anniversary and prior to the eighth anniversary of the issue date at a 7.5% discount to the volume weighted average trading price of our common units (the "VWAP") for the 30 trading days immediately prior to the notice of conversion if the 30-day VWAP immediately prior to such notice is greater than $51.00 (subject to a maximum of 33% of the Preferred Units per year) and (2) after the eighth anniversary of the issue date at a 10% discount to the VWAP for the 30 trading days immediately prior to the notice of conversion. Instead of issuing common units pursuant to clause (1) of the preceding sentence, we have the option to redeem the Preferred Units proposed to be converted for cash at a price equal to the Per Unit Purchase Price, plus the value of any accrued and unpaid distributions. To the extent the holders of the Preferred Units have not elected to convert their Preferred Units by the twelfth anniversary of the issue date, we have the right to force conversion of the Preferred Units into common units at a 10% discount to the VWAP for the 30 trading days immediately prior to the notice of conversion. In addition, we have the ability to redeem at any time (subject to compliance with our debt agreements) all or any portion of the Preferred Units (including PIK Units) for cash at the agreed upon per unit amount, which is calculated as the Per Unit Purchase Price multiplied by (i) prior to the third anniversary of the closing date, 1.50, (ii) on or after the third anniversary of the closing date and prior to the fourth anniversary of the closing date, 1.70 and (iii) on or after the fourth anniversary of the closing date, 1.85.

The terms of the Preferred Units contain certain restrictions on our ability to pay distributions on our common units. To the extent that either (i) our consolidated Leverage Ratio (as defined in the Restated Partnership Agreement) is greater than 3.25x, or (ii) the ratio of our Distributable Cash Flow to cash distributions made or proposed to be made is less than 1.2x (in each case, with respect to the most recently completed four-quarter period), we may not increase the quarterly distribution above $0.45 per quarter without the approval of the holders of a majority of the outstanding Preferred Units. In addition, if at any time after January 1, 2022, any PIK Units are outstanding, we may not make distributions on our common units until we have redeemed all PIK Units for cash.

The holders of the Preferred Units have the right to vote with holders of NRP’s common units on an as-converted basis and have other customary approval rights with respect to changes of the terms of the Preferred Units. In addition, Blackstone has certain approval rights over certain matters, including:

- the incurrence of new indebtedness, subject to certain exceptions;
- material changes to NRP’s business;
- acquisitions and divestitures in excess of certain dollar thresholds;
- amendments to material contracts resulting in a cash impact to NRP in excess of certain dollar thresholds;
- settlement of any litigation or regulatory matter resulting in cash payments by NRP in excess of certain thresholds; and

- amendments to related party contracts outside of the ordinary course of business.

GoldenTree also has more limited approval rights that will expand once Blackstone's ownership goes below the Minimum Preferred Unit Threshold (as defined below). The Preferred Purchaser Approval Rights are not transferrable without our consent. In addition, the Preferred Purchaser Approval Rights held by Blackstone and GoldenTree will terminate at such time that Blackstone (together with their affiliates) or GoldenTree (together with their affiliates), as applicable, no longer own at least 20% of the total number of Preferred Units issued on the closing date, together with all PIK Units that have been issued but not redeemed (the "Minimum Preferred Unit Threshold"). To the extent any Preferred Units that have converted into common units are still held by the applicable Preferred Purchaser (or its affiliates), such common units will be deemed to represent a number of Preferred Units based on the weighted average number of common units issued in each conversion and will count towards the Minimum Preferred Unit Threshold.

The foregoing terms of the Preferred Units are reflected in our Fifth Amended and Restated Agreement of Limited Partnership, dated as of March 2, 2017, which is filed as Exhibit 3.2 to this Annual Report on Form 10-K and incorporated herein by reference. The terms of the Warrants are reflected in the Form of Warrant to Purchase Common Units filed as Exhibit 4.28 to this Annual Report on Form 10-K, which is incorporated herein by reference.

At the closing, pursuant to a Board Representation and Observation Rights Agreement, the Preferred Purchasers received certain board appointment and observation rights and appointed one director and one observer to the Board of Directors of GP Natural Resource Partners LLC. For more information on these rights, see "Certain Relationships and Related Transactions, and Director Independence—Board Representation and Observation Rights Agreement."

We also entered into a registration rights agreement (the "Preferred Unit and Warrant Registration Rights Agreement") with the Preferred Purchasers, pursuant to which we are required to file (i) a shelf registration statement to register the common units issuable upon exercise of the Warrants and to cause such registration statement to become effective not later than 90 days following the closing date and (ii) a shelf registration statement to register the common units issuable upon conversion of the Preferred Units and to cause such registration statement to become effective not later than the earlier of the fifth anniversary of the closing date or 90 days following the first issuance of any common units upon conversion of Preferred Units (the "Registration Deadlines"). In addition, the Preferred Unit and Warrant Registration Rights Agreement gives the Preferred Purchasers piggyback registration and demand underwritten offering rights under certain circumstances. If the shelf registration statements are not effective by the applicable Registration Deadline, we will be required to pay the Preferred Purchasers liquidated damages in the amounts and upon the term set forth in the Preferred Unit and Warrant Registration Rights Agreement.

Opco Credit Facility Amendment

We entered into the Second Amendment to Opco’s Third Amended and Restated Credit Agreement to extend the term thereof until April 2020, and reduced the commitments of the lenders to $180 million (from $210 million) effective at the closing of the recapitalization transactions. Pursuant the Second Amendment, commitments under the Opco Credit Facility will be reduced to $150 million at December 31, 2017 and further reduced to $100 million at December 31, 2018 through maturity in April 2020. The amendment does not change the pricing grid or financial covenants under the Opco Credit Facility; provided, however, that if we increase our quarterly distribution to our common unitholders above $0.45 per common unit, the maximum leverage ratio under the Opco Credit Facility will permanently decrease from 4.0x to 3.0x. Other terms of the Second Amendment include revisions to the mandatory prepayment provisions with respect to net cash proceeds received from certain asset sales, additional limitations on the ability of Opco and its subsidiaries to make certain investments. The Second Amendment is filed as Exhibit 10.14 to this Annual Report on

Form 10-K and is incorporated herein by reference.

Issuance of 2022 Notes; Exchange and Redemption of 2018 Notes

NRP and NRP Finance issued $346 million aggregate principal amount of 10.500% Senior Notes due 2022 to several holders of its 2018 Notes. Of the $346 million of 2022 Notes issued, $241 million in aggregate principal amount were issued in exchange for $241 million in aggregate principal amount of 2018 Notes, and $105 million of the 2022 Notes were issued to the holders in exchange for cash. The 2022 Notes are issued under an Indenture dated as of March 2, 2017 (the "2022 Indenture"), bear interest at 10.500% per year, are payable semi-annually on March 15 and September 15, beginning September 15, 2017, and mature on March 15, 2022.

We and NRP Finance have the option to redeem the 2022 Notes, in whole or in part, at any time on or after March 15, 2019, at the redemption prices (expressed as percentages of principal amount) of 105.25% for the 12-month period beginning March 15, 2019, 102.625% for the 12-month period beginning March 15, 2020, and thereafter at 100.000%, together, in each case, with any accrued and unpaid interest to the date of redemption. Furthermore, before March 15, 2019, we may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net proceeds of certain public or private equity offerings at a redemption price of 110.500% of the principal amount of 2022 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 2022 Notes issued under the 2022 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 2022 Indenture, the holders of the 2022 Notes may require us to purchase their 2022 Notes at a purchase price equal to 101% of the principal amount of the 2022 Notes, plus accrued and unpaid interest, if any. The 2022 Notes purchased for cash were issued at a price of 98.75% (original issue discount of 1.25%), and each holder exchanging 2018 Notes received a fee of 5.813% of the aggregate principal amount of all 2018 Notes tendered for exchange by such holder, as well as all accrued and unpaid interest thereon.

The 2022 Indenture contains restrictive covenants that are substantially similar to those contained in the Indenture governing the 2018 Notes, except that the debt incurrence and restricted payments covenants contain additional restrictions. Under the debt incurrence covenant, our non-guarantor restricted subsidiaries will not be permitted to incur additional indebtedness unless their consolidated leverage ratio is less than 3.00x (measured on a pro forma basis and assuming that the greater of (i) $150.0 million of debt (or, if less, at our election, the amount of total lending commitments under any revolving credit facility) and (ii) the actual amount of debt outstanding is outstanding under any revolving credit facility); provided, however, that such non-guarantor restricted subsidiaries will be permitted to make up to $150 million in borrowings under a revolving credit facility (which amount will be reduced on a dollar-for-dollar basis to the extent we have made the election described in clause (i) above). Under the restricted payments covenant, we will not be able to increase the quarterly distribution on our common units or elect to pay more than 50% of the distributions required to be made on the Preferred Units in the form of cash, unless, in each case, our consolidated leverage ratio is less than 4.00x. The 2022 Indenture also contains restrictions on our ability to redeem the Preferred Units in cash.

The 2022 Notes are the senior unsecured obligations of NRP and NRP Finance. The 2022 Notes rank equal in right of payment to all existing and future senior unsecured debt of NRP and NRP Finance, including the remaining outstanding 2018 Notes, and senior in right of payment to any of our subordinated debt. The 2022 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 are structurally subordinated in right of payment to all existing and future debt and other liabilities of our subsidiaries, including the Opco Credit Facility and each series of Opco's existing senior notes. None of our subsidiaries guarantee the 2022 Notes.

The terms of the 2022 Notes are more fully described in the 2022 Indenture, which is filed as Exhibit 4.24 to this Annual Report on Form 10-K and incorporated herein by reference.

We entered into a registration rights agreement (the "Notes Registration Rights Agreement") with the holders of the 2022 Notes, pursuant to which we and NRP Finance agreed to file a registration statement with the Securities and Exchange Commission for the benefit of the holders of the 2022 Notes so that such holders can exchange the 2022 Notes for exchange securities that have substantially identical terms as the 2022 Notes. We and NRP Finance agreed to use commercially reasonable efforts to cause the exchange to be completed within 180 days after the closing and will be required to pay additional interest, as specified in the Notes Registration Rights Agreement, if we fail to comply with our obligations to register the 2022 Notes within the specified time periods.

We expect to redeem $90 million in aggregate principal amount of the 2018 Notes at a redemption price of 104.563%, and pay all accrued and unpaid interest thereon, in April 2017. In addition, we are required to redeem any and all remaining outstanding 2018 Notes (and pay all accrued and unpaid interest thereon) within 60 days after October 1, 2017.

The following table summarizes our long-term debt and convertible preferred unit obligations at December 31, 2016 and at December 31, 2016 after giving pro forma effect to the recapitalization transactions described above (in millions):

	Payments Due by Period						
As of December 31, 2016	2017	2018	2019	2020	2021	Thereafter	Total
2018 Notes	$—	$425.0	$—	$—	$—	$ —	$425.0
Opco Credit Facility	60.0	150.0	—	—	—	—	210.0
Opco Senior Notes and other	80.6	80.6	76.0	54.7	47.0	164.9	503.8
Total long-term debt obligations	$140.6	$655.6	$76.0	$54.7	$47.0	$ 164.9	$1,138.8

	Payments Due by Period						
After Recapitalization Transactions	2017	2018	2019	2020	2021	Thereafter	Total
2022 Notes	$—	$—	$—	$—	$—	$ 346.0	$346.0
2018 Notes	94.0	—	—	—	—	—	94.0
Opco Credit Facility(1)	—	—	—	—	—	—	—
Opco Senior Notes and other	80.6	80.6	76.0	54.7	47.0	164.9	503.8
Total long-term debt obligations	$174.6	$80.6	$76.0	$54.7	$47.0	$ 510.9	$943.8
Convertible preferred unit obligations	$—	$—	$—	$—	$—	$ 250.0	$250.0
Total long-term debt and convertible preferred unit obligations	$174.6	$80.6	$76.0	$54.7	$47.0	$ 760.9	$1,193.8

(1) Assumes no additional borrowings under the Opco Credit Facility following closing.

Current Liquidity

Generally, we satisfy our working capital requirements with cash generated from operations. Our current liabilities exceeded our current assets by approximately $83.8 million as of December 31, 2016, primarily due to $80.6 million in total principal payments due in 2017 on the Opco Senior Notes and Opco utility local improvement obligation and $60.0 million of payments due in 2017 on the Opco Credit Facility. Excluding these principal payments, our current assets exceeded our current liabilities by approximately $56.8 million as of December 31, 2016. In March 2017, we increased our liquidity through the completion of the recapitalization transactions described above. In addition to enhancing our liquidity, these recapitalization transactions reduced our 2018 debt maturities by $575 million through the extension of debt principal payments from 2018 to 2020 and 2022.

Capital Expenditures

A portion of the capital expenditures associated with our VantaCore segment are maintenance capital expenditures, which are capital expenditures made to maintain the long-term production capacity of those businesses. Expansion capital expenditures are made to increase productive capacity. We deduct maintenance capital expenditures when calculating DCF. VantaCore's maintenance and expansion capital expenditures for the year ended December 31, 2016 were $4.4 million and $1.0 million, respectively.

Cash Flows

Cash flow provided by operating activities decreased $95.4 million, from $203.4 million in the year ended December 31, 2015 to $108.0 million in the year ended December 31, 2016. Operating cash flow from continuing operations decreased $70.4 million in our Coal Royalty and Other segment year-over-year primarily as a result of the reduction in coal royalty revenue and reduction of coal royalty minimum cash payments received on certain leases. Cash flow provided by operating activities of discontinued operations decreased $27.6 million, from $34.9 million in the year ended December 31, 2015 to $7.3 million in the year ended December 31, 2016 primarily as a result of completing the sale of our non-operated oil and gas working interest assets in July 2016 that had an effective date of April 1, 2016.

Cash flow provided by operating activities decreased $7.4 million, from $210.8 million in the year ended December 31, 2014 to $203.4 million in the year ended December 31, 2015. Operating cash flow from continuing operations decreased $33.7 million in our Coal Royalty and Other segment year-over-year primarily as a result of the reduction in coal royalty revenue and reduction of coal royalty minimum cash payments received on certain leases. Corporate and Financing used an additional $11.4 million in operating activities of continuing operations primarily due to the increase in cash paid for interest year-over-year. These decreases were partially offset by a $20.9 million increase in cash provided by operating activities of continuing operations in our VantaCore segment primarily due to a full year of operations due to the fourth quarter of 2014 acquisition. Cash flow provided by operating activities of discontinued operations increased $16.3 million, from $18.6 million in the year ended December 31, 2014 to $34.9 million in the year ended December 31, 2015 primarily as a result of a full year of revenue on our fourth quarter 2014 Williston Basin non-operated working interest asset acquisition.

Cash flow provided by investing activities increased $197.1 million, from $30.3 million used in the year ended December 31, 2015 to $166.8 million provided in the year ended December 31, 2016. Investing cash flows from discontinued operations increased $144.2 million primarily as a result of the sale of our non-operated oil and gas working interest assets in July 2016 for $109.9 million in net cash proceeds in addition to a $37.8 million decrease in cash flow used as a result of lower oil and gas drilling activity and the non-operated working interest asset sale in July 2016. Investing cash flows from continuing operations increased $52.9 million primarily as a result of 2016 sales of oil and gas and aggregate royalty properties.

Cash flow used by investing activities decreased $490.2 million, from $520.5 million in the year ended December 31, 2014 to $30.3 million in the year ended December 31, 2015 primarily due to the 2014 VantaCore acquisition and various 2015 asset sales including an aggregate preparation plant, cell phone tower lease contracts and condemnation payments within our Coal Royalty and Other segment, partially offset by plant and equipment acquisitions within our VantaCore segment. Cash flow used by investing activities of discontinued operations decreased $313.7 million primarily due to our 2014 investing activities consisting of our Sanish Field acquisition as well as additional capital expenditures related to the participation in new wells, partially offset by 2015 well participation costs.

Cash flow used in financing activities increased $114.7 million, from $171.5 million in the year ended December 31, 2015 to $286.2 million in the year ended December 31, 2016. Cash used in financing activities of discontinued operations increased $136.6 million primarily as a result of using $85.0 million to repay the RBL Credit Facility and contributing the $39.4 million of discontinued asset sales proceeds that remained after repayment of the RBL Facility in full to continuing operations. This increase in cash flow used in financing activities was partially offset by a $21.9 million decrease in cash flow used in financing activities from continuing operations primarily a result of distributing $49.3 million less cash to partners and receiving the remaining net proceeds from discontinuing operations after repayment as described above.

Cash flow used in financing activities increased $438.8 million, from $267.3 million provided in the year ended December 31, 2014 to $171.5 million used in the year ended December 31, 2015 primarily due to $518.4 million in loan proceeds and $127.2 million in general partner contributions received during the year ended December 31, 2014. This change was partially offset by higher distributions to partners and loan repayments made during 2014. Cash flow provided by financing activities of discontinued operations decreased $321.5 million, from $333.3 million in the year ended December 31, 2014 to $11.8 million provided in the year ended December 31, 2015, primarily as a result of contributions from continuing operations to fund investing activities of the discontinued operation in 2014.

Capital Resources and Obligations

Indebtedness

As of December 31, 2016 and 2015, we had the following indebtedness (in thousands):

	December 31, 2016	December 31, 2015
Current portion of long-term debt, net	$138,903	$80,745
Long-term debt and debt—affiliate, net	987,400	1,290,211
Total debt and debt—affiliate, net	$1,126,303	$1,370,956

We were and continue to be in compliance with the terms of the financial covenants contained in Opco's debt agreements. Adjusted EBITDA as defined in "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Adjusted EBITDA" differs from the EBITDDA definitions contained in our debt agreements. For additional information regarding our debt and the agreements governing our debt, including the covenants contained therein, see and "—2017 Recapitalization Transactions" above and "Item 8. Financial Statements and Supplementary Data—Note 11. Debt and Debt—Affiliate" in this Annual Report on Form 10-K.

Long-Term Contractual Obligations

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2016 (in millions):

	Payments Due by Period						
Contractual Obligations	Total	2017	2018	2019	2020	2021	Thereafter
NRP:							
Long-term debt principal payments (including current maturities) (1)	$425.0	$—	$425.0	$—	$—	$—	$ —
Long-term debt interest payments (1)	77.6	38.8	38.8	—	—	—	—
Opco:							
Long-term debt principal payments (including current maturities) (2)	713.8	140.6	230.6	76.0	54.7	47.0	164.9
Long-term debt interest payments (3)	114.8	28.1	23.1	18.1	14.2	11.1	20.2
Rental leases (4)	5.2	2.2	1.6	0.1	0.1	0.1	1.1
Total	$1,336.4	$209.7	$719.1	$94.2	$69.0	$58.2	$ 186.2

(1) The amounts indicated in the table include principal and interest due on NRP’s 2018 Notes.
(2) The amounts indicated in the table include principal due on Opco’s senior notes, credit facility and utility local improvement obligation.
(3) The amounts indicated in the table include interest due on Opco’s senior notes and utility local improvement obligation.
(4) The rental lease amounts primarily consist of office space and VantaCore equipment leases.

Shelf Registration Statement

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

Off-Balance Sheet Transactions

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

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, 2016, 2015 and 2014.

Environmental Regulation

For additional information on environmental regulation that may have a material impact on our business, see "Item 1. Business and Properties—Regulation and Environmental Matters."

Related Party Transactions

The information required by this Item is included under "Item 8. Financial Statements and Supplementary Data—Note 13. Related Party Transactions" and "Item 13. Certain Relationships and Related Transactions, and Director Independence" in this Annual Report on Form 10-K and is incorporated by reference herein.

Summary of Critical Accounting 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. See "Note 2. Summary of Significant Accounting Policies" to the audited consolidated financial statements under Item 8 of this Form 10-K for discussion of our significant accounting policies. The following critical accounting policies are affected by estimates and assumptions used in the preparation of Consolidated Financial Statements.

Revenues

Coal Royalty and Other Revenues. Coal royalty and other 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. Other revenues include transportation and processing fees. 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.

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 a deferred revenue liability 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.

Oil and gas related revenues consist of revenues from royalties and overriding royalties. Oil and gas royalty revenues are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales.

Equity in Earnings from Ciner Wyoming. We account for non-marketable equity 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 Ciner 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 investee's net assets is hypothetically allocated first to identified tangible assets and liabilities, then to finite-lived intangibles or indefinite-lived intangibles and the remaining 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." Our share of 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 net assets, 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.

VantaCore Revenues. 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. 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.

Mineral Rights

Mineral rights owned and leased are recorded at its original cost of construction or, upon acquisition, at fair value of the assets acquired. 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 as defined by the SEC’s Industry Guide 7 and estimated by our internal reserve engineers. The technologies and economic data used by our internal reserve engineers in the estimation of our proved reserves include, but are not limited to, drill logs, geophysical logs, geologic maps including isopach, mine, and coal quality, cross sections, statistical analysis, and available public production data. 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.

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. We believe our estimates of cash flows and discount rates are consistent with those of principal market participants. 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.

We evaluate our equity investment 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.

Recent Accounting Standards

For a discussion of recent accounting pronouncements, see the applicable section of "Item 8. Financial Statements and Supplementary Data—Note 2. Summary of Significant Accounting Policies" to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

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 as discussed below:

Commodity Price Risk

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

We have market risk related to prices for our aggregates products. Aggregates prices are primarily driven by economic conditions in the local markets in which the products are sold.
The market price of soda ash directly affects the profitability of Ciner Wyoming's operations. If the market price for soda ash declines, Ciner Wyoming's sales will decrease. Historically, the global market and, to a lesser extent, the domestic market for soda ash have been volatile, and those markets are likely to remain volatile in the future.

Interest Rate Risk

Our exposure to changes in interest rates results from our borrowings under the Opco Credit Facility, which is subject to variable interest rates based upon LIBOR. At December 31, 2016, we had $210.0 million outstanding in variable interest rate debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $2.1 million, assuming the same principal amount remained outstanding during the year.

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, 2016 and 2015, and the related consolidated statements of comprehensive income (loss), partners' capital and cash flows for each of the three years in the period ended December 31, 2016. 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 Ciner Wyoming LLC (Ciner Wyoming), a Limited Liability Company in which Natural Resource Partners L.P. owns a 49% interest. In the consolidated financial statements Natural Resource Partners L.P.'s investment in Ciner Wyoming is stated at $256 million and $262 million as of December 31, 2016 and 2015 respectively, and Natural Resource Partners L.P.'s equity in the net income of Ciner Wyoming is stated at $40 million, $50 million, and $41 million for each of the three years in the period ended December 31, 2016. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Ciner Wyoming LLC, is based 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 the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Natural Resource Partners L.P. at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, 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, 2016, 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 March 6, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 6, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Managers and Members of
Ciner Wyoming LLC
Atlanta, Georgia

We have audited the accompanying balance sheets of Ciner Wyoming LLC (the "Company") as of December 31, 2016 and 2015 and the related statements of operations and comprehensive income, members' equity, and cash flows for each of the three years in the period ended December 31, 2016. 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) and in accordance with auditing standards generally accepted in the United States of America. 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, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia
March 6, 2017

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

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$40,371	$41,204
Accounts receivable, net	43,202	43,633
Accounts receivable—affiliates, net	6,658	6,345
Inventory	6,893	7,835
Prepaid expenses and other	6,137	4,268
Current assets of discontinued operations (see Note 3)	991	17,844
Total current assets	104,252	121,129
Land	25,252	25,022
Plant and equipment, net	49,443	60,675
Mineral rights, net	908,192	984,522
Intangible assets, net	3,236	3,930
Intangible assets, net—affiliate	49,811	52,997
Equity in unconsolidated investment	255,901	261,942
Long-term contracts receivable—affiliate	43,785	47,359
Other assets	3,791	1,173
Other assets—affiliate	1,018	1,124
Non-current assets of discontinued operations (see Note 3)	—	110,162
Total assets	$1,444,681	$1,670,035
LIABILITIES AND CAPITAL		
Current liabilities:		
Accounts payable	$6,234	$5,022
Accounts payable—affiliates	940	801
Accrued liabilities	41,587	44,997
Accrued liabilities—affiliates	—	456
Current portion of long-term debt, net	138,903	80,745
Current liabilities of discontinued operations (see Note 3)	353	4,388
Total current liabilities	188,017	136,409
Deferred revenue	44,931	80,812
Deferred revenue—affiliates	71,632	82,853
Long-term debt, net	987,400	1,186,681
Long-term debt, net—affiliate	—	19,930
Other non-current liabilities	4,565	5,171
Non-current liabilities of discontinued operations (see Note 3)	—	85,237
Commitments and contingencies (see Note 14)		
Partners' capital:		
Common unitholders' interest (12,232,006 units outstanding)	152,309	79,094
General partner's interest	887	(606)
Accumulated other comprehensive loss	(1,666)	(2,152)
Total partners' capital	151,530	76,336
Non-controlling interest	(3,394)	(3,394)
Total capital	148,136	72,942

Total liabilities and capital	$1,444,681	$1,670,035

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

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

	For the Years Ended December 31, 2016	2015	2014
Revenues and other income:			
Coal royalty and other	$144,520	$154,066	$181,526
Coal royalty and other—affiliates	65,595	89,715	84,559
VantaCore	120,802	139,049	42,031
Equity in earnings of Ciner Wyoming	40,061	49,918	41,416
Gain on asset sales, net	29,081	6,900	1,386
Total revenues and other income	400,059	439,648	350,918
Operating expenses:			
Operating and maintenance expenses	119,621	136,943	65,933
Operating and maintenance expenses—affiliates, net	10,925	15,323	10,197
Depreciation, depletion and amortization	43,087	57,295	58,586
Amortization expense—affiliate	3,185	3,621	3,308
General and administrative	16,979	7,036	7,287
General and administrative—affiliates	3,591	5,312	3,258
Asset impairments	16,926	384,545	26,209
Total operating expenses	214,314	610,075	174,778
Income (loss) from operations	185,745	(170,427)	176,140
Other income (expense)			
Interest expense	(90,047)	(87,911)	(79,144)
Interest expense—affiliate	(523)	(1,851)	(379)
Interest income	39	18	96
Other expense, net	(90,531)	(89,744)	(79,427)
Net income (loss) from continuing operations	95,214	(260,171)	96,713
Income (loss) from discontinued operations (see Note 3)	1,678	(311,549)	12,117
Net income (loss)	$96,892	$(571,720)	$108,830
Net income (loss) attributable to limited partners:			
Continuing operations	$93,585	$(254,173)	$94,779
Discontinued operations	1,644	(305,319)	11,874
Total	$95,229	$(559,492)	$106,653
Net income (loss) attributable to the general partner:			
Continuing operations	$1,629	$(5,998)	$1,934
Discontinued operations	34	(6,230)	243
Total	$1,663	$(12,228)	$2,177
Basic and diluted net income (loss) per common unit:			
Continuing operations	$7.65	$(20.78)	$8.37

Discontinued operations	0.13	(24.97)	1.05
Total	$7.78	$(45.75)	$9.42
Average number of common units outstanding	12,232	12,232	11,326
Net income (loss)	$96,892	$(571,720)	$108,830
Add: comprehensive income (loss) from unconsolidated investment and other	486	(1,693)	(81)
Comprehensive income (loss)	$97,378	$(573,413)	$108,749

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

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

	Common Unitholders Units	Common Unitholders Amounts	General Partner	Accumulated Other Comprehensive Income (Loss)	Partners' Capital Excluding Non-Controlling Interest	Non-Controlling Interest	Total Capital
Balance at December 31, 2013	10,983	$606,774	$10,069	$ (378)	$ 616,465	$ 324	$616,789
Net income	—	106,653	2,177	—	108,830	—	108,830
Issuance of common units	1,006	127,202	—	—	127,202	—	127,202
Issuance of common units for acquisitions	243	31,604	—	—	31,604	—	31,604
Capital contribution	—	—	3,240	—	3,240	—	3,240
Cost associated with equity transactions	—	(4,413)	—	—	(4,413)	—	(4,413)
Distributions to unitholders	—	(158,801)	(3,241)	—	(162,042)	—	(162,042)
Distributions to non-controlling interests	—	—	—	—	—	(974)	(974)
Comprehensive loss from unconsolidated investment and other	—	—	—	(81)	(81)	—	(81)
Balance at December 31, 2014	12,232	$709,019	$12,245	$ (459)	$ 720,805	$ (650)	$720,155
Net loss	—	(559,492)	(12,228)	—	(571,720)	—	(571,720)
Cost associated with equity transactions	—	(109)	—	—	(109)	—	(109)
Distributions to unitholders	—	(70,324)	(1,434)	—	(71,758)	—	(71,758)
Distributions to non-controlling interests	—	—	—	—	—	(2,744)	(2,744)
Non-cash contributions	—	—	811	—	811	—	811
Comprehensive loss from unconsolidated investment and other	—	—	—	(1,693)	(1,693)	—	(1,693)
Balance at December 31, 2015	12,232	$79,094	$(606)	$ (2,152)	$ 76,336	$ (3,394)	$72,942
Net income	—	95,229	1,663	—	96,892	—	96,892
Distributions to unitholders	—	(22,014)	(451)	—	(22,465)	—	(22,465)
Non-cash contributions	—	—	281	—	281	—	281
Comprehensive income from unconsolidated investment and other	—	—	—	486	486	—	486
Balance at December 30, 2016	12,232	$152,309	$887	$ (1,666)	$ 151,530	$ (3,394)	$148,136

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

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

	For the Years Ended December 31,		
	2016	2015	2014
Cash flows from operating activities:			
Net income (loss)	$96,892	$(571,720)	$108,830
Adjustments to reconcile net income to net cash provided by operating activities of continuing operations:			
Depreciation, depletion and amortization	43,087	57,295	58,586
Amortization expense—affiliates	3,185	3,621	3,308
Distributions from equity earnings from unconsolidated investment	46,550	46,795	43,005
Equity earnings from unconsolidated investment	(40,061)	(49,918)	(41,416)
Gain on asset sales, net	(29,081)	(6,900)	(1,386)
(Income) loss from discontinued operations	(1,678)	311,549	(12,117)
Asset impairments	16,926	384,545	26,209
Gain on reserve swap	—	(9,290)	(5,690)
Other, net	8,284	(7,109)	(5,279)
Other, net—affiliates	993	(912)	(180)
Change in operating assets and liabilities:			
Accounts receivable	431	7,705	4,483
Accounts receivable—affiliates	(313)	3,149	(1,828)
Accounts payable	707	(3,625)	(8,928)
Accounts payable—affiliates	139	(32)	457
Accrued liabilities	4,618	1,420	6,002
Accrued liabilities—affiliates	(456)	—	456
Deferred revenue	(35,881)	7,605	2,056
Deferred revenue—affiliates	(11,222)	(4,200)	15,618
Other items, net	(2,477)	(1,466)	(22)
Other items, net—affiliates	—	—	—
Net cash provided by operating activities of continuing operations	100,643	168,512	192,164
Net cash provided by operating activities of discontinued operations	7,318	34,912	18,591
Net cash provided by operating activities	107,961	203,424	210,755
Cash flows from investing activities:			
Proceeds from sale of oil and gas royalty properties	42,844	—	—
Proceeds from sale of coal and aggregate royalty properties	18,189	3,505	412
Return of long-term contract receivables—affiliate	2,968	2,463	1,904
Proceeds from sale of plant and equipment and other	1,350	11,024	1,006
Acquisition of plant and equipment and other	(5,408)	(9,607)	(2,454)
Acquisition of mineral rights	—	(400)	(5,035)
Acquisition of aggregates business	—	—	(168,978)
Return of equity from unconsolidated investment	—	—	3,633
Net cash provided by (used in) investing activities of continuing operations	59,943	6,985	(169,512)
Net cash provided by (used in) investing activities of discontinued operations	106,872	(37,256)	(350,991)
Net cash provided by (used in) investing activities	166,815	(30,271)	(520,503)

Cash flows from financing activities:			
Proceeds from loans	20,000	100,000	498,471
Proceeds from loan—affiliate	—	—	19,904
Proceeds from issuance of common units	—	—	127,202
Capital contribution by general partner	—	—	3,240
Repayments of loans	(183,141)	(165,983)	(318,983)

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

Distributions to unitholders	(22,465)	(71,758)	(162,042)
Distributions to non-controlling interest	—	(2,744)	(974)
Contributions from (to) discontinued operations	39,421	(36,725)	(226,000)
Debt issue costs and other	(15,234)	(6,054)	(6,804)
Net cash used in financing activities of continuing operations	(161,419)	(183,264)	(65,986)
Net cash provided by (used in) financing activities of discontinued operations	(124,759)	11,808	333,297
Net cash provided by (used in) financing activities	(286,178)	(171,456)	267,311
Net increase (decrease) in cash and cash equivalents	(11,402)	1,697	(42,437)
Cash and cash equivalents of continuing operations at beginning of period	41,204	48,971	92,305
Cash and cash equivalents of discontinued operations at beginning of period	10,569	1,105	208
Cash and cash equivalents at beginning of period	51,773	50,076	92,513
Cash and cash equivalents at end of period	40,371	51,773	50,076
Less: cash and cash equivalents of discontinued operations at end of period	—	10,569	1,105
Cash and cash equivalents of continuing operations at end of period	$40,371	$41,204	$48,971
Supplemental cash flow information:			
Cash paid during the period for interest	$84,380	$85,738	$75,833
Non-cash investing activities:			
Plant, equipment and mineral rights funded with accounts payable or accrued liabilities	$—	$4,304	$—
Units issued for acquisition of aggregates business	$—	$—	$31,604

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

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NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Nature of Operations

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, operating, managing and leasing a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, construction aggregates and other natural resources and is organized into three operating segments further described in Note 4. Segment Information. As used in these Notes to Consolidated Financial Statements, the terms "NRP," "we," "us" and "our" refer to Natural Resource Partners L.P. and its subsidiaries, unless otherwise stated or indicated by context.

The Partnership's operations are conducted through, and its operating assets are owned by, its subsidiaries. The Partnership owns its subsidiaries through one wholly owned operating company, NRP (Operating) LLC ("Opco"). NRP GP has sole responsibility for conducting the Partnership's 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 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

Basis of Presentation

The accompanying Consolidated Financial Statements of the Partnership have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP"). The consolidated financial statements include the accounts of Natural Resource Partners L.P. and its wholly owned subsidiaries, as well as BRP LLC ("BRP"), a joint venture with International Paper Company controlled by the Partnership. The Partnership has an equity investment through which it is able to exercise significant influence over but does not control the investee and is not the primary beneficiary of the investee's activities which is accounted for using the equity method. Intercompany transactions and balances have been eliminated.

Management's Going Concern Analysis

While NRP has a diversified portfolio of assets and a history and continued forecast of profitable operations with positive operating cash flows, its operating results and credit metrics have been impacted by challenges in coal and other commodity markets. The following going concern analysis includes discussion of the relevant conditions and events and an evaluation of NRP's ability to meet its obligations and remain in compliance with its debt covenants within one year after the issuance date of these financial statements.

In order to mitigate the effect of these adverse market developments on the Partnership's ability to remain in compliance with the covenants under its debt agreements and meet scheduled debt principal payments, the Partnership pursued or considered a number of actions. On a cumulative basis since January 1, 2015, the Partnership reduced debt by $339.1 million and completed asset sales for $199 million in gross sales proceeds. In addition, the Partnership completed the following series of recapitalization transactions on March 2, 2017 (see Note 19. Subsequent Events for further detail):

- the issuance of $250 million of a new class of 12.0% preferred units representing limited partner interests in NRP, together with warrants to purchase common units, to certain entities controlled by funds affiliated with The Blackstone Group, L.P. (collectively referred to as "Blackstone") and certain affiliates of GoldenTree Asset Management LP (collectively referred to as "GoldenTree");
- the exchange of $241 million of our 9.125% Senior Notes due 2018 (the "2018 Notes") for $241 million of a new series of 10.500% Senior Notes due 2022 (the "2022 Notes"), and the sale of $105 million of additional 2022 Notes in exchange for cash proceeds; and
- the extension of Opco's revolving credit facility (the "Opco Credit Facility") to April 2020, with commitments thereunder reduced to $180 million.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

These recapitalization transactions increased the Partnership's liquidity and reduced the Partnership's 2018 debt maturities by $575 million through the extension of debt principal payments from 2018 to 2020 and 2022. While the Partnership continues to face challenges in coal and other commodity markets, it expects that it will meet all of its obligations, including scheduled principal and interest payments on its debt and required distributions on the convertible preferred units, that it will remain in compliance with its debt covenants and that it will continue as a going concern.

Recasting of Certain Prior Period Information

As described in Note 3. Discontinued Operations, the Partnership has classified the assets and liabilities, operating results and cash flows of its non-operated oil and gas working interest assets as discontinued operations in its consolidated financial statements for all periods presented. As described in Note 4. Segment Information, the Partnership has reclassified oil and gas royalty activities in prior period amounts to conform to the way it internally manages and monitors segment performance that had no impact on the Partnership's consolidated financial position, net income (loss) or cash flows.

On January 1, 2016, the Partnership adopted a new accounting standard using a retrospective approach that required the presentation of the Partnership's debt issuance costs as a direct deduction from the related debt liability, rather than recorded as an asset. The adoption resulted in a reclassification that reduced other current assets and short-term debt by $0.2 million and reduced other assets and long-term debt (including affiliate) by $13.8 million on the Partnership’s Consolidated Balance Sheet at December 31, 2015.

Reverse Unit Split

On January 26, 2016, the board of directors of our general partner approved a 1-for-10 reverse split on our common units, effective following market close on February 17, 2016. Pursuant to the authorization provided, the Partnership completed the 1-for-10 reverse unit split and its common units began trading on a reverse unit split-adjusted basis on the New York Stock Exchange on February 18, 2016. As a result of the reverse unit split, every 10 outstanding common units were combined into one common unit. The reverse unit split reduced the number of common units outstanding from 122.3 million units to approximately 12.2 million units. All units and per unit data included in the December 31, 2015 consolidated financial statements were retroactively restated to reflect the reverse unit split.

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.

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.

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 12. 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.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

- 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. The reserve is recognized as a reduction in the accounts receivable and an increase in operating and maintenance expenses or operating and maintenance expenses—affiliates. Accounts are charged off when collection efforts are complete and future recovery is doubtful. The allowance for doubtful accounts included in the Partnership's net accounts receivable balance (including affiliates) was $4.6 million and $5.3 million at December 31, 2016 and December 31, 2015, respectively. A significant amount of the Partnership's allowance for doubtful accounts relates to allowances for doubtful coal-related receivables.

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 is recorded at its original cost of construction or, upon acquisition, at fair value of the asset acquired and 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

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 recorded at its original cost of construction or, upon acquisition, at fair value of the assets acquired. 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.

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.

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. The Partnership believes its estimates of cash flows and discount rates are consistent with those of principal market participants. 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.

The Partnership evaluates its equity investment 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.

Revenue Recognition

Coal Royalty and Other Revenues. Coal royalty and other 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. Other revenues include transportation and processing fees. 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.

Most of the Partnership's coal and aggregates lessees must pay the Partnership minimum annual or quarterly amounts which are generally recoupable out of actual production over certain time periods. These minimum payments are recorded as deferred revenue liability 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.

Oil and gas related revenues consist of revenues from royalties and overriding royalties. 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.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Equity in Earnings from Ciner Wyoming. The Partnership accounts for non-marketable equity 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 the Partnership has an ownership interest representing between 20% and 50% of the voting stock of the investee. The Partnership accounts for its investment in Ciner 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 investee's net assets 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 Ciner Wyoming is reflected in the caption "Equity in unconsolidated investments" in our Consolidated Balance Sheets. Our adjusted share of the earnings or losses of Ciner Wyoming is reflected in the Consolidated Statements of Comprehensive Income as revenues and other income under the caption ‘‘Equity in earnings of Ciner Wyoming." Our share of 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 net assets, 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.

VantaCore Revenues. 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. 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 Coal Royalty and Other revenues and in Operating and maintenance expenses, respectively, in the Consolidated Statements of Comprehensive Income.

Transportation Revenue and Expense

The Company records transportation revenue and pays transportation costs to a Foresight affiliate to operate equipment on behalf of the Company. The revenue and expenses related to these transactions are recorded as Coal Royalty and Other—affiliates revenues and Operating and maintenance expenses—affiliates in the Consolidated Statements of Comprehensive Income. Shipping and handling costs invoiced to aggregate customers and paid to third-party carriers are recorded as VantaCore revenues and Operating and maintenance expenses in the Consolidated Statements of Comprehensive Income. Shipping and handling revenue included in VantaCore revenues was $36.0 million, $42.6 million and $14.0 million for the years ended December 31, 2016, 2015 and 2014, respectively. Shipping and handling costs included in Operating and maintenance expenses was $35.9 million, $42.1 million and $13.9 million for the years ended December 31, 2016, 2015, and 2014, respectively.

Unit-Based Compensation

The Partnership has awarded unit-based compensation in the form of phantom units that are more fully described in Note 16. Unit-Based Compensation. A summary of our accounting policy for unit-based awards follows.

The Partnership accounts for awards relating to its unit-based 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 requisite service 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.

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. Deferred financing costs for existing debt agreements are included as a a direct deduction from the related debt liability on the Partnership's Consolidated Balance Sheets. Deferred financing costs that the Partnership has incurred related to its restructuring efforts are included in Other Assets on the Partnership's Consolidated Balance Sheets until the related debt agreement has been executed.

Income Taxes

The Partnership is not subject to federal or material state income taxes, as the partners are taxed individually on their allocable share of taxable income. 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.

Recently Issued Accounting Standards

The Financial Accounting Standards Board ("FASB") issued guidance that requires an entity's management to evaluate, for each reporting period, whether there are conditions and events that raise substantial doubt about the entity's ability to continue as a going concern within one year after the financial statements are issued. Additional disclosures are required if management concludes that conditions or events raise substantial doubt about the entity's ability to continue as a going concern. The Partnership adopted this guidance on December 31, 2016. For additional information, see Management's Going Concern Analysis located in this footnote above.

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NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The FASB issued authoritative guidance on revenue recognition. The core principle of this guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance will also require enhanced disclosures, provide more comprehensive guidance for transactions such as service revenue and contract modifications, and enhance guidance for multiple-element arrangements. The Partnership is required to adopt this guidance in the first quarter of 2018 using one of two retrospective application methods. The Partnership has performed revenue scoping procedures to identify the contracts for all of its revenue streams and utilized the practical expedient of grouping contracts or performance obligations with similar characteristics as prescribed by the new standard. The Partnership is currently evaluating these contracts and while the effect of adoption is unknown, it is not currently aware of any material changes that would result from adoption of this new revenue recognition guidance and expects to complete its assessment of how it will be affected in the second quarter of 2016. The Partnership anticipates utilizing the full retrospective adoption method for financial statement comparability and electing the practical expedient of not restating contracts that begin and are completed within the same annual reporting period.

The FASB issued authoritative guidance which intended to simplify the measurement of inventory. This guidance requires an entity to measure inventory at the lower of cost or net realizable value, and defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. This guidance is effective for annual and interim periods beginning after December 15, 2016. The Partnership does not expect for the adoption of this guidance to have a material impact on its consolidated financial statements.

The FASB issued authoritative lease guidance that requires lessees to recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The guidance also requires disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. The guidance is effective for annual and interim periods ending after December 31, 2018. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated financial statements.

The FASB issued authoritative guidance that replaces the incurred loss impairment methodology in the current standard with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. The guidance is effective for annual and interim periods ending after December 31, 2019. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated financial statements.

The FASB issued authoritative guidance to clarify how certain cash receipts and cash payments are presented and classified in the statement of cash flows in order to reduce current and potential future diversity in practice. The guidance is effective for annual and interim periods ending after December 31, 2017. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated financial statements.

3. Discontinued Operations

In June 2016, NRP Oil and Gas signed a definitive agreement to sell its non-operated oil and gas working interest assets assets for $116.1 million in gross sales proceeds, and the Partnership determined it met the criteria required for held for sale classification. In July 2016, NRP Oil and Gas closed this transaction, which had an effective date of April 1, 2016.

The Partnership's exit from its non-operated oil and gas working interest business represented a strategic shift to reduce debt and focus on its construction aggregates, soda ash and coal royalty and other business segments. As a result, the Partnership classified the operating results, cash flows and assets and liabilities of its non-operated oil and gas working interest assets as discontinued operations in its consolidated statements of comprehensive income and consolidated statements of cash flows for all periods presented. The Partnership transitioned the remaining investments in royalty interests in oil and natural gas properties into the Coal Royalty and Other operating segment during the third quarter of 2016.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The following table (in thousands) presents summarized financial results of the Partnership's discontinued operations in the Consolidated Statements of Comprehensive Income:

	For the Years Ended December 31,		
	2016	2015	2014
Revenues and other income:			
Oil and gas	$16,486	$48,750	$48,834
Gain on asset sales	8,274	451	—
Total revenues and other income	24,760	49,201	48,834
Operating expenses:			
Operating and maintenance expenses (including affiliates)	11,503	19,724	18,073
Depreciation, depletion and amortization	7,527	39,912	17,982
Asset impairments	564	297,049	—
Total operating expenses	19,594	356,685	36,055
Interest expense	(3,488)	(4,065)	(662)
Income (loss) from discontinued operations	$1,678	$(311,549)	$12,117

The following table (in thousands) presents the carrying amounts of the Partnership's assets and liabilities of discontinued operations in the Consolidated Balance Sheets:

	December 31,	
	2016	2015
ASSETS		
Current assets:		
Cash and cash equivalents	$—	$10,569
Accounts receivable, net (including affiliates) (1)	991	7,053
Other	—	222
Total current assets	991	17,844
Mineral rights, net	—	109,505
Other non-current assets	—	657
Total assets of discontinued operations	$991	$128,006
LIABILITIES		
Current liabilities:		
Other (including affiliates) (1)	$353	$4,388
Total current liabilities	353	4,388
Long-term debt, net (2)	—	83,600
Other non-current liabilities	—	1,637
Total liabilities of discontinued operations	$353	$89,625

(1) See Note 13. Related Party Transactions for additional information on the Partnership's related party assets and liabilities.
(2) The Partnership identified the RBL Facility as specifically attributed to its non-operated oil and gas working interest assets and included the interest from this debt in discontinued operations. See Note 11. Debt and

Debt—Affiliate for additional information on the Partnership's debt related to discontinued operations.

The following table (in thousands) presents supplemental cash flow information of the Partnership's discontinued operations:

	For the Years Ended December 31,		
	2016	2015	2014
Cash paid for interest	$1,906	$2,755	$ 322
Plant, equipment and mineral rights funded with accounts payable or accrued liabilities	—	1,645	11,879

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Capital expenditures related to the Partnership's discontinued operations were $1.4 million, $30.6 million and $359.9 million during the years months ended December 31, 2016, 2015 and 2014, respectively.

4. Segment Information

The Partnership's segments are strategic business units that offer products and services to different customer segments in different geographies within the U.S. and that are managed accordingly. NRP has the following three operating segments:

Coal Royalty and Other—consists primarily of coal royalty and coal related transportation and processing assets. Other assets include aggregate royalty, industrial mineral royalty, oil and gas royalty and timber. The Partnership's coal reserves are primarily located in Appalachia, the Illinois Basin and the Western United States. The Partnership's aggregates and industrial minerals are located in a number of states across the United States. The Partnership's oil and gas royalty assets are located in Louisiana.

Soda Ash—consists of the Partnership's 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. Ciner 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.

VantaCore—consists of the Partnership's construction materials business that operates hard rock quarries, an underground limestone mine, sand and gravel plants, asphalt plants and marine terminals. VantaCore operates in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

Direct segment costs and certain costs incurred at a corporate level that are identifiable and that benefit the Partnership's segments are allocated to the operating segments. These allocated costs include costs of: taxes, legal, information technology and shared facilities services and are included in Operating and maintenance expenses and Operating and maintenance expenses—affiliates on the Consolidated Statements of Comprehensive Income. Intersegment sales are at prices that approximate market.

Corporate and Financing includes functional corporate departments that do not earn revenues. Costs incurred by these departments include corporate headquarters and overhead, financing, centralized treasury and accounting and other corporate-level activity not specifically allocated to a segment.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The following table summarizes certain financial information for each of the Partnership's operating segments (in thousands):

	Operating Segments				
For the Year Ended	Coal Royalty and Other	Soda Ash	VantaCore	Corporate and Financing	Total
December 31, 2016					
Revenues (including affiliates)	$210,115	$40,061	$120,802	$ —	$370,978
Intersegment revenues (expenses)	150	—	(150)	—	—
Gain on asset sales	29,068	—	13	—	29,081
Operating and maintenance expenses (including affiliates)	29,890	—	100,656	—	130,546
General and administrative (including affiliates)	—	—	—	20,570	20,570
Depreciation, depletion and amortization (including affiliates)	31,766	—	14,506	—	46,272
Asset impairment	15,861	—	1,065	—	16,926
Other expense, net	—	—	—	90,531	90,531
Net income (loss) from continuing operations	161,816	40,061	4,438	(111,101)	95,214
Net income from discontinued operations	—	—	—	—	1,678
Capital expenditures	5	—	5,380	—	5,385
Total assets of continuing operations at December 31, 2016	990,172	255,901	190,615	7,002	1,443,690
Total assets of discontinued operations at December 31, 2016	—	—	—	—	991
December 31, 2015					
Revenues (including affiliates)	$243,781	$49,918	$139,049	$ —	$432,748
Intersegment revenues (expenses)	21	—	(21)	—	—
Gain (loss) on asset sales	6,936	—	(36)	—	6,900
Operating and maintenance expenses (including affiliates)	35,321	—	116,945	—	152,266
General and administrative (including affiliates)	—	—	—	12,348	12,348
Depreciation, depletion and amortization (including affiliates)	45,338	—	15,578	—	60,916
Asset impairment	378,327	—	6,218	—	384,545
Other expense, net	—	—	—	89,744	89,744
Net income (loss) from continuing operations	(208,248)	49,918	251	(102,092)	(260,171)
Net loss from discontinued operations	—	—	—	—	(311,549)
Capital expenditures	428	—	14,039	—	14,467
Total assets of continuing operations at December 31, 2015	1,078,778	261,942	200,348	961	1,542,029
Total assets of discontinued operations at December 31, 2015	—	—	—	—	128,006
December 31, 2014					
Revenues (including affiliates)	$266,085	$41,416	$42,031	$ —	$349,532
Gain on asset sales	1,366	—	20	—	1,386
Operating and maintenance expenses (including affiliates)	37,407	—	38,723	—	76,130

General and administrative (including affiliates)	—	—	—	10,545	10,545
Depreciation, depletion and amortization (including affiliates)	58,598	—	3,296	—	61,894
Asset impairment	26,209	—	—	—	26,209
Other expense, net	—	—	—	79,427	79,427
Net income (loss) from continuing operations	145,237	41,416	32	(89,972)	96,713
Net income from discontinued operations	—	—	—	—	12,117
Capital expenditures	5,351	—	171,116	—	176,467

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

5. Acquisitions and Divestitures

Acquisitions

On October 1, 2014, the Partnership completed its acquisition of VantaCore for total consideration of $200.6 million in cash and common units. The Partnership funded this acquisition through the borrowing of $169.0 million under its Opco's revolving credit facility and the issuance of 0.2 million common units to certain of the sellers. Revenue and operating income from VanataCore included in the Consolidated Statements of Comprehensive Income were $42.1 million and $0.1 million, respectively, for the year ended December 31, 2014.

On November 12, 2014, the Partnership completed its acquisition of non-operated oil and gas working interests in the Sanish Field of the Williston Basin from an affiliate of Kaiser-Francis Oil Company for $339.1 million. These non-operated working interest assets were sold during 2016 as discussed in Note 3. Discontinued Operations. The Partnership funded this acquisition using the net proceeds from the issuance of additional $125 million principal amount of its 9.125% Senior Notes due 2018, borrowing $117.0 million under an NRP Oil and Gas revolving credit facility and proceeds of $100.4 million from a public common unit offering. Revenue and operating income from these acquired oil and gas assets included in the Consolidated Statements of Comprehensive Income were $12.8 million and $3.7 million, respectively, for the year ended December 31, 2014.

These acquisitions were accounted for under the acquisition method of accounting for businesses. Accordingly, the Partnership conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the acquisition dates, while transaction and integration costs associated with the acquisitions were expensed as incurred. The results of operations of all acquisitions have been included in the consolidated financial statements since the acquisition dates. The following unaudited pro forma financial information (in thousands) presents a summary of the Partnership's consolidated revenues, net income and net income per common unit for the twelve months ended December 31, 2014 assuming the VantaCore and Sanish Field acquisitions had been completed as of January 1, 2014, including adjustments to reflect the values assigned to the net assets acquired:

	For the Year ended December 31, 2014
Total revenues and other income	$ 533,517
Net income	$ 122,319
Basic and diluted net income per common unit	$ 9.90

Divestitures

As discussed in Note 2. Summary of Significant Accounting Policies, the Partnership has been and is currently pursuing or considering a number of actions, including dispositions of assets, in order to mitigate the effects of adverse market developments which could otherwise cause the Partnership to breach financial covenants under its debt agreements, and mitigate the effects of scheduled debt principal payments that will strain the Partnership's liquidity. As part of this plan, the Partnership completed the sale of the following assets during the year ended December 31, 2016:

1)Oil and gas working interest in the Williston Basin for $116.1 million gross sales proceeds, as discussed in Note 3. Discontinued Operations.
2)Oil and gas royalty and overriding royalty interests in the Coal Royalty and Other segment in several producing properties located in the Appalachian Basin for $36.4 million gross sales proceeds. The effective date of the sale was January 1, 2016, and the Partnership recorded an $18.6 million gain from this sale included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income.
3)Aggregate reserves and related royalty rights in the Coal Royalty and Other segment at three aggregates operations located in Texas, Georgia and Tennessee for $10.0 million gross sales proceeds. The effective date of the sale was February 1, 2016, and the Partnership recorded a $1.5 million gain from this sale included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income.
4)In addition to the asset sales described above, during the year ended December 31, 2016, the Partnership sold mineral reserves within its Coal Royalty and Other segment in multiple sale transactions for cumulative $17.3 million of gross sales proceeds and recorded $8.6 million of cumulative gain from these sale transactions that are included in Gain on asset sales, net

on its Consolidated Statement of Comprehensive Income. These amounts primarily relate to eminent domain transactions with governmental agencies and the sale of additional oil and gas royalty interests.

Additional asset sales during the year included sales of land and plant and equipment within the Coal Royalty and Other segment for $1.2 million of gross proceeds and a $0.3 million of cumulative gain from these transactions that are included in Gain on asset sales, net on the Consolidated Statement of Comprehensive Income.

During the year ended December 31, 2015, the Partnership sold mineral reserves in multiple transactions for cumulative $3.5 million of gross sales proceeds and recorded a $3.3 million gain on asset sales included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income. The Partnership sold intangible assets for $4.4 million in gross proceeds and recorded a gain of $3.1 million included in Gain on asset sales, net in the Consolidated Statement of Comprehensive Income. The Partnership also sold plant and equipment $6.7 million of gross proceeds and recorded a gain of $0.6 million included in Gain on asset sales, net on the Consolidated Statement of Comprehensive Income.

During the year ended December 31, 2014, the Partnership sold land and mineral reserves for $1.4 million in gross sales proceeds and recorded a cumulative gain of $1.4 million on these asset sales included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income.

6. Equity Investment

The Partnership accounts for its 49% investment in Ciner Wyoming using the equity method of accounting. Ciner Wyoming distributed $46.6 million, $46.8 million and $46.6 million to the Partnership in the year ended December 31, 2016, 2015 and 2014, respectively.

The difference between the amount at which the investment in Ciner Wyoming is carried and the amount of underlying equity in Ciner Wyoming's net assets was $150.0 million and $154.8 million as of December 31, 2016 and 2015, respectively. This excess basis relates to plant, property and equipment and right to mine assets. The excess basis difference that relates to property, plant and equipment is being amortized into income using the straight-line method over a weighted average of 28 years. The excess basis difference that relates to right to mine assets is being amortized into income using the units of production method.

The Partnership's equity in the earnings of Ciner Wyoming is summarized as follows (in thousands):

	For the Year Ended December 31,		
	2016	2015	2014
Income allocation to NRP’s equity interests[1]	$44,882	$54,709	$47,354
Amortization of basis difference	(4,821)	(4,791)	(5,938)
Equity in earnings of unconsolidated investment	$40,061	$49,918	$41,416

(1) Includes reclassifications of accumulated other comprehensive loss to income allocation to NRP equity interest of $0.9 million, $0.7 million and $0.5 million for the year ended December 31, 2016, 2015 and 2014, respectively.

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

	For the Year Ended December 31,		
	2016	2015	2014
Sales	$475,187	$486,393	$465,032
Gross profit	114,232	131,493	118,439
Net Income	91,596	111,650	96,640

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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

	December 31,	
	2016	2015
Current assets	$134,616	$144,695
Noncurrent assets	235,427	233,845
Current liabilities	55,396	43,018
Noncurrent liabilities	98,425	116,808

The purchase agreement for the acquisition of the Partnership’s interest in Ciner Wyoming required the Partnership to pay additional contingent consideration to Anadarko to the extent certain performance criteria described in the purchase agreement were met by Ciner Wyoming in any of the years 2013, 2014 or 2015. During the first quarters of 2014, 2015 and 2016, the Partnership paid contingent consideration of $0.5 million, $3.8 million and $7.2 million, respectively, in contingent consideration to Anadarko for performance criteria met by Ciner Wyoming in 2013, 2014 and 2015, respectively. The Partnership has no further contingent consideration payments due to Anadarko under the purchase agreement.

7. Inventory

The components of inventories at December 31, 2016 and 2015 are as follows (in thousands):

	December 31,	
	2016	2015
Aggregates	$6,037	$7,056
Supplies and parts	856	779
Total inventory	$6,893	$7,835

8. Plant and Equipment

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

	December 31,	
	2016	2015
Plant and equipment at cost	$79,171	$92,049
Construction in process	557	646
Less accumulated depreciation	(30,285)	(32,020)
Total plant and equipment, net	$49,443	$60,675

Depreciation expense related to the Partnership's plant and equipment totaled $12.4 million, $15.9 million and $7.6 million for the year ended December 31, 2016, 2015 and 2014, respectively.

Impairment expense related to the Partnership's plant and equipment totaled $3.1 million, $7.7 million, and $0.8 million and are included in Asset impairments in the Consolidated Statements of Comprehensive Income for the year ending December 31, 2016, 2015 and December 31, 2014, respectively. During 2016, the Partnership recorded a $2.0 million impairment expense in its Coal Royalty and Other segment primarily related to a coal preparation plant and a $1.1 million impairment expense in its VantaCore segment primarily related to equipment write-downs. During the second quarter of 2015 the Partnership recorded a $2.3 million impairment expense related to a coal preparation plant and during the fourth quarter of 2015 the Partnership recorded a $4.7 million impairment expense related to coal processing and transportation assets and obsolete equipment. During 2015, the Partnership also recorded a $0.7 million impairment expense related to obsolete plant and equipment at VantaCore.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

9. Mineral Rights

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

	For the Year Ended December 31, 2016		
	Carrying Value	Accumulated Depletion	Net Book Value
Coal properties	$1,170,904	$(420,032)	$750,872
Aggregates properties	176,774	(39,056)	137,718
Oil and gas royalty properties	12,395	(6,289)	6,106
Other	14,946	(1,450)	13,496
Total	$1,375,019	$(466,827)	$908,192
	For the Year Ended December 31, 2015		
	Carrying Value	Accumulated Depletion	Net Book Value
Coal properties	$1,169,718	$(398,235)	$771,483
Aggregates properties	206,309	(35,752)	170,557
Oil and gas royalty properties	38,885	(9,994)	28,891
Other	14,947	(1,356)	13,591
Total	$1,429,859	$(445,337)	$984,522

Depletion expense related to the Partnership's mineral rights totaled $29.8 million, $40.4 million and $50.6 million for the year ended December 31, 2016, 2015 and 2014, respectively.

Impairment of Mineral Rights

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

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

During the years ended December 31, 2016, 2015 and 2014, the Partnership identified facts and circumstances that indicated that the carrying value of certain of its mineral rights exceed future cash flows from those assets and recorded non-cash impairment expense as follows (in thousands):

	For the years ended December 31,		
Impaired Asset Description	2016	2015	2014
Coal properties (1)	$12,088	$257,468	$16,793
Oil and gas properties (2)	36	70,527	—
Aggregates royalty properties (3)	1,677	43,402	3,013
Total	$13,801	$371,397	$19,806

(1) The Partnership recorded $12.1 million of coal property impairments during the year ended December 31, 2016, primarily as a result of lease surrender and termination. The Partnership recorded $3.8 million of coal property impairment during the three months ended September 30, 2016 and the fair value of the impaired asset recorded at fair value was $4.0 million at September 30, 2016. The Partnership recorded $8.2 million of coal property impairment during the three months ended December 31, 2016 and the fair value of the impaired asset recorded at fair value was $0.0 million at December 31, 2016.

Total coal property impairment expense for the year ended December 31, 2015 was $257.5 million. The Partnership recorded $1.5 million of coal property impairment during the three months ended June 30, 2015 and the fair value measurement of these impaired assets recorded at fair value was $0.0 million at June 30, 2015. The Partnership recorded $247.8 million of coal property impairment during the three months ended September 30, 2015 and the fair value of these impaired assets recorded at fair value was $28.4 million at September 30, 2015. The Partnership recorded the remaining $8.2 million of coal property impairment during the three months ended December 31, 2015 and the fair value of these impaired assets recorded at fair value was $0.4 million at December 31, 2015. These impairments primarily resulted from the continued deterioration and expectations of further reductions in global and domestic coal demand due to reduced global steel demand, sustained low natural gas prices, and continued regulatory pressure on the electric power generation industry. NRP compared net capitalized costs of its coal properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted future cash flows, the Partnership recorded an impairment for the excess of net capitalized cost over fair value. Significant inputs used to determine fair value include estimates of future cash flow, discount rate and useful economic life. Estimated cash flows are the product of a process that began with current realized pricing as of the measurement date and included an adjustment for risk related to the future realization of cash flows.

Total coal property impairment expense for the year ended December 31, 2014 was $16.8 million. This expense was recorded during the fourth quarter of 2014 when management 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. 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.

(2) The Partnership recorded $36 thousand of oil and gas royalty asset impairment during the year ended December 31, 2016. Total oil and gas royalty asset impairment expense for the year ended December 31, 2015 was $70.5 million. The Partnership recorded this impairment during the three months ended September 30, 2015. The fair value measurement of these impaired assets recorded at fair value were $13.0 million at September 30, 2015. This impairment primarily resulted from declines in future expected realized commodity prices and reduced expected drilling activity on its acreage. NRP compared net capitalized costs of its oil and gas royalty properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted future net cash flows, the Partnership recorded an impairment for the excess of net capitalized cost over fair value. A discounted

cash flow method was used to estimate fair value. Significant inputs used to determine the fair value include estimates of: (i) oil and gas reserves and risk-adjusted probable and possible reserves; (ii) future commodity prices; (iii) production costs, (iv) capital expenditures, (v) production and (vi) discount rates. The underlying commodity prices embedded in the Partnership's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing as of the measurement date, adjusted for estimated location and quality differentials.

(3) The Partnership recorded $1.7 million of aggregates royalty property impairments during the year ended December 31, 2016. Total aggregates property impairment expense for the year ended December 31, 2015 was $43.4 million.This impairment was recorded during the three months ended September 30, 2015. The fair value measurement of these impaired assets recorded at fair value was $13.1 million at September 30, 2015. This impairment primarily resulted from greenfield development projects that have not performed as projected, leading to recent lease concessions on minimums and royalties

combined with the continued regional market decline for certain properties. NRP compared net capitalized costs of its aggregates properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted cash flows, the Partnership recorded an impairment for the excess of net capitalized cost over fair value. A discounted cash flow model was used to estimate fair value. Significant inputs used to determine fair value include estimates of future cash flow, discount rate and useful economic life. Estimated cash flows are the product of a process that began with current realized pricing as of the measurement date and included an adjustment for risk related to the future realization of cash flows. Total aggregates property impairment expense for the year ended December 31, 2014 was $3.0 million.

10. Goodwill and Intangible Assets (Including Affiliate)

The Partnership's intangible assets—affiliate relate to above market coal transportation contracts with subsidiaries of Foresight Energy LP ("Foresight Energy") in which the Partnership receives throughput fees for the handling and transportation of coal as follows (in thousands):

	December 31,	
	2016	2015
Intangible assets—affiliate	$81,109	$81,109
Less accumulated amortization—affiliate	(31,298)	(28,112)
Total intangible assets, net—affiliate	$49,811	$52,997

Amortization expense related to the Partnership's intangible assets—affiliate totaled $3.2 million, $3.6 million and $3.3 million for the years ended December 31, 2016, 2015 and 2014, respectively.

The Partnership's intangible assets consist of permits, aggregate-related trade names and other agreements as follows (in thousands):

	December 31,	
	2016	2015
Intangible assets	$5,227	$5,076
Less accumulated amortization	(1,991)	(1,146)
Total intangible assets, net	$3,236	$3,930

Amortization expense related to the Partnership's intangible assets totaled $0.8 million, $1.0 million and $0.3 million for the years ended December 31, 2016, 2015 and 2014, respectively.

During the second quarter of 2014, the Partnership and a lessee amended an aggregates lease in its Coal Royalty and Other segment, 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.

For the Year Ended December 31,	Estimated Amortization Expense

	(in thousands)
2017	$ 3,559
2018	3,289
2019	3,275
2020	3,280
2021	3,280

The weighted average remaining amortization period for contract intangibles and other intangibles was 28 years and 16 years, respectively.

During the fourth quarter of 2014, $52.0 million of goodwill was added relating to the VantaCore acquisition. This amount represented the preliminary residual value. During 2015, the purchase price allocation was adjusted as more detailed analysis was completed and additional information was obtained about the facts and circumstances for VantaCore’s property, plant and equipment, right to mine assets and asset retirement obligations that existed as of the acquisition date. These adjustments decreased goodwill by $46.5 million and resulted in an acquisition date goodwill of $5.5 million.

During the fourth quarter of 2015, the Partnership evaluated goodwill for impairment and compared the estimated fair value of the VantaCore reporting unit to its carrying amount. The carrying amount exceeded fair value and the Partnership recorded a $5.5 million goodwill impairment expense include in Asset impairments on the Partnership's Consolidated Statements of Comprehensive Income. The lower fair value was primarily a result of the deterioration in certain regional markets in which VantaCore operates causing a decline in future performance levels compared to levels estimated during the purchase price allocation process. A discounted cash flow model was used to estimate fair value. Significant inputs used to determine fair value include estimates of future cash flow, discount rate and useful economic life. These estimates were based on current conditions and historical experience applied to develop projections of future operating performance.

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11. Debt and Debt—Affiliate

As of December 31, 2016 and 2015, Debt and debt—affiliate consisted of the following (in thousands):

	December 31, 2016	December 31, 2015
NRP LP debt [1]:		
9.125% senior notes, with semi-annual interest payments in April and October, due October 2018, $300 million issued at 99.007% and $125 million issued at 99.5% [2]	$425,000	$425,000
Opco debt [1]:		
Revolving credit facility, due June 2018 [2]	210,000	290,000
Senior notes		
4.91% with semi-annual interest payments in June and December, with annual principal payments in June, due June 2018	9,187	13,850
8.38% with semi-annual interest payments in March and September, with annual principal payments in March, due March 2019	64,029	85,714
5.05% with semi-annual interest payments in January and July, with annual principal payments in July, due July 2020	30,633	38,462
5.55% with semi-annual interest payments in June and December, with annual principal payments in June, due June 2023	18,825	21,600
4.73% with semi-annual interest payments in June and December, with annual principal payments in December, due December 2023	52,204	60,000
5.82% with semi-annual interest payments in March and September, with annual principal payments in March, due March 2024	119,524	135,000
8.92% with semi-annual interest payments in March and September, with annual principal payments in March, due March 2024	36,272	40,909
5.03% with semi-annual interest payments in June and December, with annual principal payments in December, due December 2026	134,035	148,077
5.18% with semi-annual interest payments in June and December, with annual principal payments in December, due December 2026	38,262	42,308
5.31% utility local improvement obligation, with annual principal and interest payments in February, due March 2021	961	1,153
NRP Oil and Gas debt:		
Revolving credit facility	—	85,000
Total debt at face value	$1,138,932	$1,387,073
Net unamortized debt discount	(1,322)	(2,077)
Net unamortized debt issuance costs [1]	(11,307)	(14,040)
Total debt, net	$1,126,303	$1,370,956
Less: current portion of long-term debt	138,903	80,745
Less: debt classified as non-current liabilities of discontinued operations	—	83,600
Total long-term debt	$987,400	$1,206,611

(1) See Note 2. Summary of Significant Accounting Policies for discussion of debt issuance costs reclassification upon adoption of new accounting standard on January 1, 2016.
(2) See Note 19. Subsequent Events for discussion of the March 2017 recapitalization transactions.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NRP LP Debt

NRP 2018 Senior Notes

In September 2013, the Partnership, together with NRP Finance Corporation ("NRP Finance"), a wholly owned subsidiary of the Partnership, as co-issuer, issued $300.0 million of 9.125% Senior Notes at an offering price of 99.007% of par (the "NRP 2018 Senior Notes"). Net proceeds after expenses from the issuance of NRP 2018 Senior Notes were approximately $289.0 million. The NRP 2018 Senior Notes call for semi-annual interest payments on April 1 and October 1 of each year, and will mature on October 1, 2018. None of the Partnership's subsidiaries guarantee the NRP 2018 Senior Notes.

In October 2014, the Partnership, together with NRP Finance as co-issuer, issued an additional $125.0 million of the NRP 2018 Senior Notes at an offering price of 99.5% of par. The additional issuance constituted the same series of securities as the existing NRP 2018 Senior Notes. Net proceeds of $122.6 million from the additional issuance of the NRP 2018 Senior Notes were used to fund a portion of the purchase price of NRP’s acquisition of non-operated working interests in oil and gas assets located in the Williston Basin in North Dakota.

The Partnership and NRP Finance have the option to redeem the NRP 2018 Senior Notes, in whole or in part, at any time on or after April 1, 2016, at fixed redemption prices specified in the indenture governing the NRP 2018 Senior Notes (the "2018 Indenture"). The 2018 Indenture contains covenants that, among other things, limit the ability of the Partnership and certain of its subsidiaries to incur or guarantee additional indebtedness. Under the 2018 Indenture, the Partnership 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 the Partnership and certain of its subsidiaries to incur additional indebtedness is further limited in the event the amount of indebtedness of the Partnership and certain of its subsidiaries that is senior to the Partnership's unsecured indebtedness exceeds certain thresholds.

Opco Debt

All of Opco’s debt is guaranteed by its wholly owned subsidiaries and is secured by certain of the assets of Opco and its wholly owned subsidiaries other than NRP Trona LLC, as further described below. As of December 31, 2016 and 2015, Opco was in compliance with the terms of the financial covenants contained in its debt agreements.

Opco Credit Facility

In June 2016, Opco entered into the first amendment (the "First Amendment") to its Amended and Restated Credit Agreement (the "Opco Credit Facility") that is guaranteed by all of Opco’s wholly owned subsidiaries, and is secured by liens on certain of the assets of Opco and its subsidiaries, as further described below. Under the First Amendment:

- The maturity date of the Opco Credit Facility was extended from October 1, 2017 to June 30, 2018;
- The maximum leverage ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the Opco Credit Facility) has been amended to remain at 4.0x for the remaining term of the Opco Credit Facility;
- The asset sale covenant was amended to allow asset sales of up to $300.0 million from and after the effective date of the First Amendment; provided, however, that 75% of the net cash proceeds of any such asset sales must be used to repay the Opco Credit Facility (without any corresponding commitment reduction) and/or NRP Opco’s Senior Notes described below.

On the effective date of the First Amendment, the total commitment under the Opco Credit Facility was reduced from $300.0 million to $260.0 million. In addition, Opco and the lenders agreed to further reduce commitments under the Opco Credit Facility to (a) $210.0 million on December 31, 2016, (b) $180.0 million on June 30, 2017 and (c) $150.0 million on December 31, 2017. Opco will have the right to delay any of these commitment reductions by up to 90 days each upon the agreement of the lenders holding 66.7% of the then-existing commitments. To the extent any such commitment reduction is extended under the terms of the A&R Revolving Credit Facility, Opco's ability to make distributions to the Partnership will be limited to amounts necessary for the Partnership to pay taxes and other general partnership expenses and make interest payments on its 9.125% Senior Notes due 2018.

In addition to the 4.0x leverage ratio described above, the Opco Credit Facility requires Opco to maintain a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease expense) of not less than 3.5 to 1.0. As of December 31, 2016, Opco's leverage ratio was 2.80x, and fixed charge coverage ratio was 4.99x.

Effective on the date of the First Amendment, indebtedness under the Opco Credit Facility bears interest, at Opco's option, at:

- 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 2.50% to 3.50%; or
- a rate equal to LIBOR plus an applicable margin ranging from 3.50% to 4.50%.

The weighted average interest rates for the borrowings outstanding under the Opco Credit Facility for the years ended December 31, 2016 and 2015 were 4.46% and 2.91%, respectively.

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

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

The Opco Credit Facility is collateralized and secured by liens on certain of Opco’s assets with carrying values of $673.0 million and $709.9 million classified as Land, Plant and equipment and Mineral rights on the Partnership’s Consolidated Balance Sheet as of December 31, 2016 and 2015, respectively. The collateral includes (1) the equity interests in all of Opco’s wholly owned subsidiaries, other than NRP Trona LLC (which owns a 49% non-controlling equity interest in Ciner Wyoming), (2) the personal property and fixtures owned by Opco’s wholly owned subsidiaries, other than NRP Trona LLC, (3) Opco’s material coal royalty revenue producing properties, (4) real property associated with certain of VantaCore’s construction aggregates mining operations, and (5) certain of Opco’s coal-related infrastructure assets.

Opco Senior Notes

Opco has issued several series of private placement senior notes (the "Opco Senior Notes") with various interest rates and principal due dates. As of December 31, 2016 and 2015, the Opco Senior Notes had cumulative principal balances of $503.0 million and $585.9 million, respectively. Opco made principal payments of $82.9 million on the Opco Senior Notes during the year ended December 31, 2016 and $80.8 million for the years ended December 31, 2015 and 2014.

The Note Purchase Agreements relating to the Opco Senior Notes contain covenants requiring Opco to:

- maintain a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the note purchase agreement) of no more than 4.0 to 1.0 for the four most recent quarters;
- not permit debt secured by certain liens and debt of subsidiaries to exceed 10% of consolidated net tangible assets (as defined in the note purchase agreement); and

- maintain the ratio of consolidated EBITDDA (as defined in the note purchase agreement) to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.0.

The 8.38% and 8.92% Opco Senior Notes also provide that in the event that Opco’s leverage ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the Note Purchase Agreements) 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. Opco has not exceeded the 3.75 to 1.00 ratio at the end of any fiscal quarter through December 31, 2016. As of December 31, 2016, Opco's leverage ratio was 2.80x, and fixed charge coverage ratio was 4.99x.

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In September 2016, Opco amended the Opco Senior Notes. Under this amendment, Opco agreed to use certain asset sale proceeds to make mandatory prepayment offers on the Opco Senior Notes as follows:

- Until the earlier of the time that (1) Opco has sold $300 million of assets and (2) June 30, 2020, Opco will be required to make prepayment offers to the holders of the Opco Senior Notes using 25% of the net cash proceeds from certain asset sales; and
- After the earlier to occur of the dates above, Opco will be required to make prepayment offers to the holders of the Opco Senior Notes using an amount of net cash proceeds from certain asset sales that will be calculated pro-rata based on the amount of Opco Senior Notes then outstanding compared to the other total Opco senior debt outstanding that is being prepaid.

The mandatory prepayment offers described above will be made pro-rata across each series of outstanding Opco Senior Notes and will not require any make-whole payment by Opco. In addition, the remaining principal and interest payments on the Opco Senior Notes will be adjusted accordingly based on the amount of Opco Senior Notes actually prepaid. The prepayments do not affect the maturity dates of any series of the Opco Senior Notes.

NRP Oil and Gas Debt Classified as Liabilities of Discontinued Operations

RBL Facility

In August 2013, NRP Oil and Gas entered into the RBL Facility, 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 owned non-operated working interests. The RBL Facility was secured by a first priority lien and security interest in substantially all of the assets of NRP Oil and Gas. NRP Oil and Gas was the sole obligor under the RBL Facility, and neither the Partnership nor any of its other subsidiaries was a guarantor of the RBL Facility.

At December 31, 2015, there was $85.0 million respectively, outstanding under the RBL Facility. As described in Note 3. Discontinued Operations, the Partnership included this debt and its related interest expense in discontinued operations. In July 2016, NRP Oil and Gas LLC closed the sale of its non-operated oil and gas working interest assets and used a portion of the proceeds to repay the RBL Facility in full.

Consolidated Principal Payments

The consolidated principal payments due are set forth below (in thousands):

	NRP LP Senior Notes		Opco Senior Notes (2)	Credit Facility	Total
2017	$ —		$80,638	$ 60,000	$140,638
2018	425,000	(1)	80,638	150,000	655,638
2019	—		76,045	—	76,045
2020	—		54,704	—	54,704
2021	—		47,043	—	47,043
Thereafter	—		164,864	—	164,864
	$ 425,000		$503,932	$ 210,000	$1,138,932

(1)

The 9.125% senior notes due 2018 were issued at a discount and were carried at $423.7 million as of December 31, 2016.

(2) Incudes $1.0 million utility local improvement obligation.

NATURAL RESOURCE PARTNERS L.P.
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12. Fair Value Measurements

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

	December 31, 2016		December 31, 2015	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Debt and debt—affiliate:				
NRP 2018 Senior Notes (1)	$420,097	$412,250	$417,296	$277,313
Opco Senior Notes and utility local improvement obligation (2)	500,174	488,814	584,890	383,065
Opco Revolving Credit Facility (3)	$206,032	$210,000	$285,170	$290,000
NRP Oil and Gas RBL Facility (3)	$—	$—	$83,600	$85,000
Assets:				
Contracts receivable—affiliate, current and long-term(2)	46,742	32,554	50,366	34,498

(1) The Level 1 fair value is based upon quotations obtained for identical instruments on the closing trading prices near period end.
(2) The Level 3 fair value is estimated by management using quotations obtained for comparable instruments on the closing trading prices near period end.
(3) The Level 3 fair value approximates the outstanding borrowing amount because the interest rates are variable and reflective of market rates and the terms of the credit facility allow the Partnership to repay this debt at any time without penalty.

13. Related Party Transactions

Reimbursements to Affiliates of our General Partner

The Partnership’s general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with the partnership agreement, the general partner and its affiliates are reimbursed for services provided to the Partnership and for expenses incurred on the Partnership’s behalf. Employees of Quintana Minerals Corporation ("QMC") and Western Pocahontas Properties Limited Partnership ("WPPLP"), affiliates of the Partnership, provide their services to manage the Partnership's business. QMC and WPPLP charge the Partnership the portion of their employee salary and benefits costs related to their employee services provided to NRP. In addition, the Partnership receives non-cash equity contributions from its general partner related to compensation paid directly by the general partner and not reimbursed by the Partnership. These amounts are presented as non-cash equity contributions on the Partnership's Consolidated Statements of Partners' Capital and were $0.3 million and $0.8 million during the years ended December 31, 2016 and 2015, respectively. These QMC and WPPLP employee management service costs and non-cash equity compensation expenses are presented as Operating and maintenance expenses—affiliates, net and General and administrative—affiliates on the Consolidated Statements of Comprehensive Income. NRP also reimburses overhead costs incurred by its affiliates to manage the Partnership's business. These overhead costs include certain rent, legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by or on behalf of the Partnership's general partner and its affiliates and are presented as Operating and maintenance expenses—affiliates, net and General and administrative—affiliates on the Consolidated Statements of Comprehensive Income.

The Partnership had Accounts payable—affiliates to QMC of $0.4 million and $1.1 million, including less than $0.1 million and $0.6 million related to discontinued operations at December 31, 2016 and 2015, respectively, for services provided by QMC to the Partnership. The Partnership had Accounts payable—affiliates to WPPLP of $0.6 million and $0.3 million at December 31, 2016 and 2015, respectively.

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Direct general and administrative expenses charged to the Partnership by WPPLP and QMC are as follows (in thousands):

	For the Year Ended December 31,		
	2016	2015	2014
Operating and maintenance expenses—affiliates, net	9,891	10,063	9,166
General and administrative—affiliates	3,591	5,312	3,258

Included in income (loss) from discontinued operations are $1.3 million, $0.7 million and $0.6 million of operating and maintenance expenses charged by QMC for the year ended December 30, 2016, 2015 and 2014, respectively.

Cline Affiliates

Various companies affiliated with Chris Cline, including Foresight Energy LP, lease coal reserves from the Partnership, and the Partnership also leases coal transportation assets to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest (unaudited) in the NRP's general partner, as well as approximately 0.5 million of NRP's common units (unaudited) at December 31, 2016.

Coal related revenues from Foresight Energy totaled $63.4 million, $86.6 million and $81.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. As of December 31, 2016 and 2015, the Partnership had Accounts receivable—affiliates from Foresight Energy of $6.5 million and $6.4 million, respectively. As of December 31, 2016 and 2015, the Partnership had received $71.6 million and $82.6 million, respectively in minimum royalty payments to date that have been recorded as Deferred revenue—affiliates since they have not been recouped by Foresight Energy.

NRP owns and leases rail load out and associated facilities to Foresight Energy at Foresight Energy's Sugar Camp mine. The lease agreement is accounted for as a direct financing lease. Total projected remaining payments under the lease at December 31, 2016 were $76.4 million with unearned income of $31.8 million, and the net amount receivable was $44.6 million, of which $2.2 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliate on the accompanying Consolidated Balance Sheets. Minimum lease payments are $5.0 million per year for the next five years and represent a $1.25 million per quarter in deficiency payment. Total projected remaining payments under the lease at December 31, 2015 were $81.2 million with unearned income of $35.4 million and the net amount receivable was $45.9 million, of which $2.0 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliates on the accompanying Consolidated Balance Sheets.

NRP holds a contractual overriding royalty interest from a subsidiary of Foresight Energy that provides for payments based upon production from specific tons at Foresight Energy's Sugar Camp operations. This overriding royalty was accounted for as a financing arrangement and is reflected as an affiliate receivable. The net amount receivable under the agreement as of December 31, 2016 was $2.7 million, of which $1.4 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliate. The net amount receivable under the agreement as of December 31, 2015 was $4.9 million, of which $1.5 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliate on the accompanying Consolidated Balance Sheets.

NRP owns rail load out transportation assets and subcontracts out the operating responsibilities to an affiliate of Foresight Energy at Foresight's Williamson mine. During the years ended December 31, 2016, 2015 and 2014, the Partnership recorded operating and maintenance expenses—affiliates of $1.3 million, $1.4 million and $1.6 million, respectively, to operate these assets.

During the years ended December 31, 2016, 2015 and 2014, the Partnership recognized a gain of $0.0 million, $9.3 million and $5.7 million, respectively on a reserve swap at Foresight Energy's Williamson mine. The gain is included in Coal royalty and other—affiliates revenues on the Consolidated Statements of Comprehensive Income. The Level 3 fair value of the reserves was estimated using a discounted cash flow model. The expected cash flows were developed using estimated annual sales tons, forecasted sales prices and anticipated market royalty rates.

Long-Term Debt—Affiliate

Donald R. Holcomb, one of the Partnership’s former directors, was a manager of Cline Trust Company, LLC (the "Cline Trust Company"). As of December 31, 2015, Cline Trust Company owned approximately 0.5 million of the Partnership’s common units and $20.0 million in principal amount of the Partnership’s 9.125% Senior Notes due 2018. As of December 31, 2015, the members of the Cline Trust Company were four trusts for the benefit of the children of Chris Cline, each of which owns an approximately equal membership interest in the Cline Trust Company. As of December 31, 2015, Mr. Holcomb also served as trustee of each of the four trusts. The balance on this portion of the Partnership’s 9.125% Senior Notes due 2018 was $19.9 million as of December 31, 2015 and was included in Long-term debt, net—affiliate on the accompanying Consolidated Balance Sheet. In April 2016, Mr. Holcomb resigned from the Partnership's board of directors and as a result the $19.9 million debt balance held by Cline Trust Company was subsequently reclassified as Long-term debt, net on the Partnership's accompanying Consolidated Balance Sheet.

Quintana Capital Group GP, Ltd.

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

At December 31, 2016, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp ("Corsa")., a coal mining company traded on the TSX Venture Exchange that is one of the Partnership’s lessees in Tennessee. Corbin J. Robertson III, one of the Partnership’s directors, is Chairman of the Board of Corsa. Coal related revenues from Corsa totaled $2.2 million, $3.1 million and $3.0 million for the years ended December 31, 2016, 2015 and 2014, respectively.

As of December 31, 2016 and 2015 the Partnership had recorded $0.0 million and $0.3 million, respectively in minimum royalty payments to date as Deferred revenue—affiliates since they have not been recouped by Corsa. The Partnership also had Accounts receivable—affiliates totaling $0.2 million and $0.2 million from Corsa at December 31, 2016 and 2015, respectively.

WPPLP Production Royalty and Overriding Royalty

For the year ended December 31, 2016, the Partnership recorded $0.7 million in operating and maintenance expenses—affiliates related to a non-participating production royalty payable to WPPLP pursuant to a conveyance agreement entered into in 2007. These charges were $0.4 million and zero for the years ended December 31, 2015 and 2014, respectively. The Partnership had Other assets—affiliate from WPPLP of $1.0 million and $1.1 million at December 31, 2016 and December 31, 2015, respectively related to a non-production royalty receivable from WPPLP for overriding royalty interest on a mine.

14. Commitments and Contingencies

Legal

NRP 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.

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

Foresight Energy Disputes

In November 2015, we filed a lawsuit against Foresight Energy’s subsidiary, Hillsboro Energy LLC ("Hillsboro"), in the Circuit Court of the Fourth Judicial Circuit in Montgomery County, Illinois. The lawsuit alleges, among other items, breach of contract by Hillsboro resulting from a wrongful declaration of force majeure at Hillsboro’s Deer Run mine in July 2015. In late March 2015, elevated carbon monoxide readings were detected at the Deer Run mine, and coal production at the mine was idled. In July 2015, we received the notice declaring a force majeure event at the mine as a result of the elevated carbon monoxide levels. We believe the force majeure claim by Hillsboro has no merit and we are vigorously pursuing recovery against them. However, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us minimum deficiency payments of $7.5 million per quarter, or $30.0 million per year. Foresight Energy's failure to make the deficiency payment with respect to 2015 and 2016 resulted in a cumulative $46.0 million negative cash impact to us. Such amount will increase for each quarter during which mining operations continue to be idled. We do not currently have an estimate as to when the mine will resume coal production. If the mine remains idled for an extended period or if the mine is permanently closed, our financial condition could be adversely affected.

In April 2016, we filed a lawsuit against Macoupin Energy, LLC ("Macoupin"), a subsidiary of Foresight Energy, in Macoupin County, Illinois. The lawsuit alleges that Macoupin has failed to comply with the terms of its coal mining, rail loadout and rail loop leases by incorrectly recouping previously paid minimum royalties. Foresight Energy’s failure to properly calculate its recoupable balance and failure to make payments in accordance with these lease agreements has resulted in a cumulative $6.2 million negative cash impact to us. While the Partnership plans to pursue its claim, a valuation allowance for the receivable amount has been recorded.

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, 2016. The Partnership is not associated with any material 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. As a former 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 during the period it was an owner. The Partnership is also responsible for losses and liabilities, including environmental liabilities that may arise from uninsured and underinsured events at its VantaCore operations.

15. Major Customers

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

	For the Years Ended December 31,					
	2016		2015		2014	
	Revenues	Percent	Revenues	Percent	Revenues	Percent
Foresight Energy	$63,355	15.8 %	$86,614	19.7 %	$81,546	23.2 %
Alpha Natural Resources	$18,184	4.5 %	$34,364	7.8 %	$48,783	13.9 %

All of the revenue related to the customers above is included in revenues of the Coal Royalty and Other segment.

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The Partnership had a significant concentration of revenues with Foresight Energy and Alpha Natural Resources. The exposure is currently spread out over a number of different mining operations and leases. During the year ended December 31, 2015, total revenues and other income from Alpha Natural Resources included a $6.0 million non-recurring lease assignment fee.

16. Unit-Based Compensation

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.

Phantom units are incentive based equity awards issued to employees over a vesting period that entitle the grantee to receive the cash equivalent to the value of a unit of the Parent common units upon each vesting. The Partnership records compensation cost equal to the fair value of the award at the measurement date, which is determined to be the earlier of the performance commitment date or the service completion date. In addition, compensation cost for unvested phantom unit awards is adjusted quarterly for any changes in the Partnership's unit price. 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.

In connection with the phantom unit awards, the Compensation, Nominating and Governance Committee also granted tandem Distribution Equivalent Rights ("DERs"), which entitle the holders to receive distributions equal to the distributions paid on the Partnership's common units between the date the units are granted and the vesting date. The DERs are payable in cash upon vesting but may be subject to forfeiture if the grantee ceases employment prior to vesting.

A summary of activity in the outstanding grants during 2016 is as follows (in thousands):

	Phantom Units
Outstanding grants at January 1, 2016	126
Grants during the period	—
Grants vested and paid during the period	(28)
Forfeitures during the period	(12)
Outstanding grants at December 31, 2016	86

Grants typically vest at the end of a four-year period and are paid in cash upon vesting. The Partnership recorded a credit to general and administrative expenses related to its Long-Term Incentive Plan of $3.4 million for the year ended December 31, 2015, due to the decline in the market price of the Partnership's common units during 2015. For the years ended December 31, 2016 and 2014 the Partnership recorded G&A expenses of $1.4 million and $1.0 million, respectively.

In connection with the Long-Term Incentive Plans, payments are typically made during the first quarter of the year. Payments of $1.5 million, $4.4 million and $6.5 million were made during the years ended December 31, 2016, 2015, and 2014, respectively. The grant date fair value was $0.0 million, $4.2 million and $6.6 million for awards in 2016, 2015 and 2014, respectively. The unaccrued cost associated with unvested outstanding grants and related DERs at December 31, 2016 and December 31, 2015, was $0.8 million and $0.7 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

17. Cash Distributions

The following table shows the distributions paid by the Partnership during the year ended December 31, 2016, 2015 and 2014:

			Total Distributions (In thousands)		
Date Paid	Period Covered by Distribution	Distribution per Common Unit	Common Units	GP Interest	Total
2016					
February 12, 2016	October 1 - December 31, 2015	$ 0.45	$5,503	$ 113	$5,616
May 13, 2016	January 1 - March 31, 2016	0.45	5,503	113	5,616
August 12, 2016	April 1 - June 30, 2016	0.45	5,505	112	5,617
November 14, 2016	July 1 - September 30, 2016	0.45	5,503	113	5,616
2015					
February 13, 2015	October 1 - December 31, 2014	$ 3.50	$42,804	$ 874	$43,678
May 14, 2015	January 1 - March 31, 2015	0.90	11,007	225	11,232
August 14, 2015	April 1 - June 30, 2015	0.90	11,009	223	11,232
November 13, 2015	July 1 - September 30, 2015	0.45	5,504	112	5,616
2014					
January 31, 2014	October 1 - December 31, 2013	$ 3.50	$38,433	$ 785	$39,218
May 14, 2014	January 1 - March 31, 2014	3.50	38,634	787	39,421
August 14, 2014	April 1 - June 30, 2014	3.50	38,938	795	39,733
November 14, 2014	July 1 - September 30, 2014	3.50	42,796	874	43,670

18. Deferred Revenue and Deferred Revenue—Affiliate

Most of the Partnership’s coal and aggregates lessees must pay the Partnership minimum annual or quarterly amounts which are generally recoupable out of actual production over certain time periods. These minimum payments are recorded as a deferred revenue liability 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. The Partnership’s deferred revenue (including affiliate) consist of the following (in thousands):

	December 31, 2016	December 31, 2015
Deferred revenue	$44,931	$80,812
Deferred revenue—affiliate	71,632	82,853
Total deferred revenue (including affiliate)	$116,563	$163,665

The Partnership recognized the following amounts of deferred revenue (including affiliate) attributable to previously paid minimums as Coal royalty and other revenue (in thousands):

	For the Year Ended December 31,		
	2016	2015	2014
Coal royalty and other	$49,284	$3,451	$6,659
Coal royalty and other—affiliates	15,307	12,038	—
Total coal royalty and other (including affiliates)	$64,591	$15,489	$6,659

NATURAL RESOURCE PARTNERS L.P.
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Lease Modifications, Termination and Forfeitures of Minimum Royalty Balances

During the year ended December 31, 2016, the Partnership entered into agreements with certain lessees to either modify or terminate existing coal related leases that resulted in the Partnership recognizing $40.5 million of deferred revenue as follows:

- An agreement that terminated a central Appalachia coal royalty lease and resulted in the lessee forfeiting the right to recoup $26.2 million of minimum royalties previously paid to the Partnership. The Partnership agreed to transfer its coal mineral rights that were subject to this former lease to the lessee. This terminated lease had no current or planned production and the mineral rights transferred had zero net book value on the Partnership's consolidated Balance Sheets as of March 31, 2016. As a result of this transaction, in April 2016 the Partnership recognized $26.2 million of revenue.
- Lease modifications, terminations and forfeitures of existing coal royalty and other leases resulted in lessee forfeiture of rights to recoup previously paid minimum royalties and the reduction in lessee recoupment time. As a result of these modifications, in the first and second quarters of 2016 the Partnership recognized $10.7 million of revenue.
- The Partnership recognized $3.6 million of revenue from various other coal and aggregates lease modifications, terminations and forfeitures during the year ended December 31, 2016.

During the years ended December 31, 2015 and 2014, there was less than $0.1 million and $1.4 million of revenue recognized from coal and aggregate lease modifications, terminations or forfeitures, respectively.

19. Subsequent Events

The following represents material events that have occurred subsequent to December 31, 2016 through the time of the Partnership’s filing of its Annual Report on Form 10-K with the SEC:

Distribution Declared

On February 14, 2017, the Partnership paid a distribution of $0.45 per unit to unitholders of record on February 7, 2017.

Recapitalization Transactions

On March 2, 2017, the Partnership completed the following recapitalization transactions:

Issuance of Preferred Units and Warrants

NRP issued $250 million of Class A Convertible Preferred Units representing limited partner interests in NRP (the "Preferred Units") to Blackstone and GoldenTree (together the "Preferred Purchasers") pursuant to a Preferred Unit and Warrant Purchase Agreement. NRP issued 250,000 Preferred Units to the Preferred Purchasers at a price of $1,000 per Preferred Unit (the "Per Unit Purchase Price"), less a 2.5% structuring and origination fee. The Preferred Units entitle the Preferred Purchasers to receive cumulative dividends at a rate of 12% per year, up to one half of which NRP may pay in additional Preferred Units (such additional Preferred Units, the "PIK Units"). NRP also issued two tranches of warrants (the "Warrants") to purchase common units to the Preferred Purchasers (Warrants to purchase 1.75 million common units with a strike price of $22.81 and Warrants to purchase 2.25 million common units with a strike price of $34.00). The Warrants may be exercised by the holders thereof at any time before the eighth anniversary of the closing date. Upon exercise of the Warrants, NRP may, at its option, elect to settle the Warrants in common units or cash, each on a net basis.

The Preferred Units have a perpetual term, unless converted or redeemed as described below. The Preferred Units (including any PIK Units) are convertible into common units at the election of the holders (1) after the fifth anniversary and prior to the eighth anniversary of the issue date at a 7.5% discount to the volume weighted average trading price of our common units (the "VWAP") for the 30 trading days immediately prior to the notice of conversion if the 30-day VWAP immediately prior to such notice is greater than $51.00 (subject to a maximum of 33% of the Preferred Units per year) and (2) after the eighth anniversary of the issue date at a 10% discount to the VWAP for the 30 trading days immediately prior to the notice of conversion. Instead of issuing common units pursuant to clause (1) of the preceding sentence, NRP has the option to redeem the Preferred Units proposed to be converted for cash at a price equal to the Per Unit Purchase Price, plus the value of any accrued and unpaid distributions. To the extent the holders of the Preferred Units have not elected to convert their Preferred Units by the twelfth anniversary of the issue date, NRP has the right to force conversion of the Preferred Units into common units at a 10% discount to the VWAP for the 30 trading days immediately prior to the notice of conversion. In addition, NRP has the ability to redeem at any time (subject to compliance with our debt agreements) all or any portion of the Preferred Units (including PIK Units) for cash at the agreed upon per unit amount, which is calculated as the Per Unit Purchase Price multiplied by (i) prior to the third anniversary of the closing date, 1.50, (ii) on or after the third anniversary of the closing date and prior to the fourth anniversary of the closing date, 1.70 and (iii) on or after the fourth anniversary of the closing date, 1.85.

The terms of the Preferred Units contain certain restrictions on our ability to pay distributions on our common units. To the extent that either (i) our consolidated Leverage Ratio (as defined in the Restated Partnership Agreement) is greater than 3.25x, or (ii) the ratio of our Distributable Cash Flow to cash distributions made or proposed to be made is less than 1.2x (in each case, with respect to the most recently completed four-quarter period), NRP may not increase the quarterly distribution above $0.45 per quarter without the approval of the holders of a majority of the outstanding Preferred Units. In addition, if at any time after January 1, 2022, any PIK Units are outstanding, NRP may not make distributions on its common units until it has redeemed all PIK Units for cash.

The holders of the Preferred Units have the right to vote with holders of NRP’s common units on an as-converted basis and have other customary approval rights with respect to changes of the terms of the Preferred Units. In addition, Blackstone has certain approval rights over certain matters, including:

- the incurrence of new indebtedness, subject to certain exceptions;
- material changes to NRP’s business;
- acquisitions and divestitures in excess of certain dollar thresholds;
- amendments to material contracts resulting in a cash impact to NRP in excess of certain dollar thresholds;
- settlement of any litigation or regulatory matter resulting in cash payments by NRP in excess of certain thresholds; and
- amendments to related party contracts outside of the ordinary course of business.

GoldenTree also has more limited approval rights that will expand once Blackstone's ownership goes below the Minimum Preferred Unit Threshold (as defined below). The Preferred Purchaser Approval Rights are not transferrable without NRP's consent. In addition, the Preferred Purchaser Approval Rights held by Blackstone and GoldenTree will terminate at such time that Blackstone (together with their affiliates) or GoldenTree (together with their affiliates), as applicable, no longer own at least 20% of the total number of Preferred Units issued on the closing date, together with all PIK Units that have been issued but not redeemed (the "Minimum Preferred Unit Threshold"). To the extent any Preferred Units that have converted into common units are still held by the applicable Preferred Purchaser (or its affiliates), such common units will be deemed to represent a number of Preferred Units based on the weighted average number of common units issued in each conversion and will count towards the Minimum Preferred Unit Threshold.

The foregoing terms of the Preferred Units are reflected in our Fifth Amended and Restated Agreement of Limited Partnership, dated as of March 2, 2017, which is filed as Exhibit 3.2 to this Annual Report on Form 10-K and incorporated herein by reference. The terms of the Warrants are reflected in the Form of Warrant to Purchase Common Units filed as Exhibit 4.28 to this Annual Report on Form 10-K, which is incorporated herein by reference.

At the closing, pursuant to a Board Representation and Observation Rights Agreement, the Preferred Purchasers received certain board appointment and observation rights and appointed one director and one observer to the Board of Directors of GP Natural Resource Partners LLC. For more information on these rights, see "Certain Relationships and Related Transactions, and Director Independence—Board Representation and Observation Rights Agreement."

NRP also entered into a registration rights agreement (the "Preferred Unit and Warrant Registration Rights Agreement") with the Preferred Purchasers, pursuant to which NRP is required to file (i) a shelf registration statement to register the common units issuable upon exercise of the Warrants and to cause such registration statement to become effective not later than 90 days following the closing date and (ii) a shelf registration statement to register the common units issuable upon conversion of the Preferred Units and to cause such registration statement to become effective not later than the earlier of the fifth anniversary of the closing date or 90 days following the first issuance of any common units upon conversion of Preferred Units (the "Registration Deadlines"). In addition, the Preferred Unit and Warrant Registration Rights Agreement gives the Preferred Purchasers piggyback registration and demand underwritten offering rights under certain circumstances. If the shelf registration statements are not effective by the applicable Registration Deadline, NRP will be required to pay the Preferred Purchasers liquidated damages in the amounts and upon the term set forth in the Preferred Unit and Warrant Registration Rights Agreement.

Opco Credit Facility Amendment

NRP entered into the Second Amendment to Opco's Third Amended and Restated Credit Agreement to extend the term thereof until April 2020, and reduced the commitments of the lenders to $180 million (from $210 million) effective at the closing of the recapitalization transactions. Pursuant the Second Amendment, commitments under the Opco Credit Facility will be reduced to $150 million at December 31, 2017 and further reduced to $100 million at December 31, 2018 through maturity in April 2020. The amendment does not change the pricing grid or financial covenants under the Opco Credit Facility; provided, however, that if NRP increases its quarterly distribution to its common unitholders above $0.45 per common unit, the maximum leverage ratio under the Opco Credit Facility will permanently decrease from 4.0x to 3.0x. Other terms of the Second Amendment include revisions to the mandatory prepayment provisions with respect to net cash proceeds received from certain asset sales and additional limitations on the ability of Opco and its subsidiaries to make certain investments. The Second Amendment is filed as Exhibit 10.14 to this Annual Report on Form 10-K and is incorporated herein by reference.

Issuance of 2022 Notes; Exchange and Redemption of 2018 Notes

NRP and NRP Finance issued $346 million aggregate principal amount of 10.500% Senior Notes due 2022 to several holders of its 2018 Notes. Of the $346 million of 2022 Notes issued, $241 million in aggregate principal amount were issued in exchange for $241 million in aggregate principal amount of 2018 Notes, and $105 million of the 2022 Notes were issued to the holders in exchange for cash. The 2022 Notes are issued under an Indenture dated as of March 2, 2017 (the "2022 Indenture"), bear interest at 10.500% per year, are payable semi-annually on March 15 and September 15, beginning September 15, 2017, and mature on March 15, 2022.

NRP and NRP Finance have the option to redeem the 2022 Notes, in whole or in part, at any time on or after March 15, 2019, at the redemption prices (expressed as percentages of principal amount) of 105.25% for the 12-month period beginning March 15, 2019, 102.625% for the 12-month period beginning March 15, 2020, and thereafter at 100.000%, together, in each case, with any accrued and unpaid interest to the date of redemption. Furthermore, before March 15, 2019, NRP may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net proceeds of certain public or private equity offerings at a redemption price of 110.500% of the principal amount of 2022 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 2022 Notes issued under the 2022 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 2022 Indenture, the holders of the 2022 Notes may require us to purchase their 2022 Notes at a purchase price equal to 101% of the principal amount of the 2022 Notes, plus accrued and unpaid interest, if any. The 2022 Notes purchased for cash were issued at a price of 98.75% (original issue discount of 1.25%), and each holder exchanging 2018 Notes received a fee of 5.813% of the aggregate principal amount of all 2018 Notes tendered for exchange by such holder, as well as all accrued and unpaid interest thereon.

The 2022 Indenture contains restrictive covenants that are substantially similar to those contained in the Indenture governing the 2018 Notes, except that the debt incurrence and restricted payments covenants contain additional restrictions. Under the debt incurrence covenant, NRP's non-guarantor restricted subsidiaries will not be permitted to incur additional indebtedness unless their consolidated leverage ratio is less than 3.00x (measured on a pro forma basis and assuming that the greater of (i) $150.0 million of debt (or, if less, at NRP's election, the amount of total lending commitments under any revolving credit facility) and (ii) the actual amount of debt outstanding is outstanding under any revolving credit facility); provided, however, that such non-guarantor restricted subsidiaries will be permitted to make up to $150 million in borrowings under a revolving credit facility (which amount will be reduced on a dollar-for-dollar basis to the extent we have made the election described in clause (i) above). Under the restricted payments covenant, NRP will not be able to increase the quarterly distribution on its common units or elect to pay more than 50% of the distributions required to be made on the Preferred Units in the form of cash, unless, in each case, our consolidated leverage ratio is less than 4.00x. The 2022 Indenture also contains restrictions on NRP's ability to redeem the Preferred Units.

The 2022 Notes are the senior unsecured obligations of NRP and NRP Finance. The 2022 Notes rank equal in right of payment to all existing and future senior unsecured debt of NRP and NRP Finance, including the remaining outstanding 2018 Notes, and senior in right of payment to any of NRP's subordinated debt. The 2022 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 are structurally subordinated in right of payment to all existing and future debt and other liabilities of our subsidiaries, including the Opco Credit Facility and each series of Opco’s existing senior notes. None of NRP's subsidiaries guarantee the 2022 Notes.

The terms of the 2022 Notes are more fully described in the 2022 Indenture, which is filed as Exhibit 4.24 to this Annual Report on Form 10-K and incorporated herein by reference.

NRP entered into a registration rights agreement (the "Notes Registration Rights Agreement") with the holders of the 2022 Notes, pursuant to which we and NRP Finance agreed to file a registration statement with the Securities and Exchange Commission for the benefit of the holders of the 2022 Notes so that such holders can exchange the 2022 Notes for exchange securities that have substantially identical terms as the 2022 Notes. NRP and NRP Finance agreed to use commercially reasonable efforts to cause the exchange to be completed within 180 days after the closing and will be required to pay additional interest, as specified in the Notes Registration Rights Agreement, if NRP fails to comply with its obligations to register the 2022 Notes within the specified time periods.

NRP expects to redeem $90 million in aggregate principal amount of the 2018 Notes at a redemption price of 104.563%, and pay all accrued and unpaid interest thereon, in April 2017. In addition, NRP is required to redeem any and all remaining outstanding 2018 Notes (and pay accrued and unpaid interest thereon) within 60 days after October 1, 2017.

NATURAL RESOURCE PARTNERS L.P.
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

As discussed in Note 3. Discontinued Operations, the Partnership sold its non-operated oil and gas working interest assets in July 2016 and exited this business. The Partnership prepared the following oil and gas information in accordance with the authoritative guidance for oil and gas extractive activities for the years ended December 31, 2015 and 2014.

Capitalized Costs for the year ended December 31, 2015 (in thousands):

Proven properties	$199,404
Unproven properties	—
Total property, plant, and equipment	199,404
Accumulated depreciation, depletion, and amortization	(60,542)
Net capitalized costs	$138,862

Costs incurred for property acquisitions, exploration, and development (in thousands):

	For the Years Ended December 31,	
	2015	2014
Property acquisitions		
Proven properties	$—	$298,627
Unproven properties	—	40,800
Development	29,080	5,340
Total	$29,080	$344,767

Results of Operations for Producing Activities (in thousands):

	For the Years Ended December 31,	
	2015	2014
Production revenue	$49,201	$48,834
Royalty and overriding royalty revenue (1)	4,364	10,732
Total oil and gas related revenue	53,565	59,566
Operating costs and expense:		
Depreciation, depletion and amortization	40,772	23,936
Property, franchise and other taxes	5,210	5,529
Production costs	12,871	12,544
Impairment of oil and gas properties	367,576	—
Total operating costs and expense	426,429	42,009
Total income from operations	$(372,864)	$17,557

(1) Includes $0.4 million and $1.9 million for the years ended December 31, 2015 and 2014, respectively of nonproduction revenues including lease bonus payments

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. The Partnership estimated proved reserves as of December 31, 2015 and 2014 were prepared by a third party independent reserve engineer. To achieve reasonable certainty, the third party engineer employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data

NATURAL RESOURCE PARTNERS L.P.
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

used in the estimation of the Partnership's 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 third party engineer prepared its report covering properties representing 100% of the Partnership's estimated proved reserves as of December 31 2015 and 2014. Prices were calculated using the unweighted average of the first-day-of-the-month pricing for the twelve months ended December 31, 2015 and 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.

The following table shows our estimated domestic proved reserves and reserve additions and revisions:

	Crude Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)(2)	Total Proved Reserves (MBoe)(3)
December 31, 2014	9,983	1,229	14,370	13,607
Revisions of previous estimates	(1,451)	89	701	(1,244)
Extensions, discoveries and other additions	776	60	541	926
Sales of properties	(98)	—	(62)	(108)
Production	(1,136)	(156)	(2,226)	(1,663)
December 31, 2015 (1)	8,074	1,222	13,324	11,518
Proved developed reserves as of December 31, 2015	7,862	1,196	13,157	11,251
Proved undeveloped reserves as of December 31, 2015	212	26	167	267

(1) Includes reserves attributable to the Partnership's 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) Includes 10,063MBoe of estimated proved reserves attributable to the Partnership's non-operated working interests in oil and natural gas properties in the Williston Basin, approximately 3% of which were proved undeveloped reserves.

The standardized measure of discounted future net cash flows from our estimated proved oil and gas reserves is as follows for the year ended December 31, 2015 (in thousands):

Future cash inflows	$364,352
Less related future:	
Production costs	(164,649)
Development and abandonment costs	(7,826)
Future net cash flows before 10% discount	191,877
Discount to present value at a 10% annual rate	(75,524)
Total standardized measure of discounted net cash flows	$116,353

NATURAL RESOURCE PARTNERS L.P.
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

The table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves during the year ended December 31, 2015 (in thousands):

Beginning of the period	$305,197
Revisions to previous estimates:	
Changes in prices and costs	(188,946)
Changes in quantities	(11,750)
Changes in future development costs	(12,202)
Previously estimated development costs incurred during the period	29,080
Additions to proved reserves from extensions, discoveries and improved recovery, less related costs	11,928
Purchases and sales of reserves in place, net	(3,851)
Accretion of discount	31,795
Sales of oil and gas, net of production costs	(35,112)
Production timing and other	(9,786)
Net increase (decrease)	(188,844)
End of period	$116,353

NATURAL RESOURCE PARTNERS L.P.
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following table summarizes quarterly financial data for 2016 and 2015 (in thousands, except per unit data):

	First Quarter (1)	Second Quarter	Third Quarter	Fourth Quarter	Total 2016
2016					
Revenues (including affiliates)	$73,902	$119,317	$91,448	$86,311	$370,978
Gains on asset sales (2)	21,925	(1,071)	6,426	1,801	29,081
Depreciation, depletion and amortization (including affiliates)	10,502	11,176	12,831	11,763	46,272
Asset impairment	1,893	91	5,697	9,245	16,926
Income from operations	48,991	70,741	38,907	27,106	185,745
Net income from continuing operations	26,351	48,633	16,419	3,811	95,214
Net income (loss) from discontinued operations	(2,924)	(2,187)	7,112	(323)	1,678
Net income from continuing operations per limited partner unit	$2.11	$3.90	$1.32	$0.31	$7.65
Net income (loss) from discontinued operations per limited partner unit	$(0.23)	$(0.18)	$0.57	$(0.03)	$0.13
Weighted average number of common units outstanding	12,232	12,232	12,232	12,232	12,232

	First Quarter (1)	Second Quarter	Third Quarter	Fourth Quarter (3)	Total 2015
2015					
Revenues (including affiliates)	$94,447	$120,228	$112,199	$105,874	$432,748
Gains on asset sales	1,615	3,455	1,833	(3)	6,900
Depreciation, depletion and amortization (including affiliates)	11,514	19,077	16,437	13,888	60,916
Asset impairment (4)	—	3,803	361,703	19,039	384,545
Income (loss) from operations	46,499	58,324	(307,831)	32,581	(170,427)
Net income (loss) from continuing operations	24,379	36,389	(330,736)	9,797	(260,171)
Net income (loss) from discontinued operations	(6,890)	(3,811)	(269,265)	(31,583)	(311,549)
Net income (loss) from continuing operations per limited partner unit	$1.95	$2.82	$(26.34)	$0.78	$(20.78)
Net income (loss) from discontinued operations per limited partner unit	$(0.55)	$(0.31)	$(21.57)	$(2.53)	$(24.97)
Weighted average number of common units outstanding	12,232	12,232	12,232	12,232	12,232

(1) As a result of the sale of its non-operated oil and gas working interest business effective April 1, 2016, the Partnership classified the operating results and cash flows of its non-operated oil and gas working interest assets as discontinued operations in its consolidated statements of comprehensive income subsequent to the filing of the First Quarter 2016 Form 10-Q. See below for a reconciliation to the amounts reported in the First Quarter 2016 Form 10-Q.

(2) During the first quarter of 2016 the Partnership sold oil and gas royalty and aggregates royalty assets for a cumulative gain of $21.9 million. During the third quarter of 2016 the Partnership sold assets in multiple sale transactions for a net gain of $6.4 million primarily related to eminent domain transactions with governmental agencies.

(3) As a result of the sale of its non-operated oil and gas working interest business effective April 1, 2016, the Partnership classified the operating results and cash flows of its non-operated oil and gas working interest assets as discontinued operations in its consolidated statements of comprehensive income subsequent to the filing of the 2015 Form 10-K where this quarter's results were previously reported. See below for a reconciliation to the amounts reported in the 2015 Form 10-K.

NATURAL RESOURCE PARTNERS L.P.
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

(4) See Note 9. Mineral Rights for asset impairment discussion.

The following table reconciles previously reported quarterly information to the quarterly financial data disclosed above (in thousands, except per unit data):

	As Previously Reported	Reclassified to Discontinued Operations	Revised
First Quarter 2016			
Revenues	$ 80,826	$ (6,924)	$73,902
Gains on asset sales	21,925	—	21,925
Depreciation, depletion and amortization	14,743	(4,241)	10,502
Asset impairment	2,030	(137)	1,893
Income from operations	47,156	1,835	48,991
Net income from continuing operations	23,427	2,924	26,351
Net income (loss) from discontinued operations	—	(2,924)	(2,924)
Net income from continuing operations per limited partner unit	$ 1.88	$ 0.23	$2.11
Net income (loss) from discontinued operations per limited partner unit	$ —	$ (0.23)	$(0.23)
Weighted average number of common units outstanding	12,232		12,232
First Quarter 2015			
Revenues	$ 107,611	$ (13,164)	$94,447
Gains on asset sales	2,066	(451)	1,615
Depreciation, depletion and amortization	25,392	(13,878)	11,514
Asset impairment	—	—	—
Income from operations	40,417	6,082	46,499
Net income from continuing operations	17,489	6,890	24,379
Net income (loss) from discontinued operations	—	(6,890)	(6,890)
Net income from continuing operations per limited partner unit	$ 1.40	$ 0.55	$1.95
Net income (loss) from discontinued operations per limited partner unit	$ —	$ (0.55)	$(0.55)
Weighted average number of common units outstanding	12,232		12,232

	As Reported	Presentation Reclassification	Reclassified to Discontinued Operations	As Revised
Fourth Quarter 2015				
Revenues	$116,063	$ 3	$ (10,192)	$105,874
Gains on asset sales	—	(3)	—	(3)
Depreciation, depletion and amortization	18,152	—	(4,264)	13,888
Asset impairment	50,953	—	(31,914)	19,039
Income from operations	2,042	—	30,539	32,581
Net income from continuing operations	(21,786)	—	31,583	9,797
Net income (loss) from discontinued operations	—	—	(31,583)	(31,583)
Net income from continuing operations per limited partner unit	$(1.75)	$ —	$ 2.53	$0.78
	$—	$ —	$ (2.53)	$(2.53)

Net income (loss) from discontinued operations per limited partner unit		
Weighted average number of common units outstanding	12,232	12,232

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2016. This evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures were effective as of December 31, 2016 at the reasonable assurance level in producing the timely recording, processing, summary and reporting of information and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosures.

Management’s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2016 based on the framework in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission "2013 Framework" (COSO). Based on that evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2016. No changes were made to our internal control over financial reporting during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

Report of Independent Registered Public Accounting Firm

The Partners of Natural Resource Partners L.P.

We have audited Natural Resource Partners L.P.’s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Natural Resource Partners L.P.’s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company’s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Natural Resource Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2016 and 2015, and the related consolidated statements of comprehensive income (loss), partners’ capital and cash flows for each of the three years in the period ended December 31, 2016 and our report dated March 6, 2017 expressed an unqualified opinion there thereon.
/s/ Ernst & Young LLP
Houston, Texas
March 6, 2017

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE MANAGING GENERAL PARTNER AND CORPORATE GOVERNANCE

As a master limited partnership we do not employ any of the people responsible for the management of our properties. Instead, we reimburse affiliates of our managing general partner, GP Natural Resource Partners LLC, for their services. The following table sets forth information concerning the directors and officers of GP Natural Resource Partners LLC as of the date of this Annual Report on Form 10-K. Each officer and director is elected for their respective office or directorship on an annual basis. Unless otherwise noted below, the individuals served as officers or directors of the partnership since the initial public offering. Subject to the Investor Rights Agreement with Adena Minerals, LLC, and the Board Representation and Observation Rights Agreement with Blackstone and GoldenTree. Mr. Robertson is entitled to nominate eleven 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, and the right to nominate one director to Blackstone.

Name	Age	Position with the General Partner
Corbin J. Robertson, Jr.	69	Chairman of the Board and Chief Executive Officer
Wyatt L. Hogan	45	President and Chief Operating Officer
Craig W. Nunez	55	Chief Financial Officer and Treasurer
Christopher J. Zolas	42	Chief Accounting Officer
Kevin J. Craig	48	Executive Vice President, Coal
Kathy H. Roberts	65	Vice President, Investor Relations
Kathryn S. Wilson	42	Vice President, General Counsel and Secretary
Gregory F. Wooten	61	Vice President, Chief Engineer
Robert T. Blakely	75	Director
Russell D. Gordy	66	Director
L. G. (Trey) Jackson III	41	Director
Robert B. Karn III	75	Director
Jasvinder S. Khaira	35	Director
S. Reed Morian	71	Director
Richard A. Navarre	56	Director
Corbin J. Robertson, III	46	Director
Stephen P. Smith	56	Director
Leo A. Vecellio, Jr.	70	Director

Corbin J. Robertson, Jr. has served as Chief Executive Officer and Chairman of the Board of Directors of GP Natural Resource Partners LLC since 2002. Mr. Robertson has vast business experience having founded and served as a director and as an officer of multiple companies, both private and public, and has served on the boards of numerous non-profit organizations. He has served as the Chief Executive Officer and Chairman of the Board of the general partner of Great Northern Properties Limited Partnership since 1992 and Quintana Minerals Corporation since 1978, as Chairman of the Board of Directors of New Gauley Coal Corporation since 1986, and the general partner of Western Pocahontas Properties Limited Partnership since 1986. In addition, Mr. Robertson served as Chief Executive Officer of the general partner of Western Pocahontas Properties Limited Partnership from 1986 until 2008 and currently serves on the Board of Managers of Premium Resources, LLC. He also serves as a Principal with Quintana

Capital Group, Chairman of the Board of the Cullen Trust for Higher Education and on the boards of the American Petroleum Institute, the National Petroleum Council, the Baylor College of Medicine and the Spirit Golf Association. In 2006, Mr. Robertson was inducted into the Texas Business Hall of Fame. Mr. Robertson is the father of Corbin J. Robertson, III.

Wyatt L. Hogan has served as President and Chief Operating Officer of GP Natural Resource Partners LLC since March 2015. From September 2014 through February 2015, Mr. Hogan served as President of GP Natural Resource Partners LLC. Mr. Hogan was Executive Vice President of GP Natural Resource Partners from December 2013 through August 2014 and Vice President, General Counsel and Secretary of GP Natural Resource Partners from May 2003 to December 2013. Mr. Hogan joined NRP in 2003 from Vinson & Elkins L.L.P., where he practiced corporate and securities law from August 2000 through April 2003. Mr. Hogan also serves as Executive Vice President of Quintana Minerals Corporation, New Gauley Coal Corporation, the general partner of Western Pocahontas Properties Limited Partnership and the general partner of Great Northern Properties Limited Partnership, and from 2003 to October 2013, Mr. Hogan served as General Counsel and Secretary of those entities. He is also a member of the Board of Directors of Quintana Minerals Corporation and represents NRP as one of its appointees to the Board of Managers of Ciner Wyoming LLC. Mr. Hogan also serves as a member of the Board of the National Mining Association and the American Coalition for Clean Coal Electricity. Mr. Hogan has been involved in numerous charitable organizations and currently serves on the Boards of Kids' Meals, Inc. and the Kinkaid Investment Foundation and serves as Chairman of the Board of the Kinkaid Alumni Association.

Craig W. Nunez has served as Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC since January 2015. Prior to joining NRP, Mr. Nunez was an owner and Chief Executive Officer of Bocage Group, a private investment company specializing in energy, natural resources and master limited partnerships since March 2012. In addition, until joining NRP, he was a FINRA-registered Investment Advisor Representative with Searle & Co since July 2012 and served as an Executive Advisor to Capital One Asset Management since January 2014. From September 2011 through March 2012, Mr. Nunez served as the Executive Vice President and Chief Financial Officer of Quicksilver Resources Canada, Inc. Mr. Nunez was Senior Vice President and Treasurer of Halliburton Company from January 2007 until September 2011, and Vice President and Treasurer of Halliburton Company from February 2006 to January 2007. Prior to that, he was Treasurer of Colonial Pipeline Company from November 1995 to February 2006. Mr. Nunez has been involved in numerous charitable organizations and currently serves on the boards of Goodwill Industries of Houston and Medical Bridges, Inc.

Christopher J. Zolas has served as Chief Accounting Officer of GP Natural Resource Partners since March 2015. Prior to joining NRP, Mr. Zolas served as Director of Financial Reporting at Cheniere Energy, Inc., a publicly traded energy company, where he performed financial statement preparation and analysis, technical accounting and SEC reporting for five separate SEC registrants, including a master limited partnership. Mr. Zolas joined Cheniere Energy, Inc. in 2007 as Manager of SEC Reporting and Technical Accounting and was promoted to Director in 2009. Prior to joining Cheniere Energy, Inc., Mr. Zolas worked in public accounting with KPMG LLP from 2002 to 2007.

Kevin J. Craig has served as Executive Vice President, Coal of GP Natural Resource Partners since September 2014. Mr. Craig was the Vice President of Business Development for GP Natural Resource Partners LLC since 2005. Mr. Craig also represents NRP as one of its appointees to the Board of Managers of Ciner Wyoming LLC. Mr. Craig joined NRP in 2005 from CSX Transportation, where he served as Terminal Manager for the West Virginia Coalfields. He has extensive marketing, finance and operations experience within the energy industry. Mr. Craig served as a member of the West Virginia House of Delegates having been elected in 2000 and re-elected in 2002, 2004, 2006, 2008, 2010 and 2012. In addition to other leadership positions, Delegate Craig served as Chairman of the Committee on Energy. Mr. Craig did not seek re-election in 2014 and his term ended January 2015. Prior to joining CSX, he served as a Captain in the United States Army. Mr. Craig has served as the Chairman of the Huntington Regional Chamber of Commerce Board of Directors and continues as a member of both the West Virginia Chamber of Commerce and the Huntington Regional Chamber of Commerce’s respective board of directors. He is involved in numerous state coal associations and serves as a member of the Board of Directors of BrickStreet Mutual Insurance Company.

Kathy H. Roberts is Vice President, Investor Relations of GP Natural Resource Partners LLC. Ms. Roberts joined NRP in July 2002. She was the Principal of IR Consulting Associates from 2001 to July 2002 and from 1980 through 2000 held various financial and investor relations positions with Santa Fe Energy Resources, most recently as Vice President-Public Affairs. She is a Certified Public Accountant. Ms. Roberts currently serves on the Board of Directors of the Master Limited Partnership Association and has served on the local board of directors of the National Investor

Relations Institute. She has also served on the Executive Committee and as a National Vice President of the Institute of Management Accountants.

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

Gregory F. Wooten has served as Vice President, Chief Engineer of GP Natural Resource Partners LLC since December 2013. Mr. Wooten joined NRP in 2007, serving as Regional Manager. Prior to joining NRP, Mr. Wooten served as Vice President, COO and Chief Engineer of Dingess Rum Properties, Inc., where he managed coal, oil, gas and timber properties from 1982 until 2007. Prior to 1982, Mr. Wooten worked as a planning and production engineer in the coal industry and is a member of the American Institute of Mining, Metallurgical, and Petroleum Engineers. Mr. Wooten has served as Chairman of the National Council of Coal Lessors since 2015.

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

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

L. G. (Trey) Jackson III joined the Board of Directors of GP Natural Resource Partners LLC in April 2016. Mr. Jackson brings financial and coal industry experience to the Board of Directors. Mr. Jackson is currently the Managing Director of the Cline Group, a group of companies affiliated with Christopher Cline, having served in that capacity since March 2011, where he has responsibility for mergers and acquisitions, deal structuring and certain other commercial activities. Also during this time, from June 2013 until August 2015, Mr. Jackson served as the President of Convent Marine Terminal. Prior to joining Mr. Cline’s management group, Mr. Jackson served in various capacities at two energy private equity firms and a boutique investment bank. Mr. Jackson also serves on the Board of Directors of Material Sciences Corp.

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

Jasvinder S. Khaira joined the Board of Directors of GP Natural Resource Partners LLC in March 2017. Mr. Khaira brings extensive financial and investing experience to the Board of Directors. Mr. Khaira currently is a Senior Managing Director in the Tactical Opportunities group at The Blackstone Group L.P. Mr. Khaira joined Blackstone as a member of its Private Equity Group in 2004. Mr. Khaira has been designated to serve as a director of GP Natural Resource Partners LLC by Blackstone Tactical Opportunities, pursuant to its right to designate a director to the Board of Directors of GP Natural Resource Partners LLC. Since joining Blackstone, Mr. Khaira has been involved in a variety of investments and strategic business initiatives at Blackstone.

S. Reed Morian joined the Board of Directors of GP Natural Resource Partners LLC in 2002. Mr. Morian has vast executive business experience having served as Chairman and Chief Executive Officer of several companies since the early 1980s and serving on the board of other companies. Mr. Morian has served as a member of the Board of Directors of the general partner of Western Pocahontas Properties Limited Partnership since 1986, New Gauley Coal Corporation since 1992 and the general partner of Great Northern Properties Limited Partnership since 1992. Mr. Morian also serves on the Board of Managers of Premium Resources, LLC since 2006. Mr. Morian worked for Dixie Chemical Company from 1971 to 2006 and served as its Chairman and Chief

Executive Officer from 1981 to 2006. He has also served as Chairman, Chief Executive Officer and President of DX Holding Company since 1989. He formerly served on the Board of Directors for the Federal Reserve Bank of Dallas-Houston Branch from April 2003 until December 2008 and as a Director of Prosperity Bancshares, Inc. from March 2005 until April 2009.

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

Corbin J. Robertson, III joined the Board of Directors of GP Natural Resource Partners LLC in May 2013. Mr. Robertson has experience with investments in a variety of energy businesses, having served both in management of private equity firms and having served on several boards of directors. Mr. Robertson has served as a Co-Managing Partner of LKCM Headwater Investments GP, LLC and LKCM Headwater Investments I, L.P., a private equity fund, since June 2011. He has served as the Chief Executive Officer of the general partner of Western Pocahontas Properties Limited Partnership since May 2008, and has served on the Board of Directors of Quintana Minerals Corporation since 2007 and Western Pocahontas since October 2012. Mr. Robertson also has served on the Board of Managers of Premium Resources, LLC since 2016. Mr. Robertson also co-founded Quintana Energy Partners, an energy-focused private equity firm in 2006, and served as a Managing Director thereof from 2006 until December 2010. Mr. Robertson has served on the Board of Directors for Quintana Minerals Corporation since October 2007, and previously served as Vice President-Acquisitions for GP Natural Resource Partners LLC from 2003 until 2005. Mr. Robertson also serves on the Board of Directors of the general partner of Genesis Energy L.P., a publicly traded master limited partnership, as well as Corsa Coal Corp, Buckhorn Energy Services and LL&B Minerals, each of which is in the energy business. Mr. Robertson is the son of Corbin J. Robertson, Jr.

Stephen P. Smith joined the Board of Directors of GP Natural Resource Partners LLC in 2004. Mr. Smith brings extensive public company financial experience in the power and energy industries to the Board of Directors. Mr. Smith formerly served as Chief Financial Officer and Chief Accounting Officer of the general partner of Columbia Pipeline Partners L.P. from December 2014 and as a Director from September 2014 until June 2016. Mr. Smith also formerly served as Executive Vice President and Chief Financial Officer of Columbia Pipeline Group. Mr. Smith served as Executive Vice President and Chief Financial Officer for NiSource, Inc. from June 2008 to June 2015. Prior to joining NiSource, he held several positions with American Electric Power Company, Inc, including Senior Vice President - Shared Services from January 2008 to June 2008, Senior Vice President and Treasurer from January 2004 to December 2007, and Senior Vice President - Finance from April 2003 to December 2003. From November 2000 to January 2003, Mr. Smith served as President and Chief Operating Officer - Corporate Services for NiSource Inc. Prior to joining NiSource, Mr. Smith served as Deputy Chief Financial Officer for Columbia Energy Group from November

1999 to November 2000 and Chief Financial Officer for Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company from 1996 to 1999.

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

Corporate Governance

Board Meetings and Executive Sessions

The Board met 16 times in 2016. During 2016, our non-management directors met in executive session several times. The presiding director was Mr. Blakely, the Chairman of our Compensation, Nominating and Governance Committee, or CNG Committee. In addition, our independent directors met one time in executive session in December 2016. Mr. Blakely was the presiding director at that meeting. Interested parties may communicate with our non-management directors by writing a letter to the Chairman of the CNG Committee, NRP Board of Directors, 1201 Louisiana Street, Suite 3400, Houston, Texas 77002.

In April 2016, Donald R. Holcomb resigned from the Board of Directors of GP Natural Resource Partners LLC, and L.G. (Trey) Jackson, III was appointed to the Board. In March 2017, Jasvinder Khaira was appointed to the Board by Blackstone.

Independence of Directors

The Board of Directors has affirmatively determined that Messrs. Blakely, Gordy, Karn, Navarre, Smith and Vecellio are independent based on all facts and circumstances considered by the Board, including the standards set forth in Section 303A.02(a) of the NYSE’s listing standards. Although we had a majority of independent directors in 2016, because we are a limited partnership as defined in Section 303A of the NYSE’s listing standards, we are not required to do so. The Board has an Audit Committee, a Compensation, Nominating and Governance Committee, and a Conflicts Committee, each of which is staffed solely by independent directors.

Audit Committee

Our Audit Committee is comprised of Robert B. Karn III, who serves as chairman, Robert T. Blakely, Richard A. Navarre and Stephen P. Smith. Mr. Karn, Mr. Blakely, Mr. Navarre and Mr. Smith are "Audit Committee Financial Experts" as determined pursuant to Item 407 of Regulation S-K. During 2016, the Audit Committee met seven times.

Report of the Audit Committee

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

During 2016, at each of its meetings, the Audit Committee met with the senior members of our financial management team, our general counsel and our independent auditors. The Audit Committee had private sessions at certain of its meetings with our independent auditors and the senior members of our financial management team and the general counsel at which candid discussions of financial management, accounting and internal control and legal issues took place.

The Audit Committee approved the engagement of Ernst & Young LLP as our independent auditors for the year ended December 31, 2016 and reviewed with our financial managers and the independent auditors overall audit scopes and plans, the results of internal and external audit examinations, evaluations by the auditors of our internal controls and the quality of our financial reporting.

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

The Committee also discussed with the independent auditors other matters required to be discussed by the auditors with the Committee by PCAOB Auditing Standard No. 16, Communications With Audit Committees. The Committee received and discussed with the auditors their annual written report on their independence from the partnership and its management, which is made under

Rule 3526, Communication With Audit Committees Concerning Independence, and considered with the auditors whether the provision of non-audit services provided by them to the partnership during 2016 was compatible with the auditors' independence.

In performing all of these functions, the Audit Committee acts only in an oversight capacity. The Audit Committee reviews our Quarterly Reports on Form 10-Q and Annual Reports on Form 10-K prior to filing with the Securities and Exchange Commission. In 2016, the Audit Committee also reviewed quarterly earnings announcements with management and representatives of the independent auditor in advance of their issuance. In its oversight role, the Audit Committee relies on the work and assurances of our management, which has the primary responsibility for financial statements and reports, and of the independent auditors, who, in their report, express an opinion on the conformity of our annual financial statements with U.S. generally accepted accounting principles.

In reliance on these reviews and discussions, and the report of the independent auditors, the Audit Committee has recommended to the Board of Directors, and the Board has approved, that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2016, for filing with the Securities and Exchange Commission.

Robert B. Karn III, Chairman
Robert T. Blakely
Richard A. Navarre
Stephen P. Smith

Compensation, Nominating and Governance Committee

Executive officer compensation is administered by the CNG Committee, which is comprised of four members. Mr. Blakely, the Chairman, has served on the CNG Committee since 2003. Mr. Karn has served on the CNG Committee since 2002. Mr. Vecellio joined the Committee in 2007, and Mr. Gordy joined the CNG Committee in 2013. The CNG Committee has reviewed and approved the compensation arrangements described in the Compensation Discussion and Analysis section of this Annual Report on Form 10-K. During 2016, the CNG Committee met four times. Our Board of Directors appoints the CNG Committee and delegates to the CNG Committee responsibility for:

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

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

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of their equity securities. These people are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required for transactions occurring in 2015, and we believe that our officers and directors and persons who beneficially own more than ten percent of a registered class of our equity securities complied with all filing requirements with respect to transactions in our equity securities during 2016.

Partnership Agreement

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

Corporate Governance Guidelines and Code of Business Conduct and Ethics

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

NYSE Certification

Pursuant to Section 303A of the NYSE Listed Company Manual, in 2016, Corbin J. Robertson, Jr. certified to the NYSE that he was not aware of any violation by the Partnership of NYSE corporate governance listing standards.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Overview

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

Executive Officer Compensation Strategy and Philosophy

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Historically, our primary business objective was to generate cash flows at levels that could sustain long-term quarterly cash distributions to our investors. However, given the difficult coal markets over the past few years, coupled with the limitations on our ability to access capital from additional sources, our current objective is to preserve long-term equity value for our unitholders by using our excess free cash flow to reduce our leverage. Our objective in determining the compensation of our executive officers is to retain qualified people to manage the business through a difficult market cycle. Although we historically have not tied our compensation to achievement of specific financial targets or fixed performance criteria, we have reevaluated that strategy in light of current market conditions. See "—Evaluation of 2016 Performance; Components of Compensation-Long-Term Incentive Compensation-2016 Cash Long-Term Incentive Plan" below.

The 2016 compensation for executive officers consisted of four primary components:

- base salaries;
- annual cash incentive awards, including cash payments made by our general partner based on the cash distributions it receives from the common units that it owns (which we refer to herein as "GP Bonus Awards");
- long-term equity and cash incentive compensation; and
- perquisites and other benefits.

In December 2015, our CNG Committee reviewed the performance of the executive officers and the amount of time expected to be spent by each NRP officer on NRP business, and determined the salaries for each officer for 2016. All of our named executive officers, other than Corbin J. Robertson, Jr., our Chairman and Chief Executive Officer and Kathryn S. Wilson, our Vice President, General Counsel and Secretary, spent 100% of their time on NRP matters during 2016, and NRP bears the cost of their time. Mr. Robertson has historically spent approximately 50% of his time on NRP matters. Mr. Robertson does not receive a salary or an annual bonus in his capacity as Chief Executive Officer. Rather, Mr. Robertson has historically been compensated exclusively through long-term incentive awards and through GP Bonus Awards. Mr. Robertson also directly or indirectly owns in excess of 20% of the outstanding common units of NRP, and thus his interests are directly aligned with our unitholders. In 2016, Ms. Wilson spent approximately 94% of her time on NRP matters and the rest of her time on private Robertson family owned company matters, and her time has been allocated to NRP accordingly.

Historically, in February of each year, the CNG Committee has approved the year-end bonuses for the year just ended and long-term incentive awards for the executive officers. The CNG Committee considers the performance of the partnership, the performance of the individuals and the outlook for the future in determining the amounts of the awards. Because we are a partnership, tax and accounting conventions make it more costly for us to issue additional common units or options as incentive compensation. Consequently, we have no outstanding options or restricted units and currently have no plans to issue options or restricted units in the future. Instead, prior to 2016, we issued phantom units, coupled with tandem distribution equivalent rights ("DERs"), to our executive officers that are paid in cash based on the average closing price of our common units for the 20-day trading period prior to vesting. The phantom units and DERs typically vest four years from the date of grant. In past years, these awards have served to align the executive officers' interests with those of our unitholders.

During 2015, given the sharp decline in NRP's unit price, the Board of Directors recognized that the value of the executive officers' phantom unit awards and the decreased GP Bonus Awards no longer provided long-term incentive or retention value to management. Accordingly, the Board authorized and directed the CNG Committee to begin a review of options for a new long-term incentive program for NRP management to be adopted in 2016. Upon the conclusion of this review, in February 2016, the CNG Committee elected not to award additional phantom units under the long-term incentive plan and instead adopted a new cash long-term incentive plan and recommended the new plan and forms of award agreements thereunder to the Board for approval. The Board approved the new plan and awards in February 2016 and approved awards to officers under the plan in March 2016. In March 2017, the Board determined that the conditions to the vesting of the performance awards had been met as a result of the completion of the 2017 recapitalization transactions described elsewhere in this Annual Report on Form 10-K. See "—Evaluation of 2016 Performance; Components of Compensation-Long-Term Incentive Compensation-2016 Cash Long-Term Incentive Plan" below.

In light of the recently completed recapitalization transactions, the CNG Committee is evaluating a new long-term incentive program that best reflects the current outlook for NRP. Accordingly, no long-term incentive awards have yet been made during 2017. The CNG Committee and the Board may determine to award additional cash incentive awards, phantom unit awards or other forms of long-term incentive compensation during 2017.

Role of Compensation Experts

Historically, the CNG Committee periodically has utilized consultants to get a basic sense of the market, but has considered the advice of the consultant as only one of many factors among the other items discussed in this compensation discussion and analysis. For a more detailed description of the CNG Committee and its responsibilities, see "Item 10. Directors and Executive Officers of the Managing General Partner and Corporate Governance" in this Annual Report on Form 10-K.

During 2015, at the direction of the Board, the CNG Committee retained Meridian Compensation Partners ("Meridian") to advise on a new long-term incentive strategy to be implemented in 2016 in order to incentivize and retain management in light of the significant decrease in phantom unit award value and GP Bonus Awards. See "—Evaluation of 2016 Performance; Components of Compensation-Long-Term Incentive Compensation-2016 Cash Long-Term Incentive Plan" below. In selecting Meridian as its compensation consultant, the CNG Committee assessed the independence of Meridian pursuant to SEC rules and considered, among other things, whether Meridian provides any other services to NRP, the policies of Meridian that are designed to prevent any conflict of interest between Meridian, the CNG Committee and NRP, any personal or business relationship between Meridian and a member of the CNG Committee or one of NRP's executive officers and whether Meridian owned any of NRP's common units. In addition to the foregoing, the CNG Committee received documentation from Meridian addressing the firm's independence. Meridian was engaged directly by the CNG Committee, reported exclusively to the CNG Committee and does not provide any additional services to NRP. The CNG Committee concluded that Meridian is independent and did not have any conflicts of interest. While management did cooperate with Meridian in collecting data with respect to NRP's compensation programs, the CNG Committee determined that management had not attempted to influence Meridian's review or recommendations.

Role of Our Executive Officers in the Compensation Process

Mr. Hogan, our President and Chief Operating Officer, provided Mr. Robertson with recommendations relating to the executive officers other than himself in connection with the evaluation of the 2016 compensation programs.
Mr. Robertson considered those recommendations and provided the CNG Committee with recommendations for all of the executive officers other than himself. Mr. Robertson relied on his personal experience in setting compensation over a number of years in determining the appropriate amounts for each employee, and considered each of the factors described elsewhere in this compensation discussion and analysis. Mr. Robertson and Mr. Hogan attended the CNG Committee meetings at which the Committee deliberated and approved the compensation, but were excused from the meetings when the CNG Committee discussed their compensation. Mr. Nunez and Ms. Wilson also participated in the meetings with Meridian and the CNG Committee with respect to the design and implementation of the 2016 Cash Long-Term Incentive Plan.

Evaluation of 2016 Performance; Components of Compensation

2016 Performance

Our Board of Directors considers Adjusted EBITDA, distributable cash flow and overall leverage to be the critical measures in evaluating NRP's performance. Despite the continued depressed coal and oil and gas markets in 2016, we recorded Adjusted EBITDA in 2016 of $255.5 million, which was essentially flat compared to our Adjusted EBITDA in 2015, and distributable cash flow of $271.4 million, which increased from $176.6 million in 2015 primarily as a result of cash proceeds from asset sales in 2016.

Other factors considered by the CNG Committee in determining total management compensation for 2016 included:

- the sale of approximately $181 million of assets during 2016, including $116.1 million of oil and gas working interests and royalty interests that marked NRP's strategic exit from the non-operated oil and gas working interest business;
- the permanent reduction in NRP's debt of approximately $248 million during 2016;
- the extension in 2016 of the maturity date under Opco's revolving credit facility to June 2018;
- the increase in the trading price of NRP's common units of over 300% during 2016;
- overall cost reductions; and
- additional revenue of $40 million recognized in connection with lease amendments in the coal segment.

Base Salaries

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

In determining salaries for NRP's executive officers for 2016, at the December 2015 meeting, the CNG Committee considered the financial performance of NRP for the nine months ended September 30, 2015 as well as the projected financial performance of NRP for the fourth quarter of 2015 and for the year ending December 31, 2016. The CNG Committee also considered the individual performance of each member of the executive management team during 2015 and the changes to the management team that became effective during the year. Based on its review, the CNG Committee approved the salaries disclosed in the Summary Compensation Table below.

Annual Cash Incentive Awards

Each named executive officer participated in two cash incentive programs in 2016, with the exception of Mr. Robertson who did not participate in the cash bonus program. The first program is a discretionary cash bonus award approved in February 2017 by the CNG Committee based on similar criteria used to evaluate the annual base salaries. The bonuses awarded with respect to 2016 under this program are disclosed in the Summary Compensation

Table under the Bonus column. As with the base salaries, there are no formulas or specific performance targets related to these awards. The bonuses for Mr. Hogan, Mr. Nunez, Ms. Wilson and Mr. Zolas were increased over the prior year in part to offset the declines in other components of their compensation and in recognition of their contributions to NRP.

Under the second cash incentive program (the GP Bonus Award program), our general partner has set aside the cash distributions it receives on an annual basis with respect to distributions on NRP's common units held by our general partner for awards to our executive officers, including Mr. Robertson. Although Mr. Robertson has the sole discretion to determine the GP Bonus Awards allocated to each executive officer, including himself, the cash awards that our officers receive under this plan are reviewed by the CNG Committee and taken into account when making determinations with respect to salaries, bonuses and long-term incentive awards. Unlike the discretionary cash bonus award described above, the GP Bonus Awards are paid by the general partner and not reimbursed by NRP. However, because the GP Bonus Awards represent compensation to executive officers related to services provided to NRP, they are recorded by NRP as general and administrative expenses and equity contributions from the general partner. Prior to 2015, we did not record the GP Bonus Awards cash compensation paid by the general partner as an expense.

The amounts received by the named executive officers under the GP Bonus Award program were significantly lower for 2016 as compared to 2015 due to the 87% reduction in the per unit distribution paid by NRP during the calendar year ended December 31, 2015. This decrease resulted in a decreased overall amount allocated to the executive officers. Mr. Robertson determined to allocate the GP Bonus Awards equally among our executive officers.

Long-Term Incentive Compensation

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

Our CNG Committee has historically approved annual awards of phantom units that vest four years from the date of grant. The amounts included in the compensation table reflect the grant date fair value of the unit awards determined in accordance with FASB stock compensation authoritative guidance. NRP bears 100% of the costs of the phantom units. We structured the phantom unit awards so that our executive officers and directors directly benefited along with our unitholders when our unit price increases, and experienced reductions in the value of their incentive awards when our unit price declined. Similarly, because the awards are forfeited by the executives upon termination of employment in most instances, the long-term vesting component of these awards encouraged our senior executives and employees to remain with NRP over an extended period of time, thereby ensuring continuity in our management team. Consistent with this approach, we included DERs as a possible award to be granted under the plan. The DERs are contingent rights, granted in tandem with phantom units, to receive upon vesting of the related phantom units an amount in cash equal to the cash distributions made by NRP with respect to the common units during the period in which the phantom units are outstanding.

As noted below, in light of then existing market conditions, the relative low value of NRP’s common units and the strategic plan to dedicate all free cash flow towards reducing NRP’s leverage, the CNG Committee determined that the phantom units and DERs awarded under the Long-Term Incentive Plan no longer held retentive value for NRP’s management team. As a result, the CNG Committee recommended, and the Board approved, the 2016 Cash Long-Term Incentive Plan described below.

2016 Cash Long-Term Incentive Plan

In February 2016, the CNG Committee adopted a new cash-based long-term incentive plan and recommended the new plan and awards thereunder to the non-management members of the Board for approval. The Board approved the new plan and the forms of long-term incentive award agreements in February 2016. Two types of cash incentive awards were made to the executive officers in March 2016: (1) time vesting awards, 50% of which vested in February 2017 and 50% of which will vest in February 2018, and (2) performance-based awards that provide that such awards vest 50% upon the repayment, refinancing or rollover of the Opco revolving credit facility that matures in April 2018 and 50% upon the repayment, refinancing or rollover of NRP’s 9.125% Senior Notes due October 2018, in each case as determined by the Board and depending upon the continued employment of the applicable executive officer. The performance awards also provide that up to an additional 100% of the amount of the performance-based awards may be awarded to the executive officers in the sole discretion of the Board after considering additional performance criteria including, but not limited to, NRP’s common unit price, projected EBITDA, and leverage ratio. The awards made in March 2016 to the named executive officers under the cash long-term incentive plan are as follows:

2016 Cash Incentive Awards

	Performance Award Grant Amount	Time Vesting Award Grant Amount (1)	Total Award Grant Amount	Total Maximum Payout Amount
Corbin J. Robertson, Jr. - Chairman and Chief Executive Officer	$ 1,500,000	$ 500,000	$ 2,000,000	$ 3,500,000
Wyatt L. Hogan - President and Chief Operating Officer	750,000	250,000	1,000,000	1,750,000
Craig W. Nunez - Chief Financial Officer and Treasurer	562,500	187,500	750,000	1,312,500
Kathryn S. Wilson - Vice President, General Counsel and Secretary	450,000	150,000	600,000	1,050,000
Christopher J. Zolas - Chief Accounting Officer	150,000	150,000	300,000	450,000

(1) One-half of each time vesting award granted in 2016 vested in 2017.

Following the completion of the March 2017 recapitalization transactions, on March 3, 2017, the Board determined that both vesting conditions of the performance awards had been met and therefore the target performance award grant amounts would be awarded to each executive officer. In addition, following consideration of additional performance criteria including, but not limited to: (1) the performance of NRP's common units over the past twelve months and subsequent to the announcement of the transactions; (2) the 2016 and projected 2017 EBITDA for NRP; and (3) the current and projected leverage ratios for NRP and its subsidiaries, the Board determined to award an additional 100% of the amount of the performance-based awards to the executive officers. The amounts that will be paid to the named executive officers will be equal to 200% of the performance award grant amounts shown in the table above. These amounts will be paid will be paid to the officers within 30 days of the date of the Board's determination.

Perquisites and Other Personal Benefits

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

Quintana and Western Pocahontas also maintain tax-qualified 401(k) and defined contribution retirement plans. Quintana matches 100% of the first 4.5% of the employee contributions under the 401(k) plan and Western Pocahontas matches the employee contributions at a level of 100% of the first 3% of the contribution and 50% of the next 3% of the contribution. In addition, each company contributes 1/12 of each employee's base salary to the defined contribution retirement plan on an annual basis. As with the other contributions, any amounts contributed by Quintana and Western Pocahontas are reimbursed by us based on the time allocated by the employee to our business. None of NRP, Quintana or Western Pocahontas maintains a pension plan or a defined benefit retirement plan.

Unit Ownership Requirements

We do not have any policy guidelines that require specified ownership of our common units by our directors or executive officers or unit retention guidelines applicable to equity-based awards granted to directors or executive officers. As of December 31, 2016, our named executive officers held 21,540 phantom units that have been granted as compensation. In addition, Mr. Robertson directly or indirectly owns in excess of 20% of the outstanding units of NRP.

Securities Trading Policy

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

Tax Implications of Executive Compensation

Because we are a partnership, Section 162(m) of the Internal Revenue Code does not apply to compensation paid to our named executive officers and accordingly, the CNG Committee did not consider its impact in determining compensation levels in 2014, 2015 or 2016. The CNG Committee has taken into account the tax implications to the partnership in its decision to limit the long-term incentive compensation to phantom units as opposed to options or restricted units.

Accounting Implications of Executive Compensation

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

Report of the Compensation, Nominating and Governance Committee

The CNG Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management. Based on the reviews and discussions referred to in the foregoing sentence, the CNG Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the year ended December 31, 2016.

Robert T. Blakely, Chairman
Russell D. Gordy
Robert B. Karn III
Leo A. Vecellio, Jr.

Summary Compensation Table

The following table sets forth the amounts reimbursed to affiliates of our general partner for compensation for 2014, 2015 and 2016 based on each individual's allocation of time to Natural Resource Partners:

Name and Principal Position [1]	Year	Salary	Cash Bonus	Phantom Unit Awards [2]	All Other Compensation[3]	Total
Corbin J. Robertson, Jr. - Chief Executive Officer	2016	$—	$—	$ —	$ —	$—
	2015	—	—	321,912	—	321,912
	2014	—	—	595,728	—	595,728
Wyatt L. Hogan - President and Chief Operating Officer	2016	$400,000	$450,000	$ —	$ 34,383	$884,383
	2015	400,000	400,000	160,956	33,783	994,739
	2014	377,654	225,000	186,165	33,336	822,155
Craig W. Nunez - Chief Financial Officer [4]	2016	$375,000	$425,000	$ —	$ 34,383	$834,383
	2015	375,000	375,000	446,575	33,783	1,230,358
Kathryn S. Wilson - Vice President, General Counsel and Secretary [5]	2016	$305,500	$225,000	$ —	$ 31,631	$562,131
	2015	315,250	175,000	84,949	33,413	608,612
	2014	291,375	100,000	121,007	30,869	543,251
Christopher J. Zolas - Chief Accounting Officer [4]	2016	$300,000	$200,000	$ —	$ 34,383	$534,383
	2015	244,932	150,000	239,295	30,858	665,085

(1) In 2016, Messrs. Robertson, Hogan, Nunez, Ms. Wilson and Mr. Zolas spent approximately 50%, 100%, 100%, 94% and 100%, respectively, of their time on NRP matters.

(2) Amounts represent the grant date fair value of phantom unit awards determined in accordance with Accounting Standards Codification Topic 718 determined without regard to forfeitures. For information regarding the assumptions used in calculating these amounts, see Note 16 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(3) Includes portions of 401(k) matching and retirement contributions allocated to Natural Resource Partners by Quintana.

(4) Messrs. Nunez and Zolas were not named executive officers for purposes of this Summary Compensation Table during 2014.

(5) Amounts for Ms. Wilson's base salary and all other compensation columns represent the amounts allocated to NRP.

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The following table sets forth the GP Bonus Awards paid by the general partner and not reimbursed by NRP as described above. These GP Bonus Award amounts are not included in the summary compensation table:

Name and Principal Position	Year	Amount
Corbin J. Robertson, Jr. - Chief Executive Officer	2016	$40,114
	2015	160,000
	2014	180,000
Wyatt L. Hogan - President and Chief Operating Officer	2016	$40,114
	2015	160,000
	2014	384,000
Craig W. Nunez - Chief Financial Officer	2016	$40,114
	2015	160,000
Kathryn S. Wilson - Vice President, General Counsel and Secretary	2016	$40,114
	2015	125,000
	2014	180,000
Christopher J. Zolas - Chief Accounting Officer	2016	$40,114
	2015	$52,000

Grants of Plan-Based Awards in 2016

The following table sets forth the cash incentive awards granted in 2016:

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)		
Named Executive Officer	Grant Date	Threshold	Target	Maximum
Corbin J. Robertson, Jr.	3/10/2016	$2,000,000	$2,000,000	$3,500,000
Wyatt L. Hogan	3/10/2016	1,000,000	1,000,000	1,750,000
Craig W. Nunez	3/10/2016	750,000	750,000	1,312,500
Kathryn S. Wilson	3/10/2016	600,000	600,000	1,050,000
Christopher J. Zolas	3/10/2016	300,000	300,000	450,000

(1) Amounts include both time-vesting and performance based awards granted under the 2016 cash long-term incentive plan detailed above. One-half or each time vesting award granted in 2016 vested in February 2017.

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

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

The CNG Committee may make grants under our long-term incentive plans to employees and directors containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of NRP, our general partner or GP Natural Resource Partners LLC. If a grantee's employment or membership on the Board terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the CNG Committee provides otherwise.

As stated above under "—Compensation Discussion and Analysis," we have no outstanding option grants, and do not intend to grant any options or restricted unit awards in the future. In addition, the CNG Committee determined to make cash long-term incentive awards in 2016 in lieu of phantom unit awards as described above under "—Compensation Discussion and Analysis—2016 Cash Long-Term Incentive Plan." The CNG Committee may determine to make additional awards of phantom units in the future.

Phantom Units Vested in 2016

The table below shows the phantom units that vested in 2016 with respect to each named executive officer, along with the phantom unit value realized by each individual:

Named Executive Officer	Phantom Units Vested in 2016 (1)	Value Realized on 2016 Vesting
Corbin J. Robertson, Jr.	3,200	$ 220,928
Wyatt L. Hogan	1,600	110,464
Craig W. Nunez	1,100	14,344
Kathryn S. Wilson	550	25,872
Christopher J. Zolas	600	7,824

(1) The unit numbers in the table above give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

Outstanding Equity Awards at December 31, 2016

The table below shows the total number of outstanding phantom units held by each named executive officer at December 31, 2016. The phantom units shown below were awarded in February 2013, 2014 and 2015, with a portion of the phantom units having vesting in February 2017 and the remaining portion vesting in each of 2018 and 2019.

Named Executive Officer	Unvested Phantom Units (1)		Market Value of Unvested Phantom Units (2)
Corbin J. Robertson, Jr.	10,160	(3)	$ 328,168
Wyatt L. Hogan	5,080	(4)	164,084
Craig W. Nunez	3,900	(5)	125,970
Kathryn S. Wilson	2,283	(6)	73,741
Christopher J. Zolas	2,400	(7)	77,520

(1) The unit numbers in the table above give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

(2) Based on a unit price of $32.30, the closing price for the common units on December 31, 2016.

(3) Includes 3,200 phantom units vested in February 2017, and 3,360 and 3,600 phantom units vesting in February 2018 and 2019, respectively.

(4) Includes 1,600 phantom units vested in February 2017, and 1,680 and 1,800 phantom units vesting in February 2018 and 2019, respectively.

(5) Includes 1,200 phantom units vested in February 2017, and 1,300 and 1,400 phantom units vesting in February 2018 and 2019, respectively.

(6)

Includes 650 phantom units vested in February 2017, and 683 and 950 phantom units vesting in February 2018 and 2019, respectively.

(7) Includes 650 phantom units vested in February 2017, and 800 and 950 phantom units vesting in February 2018 and 2019, respectively.

Potential Payments upon Termination or Change in Control

None of our executive officers have entered into employment agreements with Natural Resource Partners or its affiliates. Consequently, there are no severance benefits payable to any executive officer upon the termination of their employment. Upon the occurrence of a change in control of NRP, our general partner or GP Natural Resource Partners LLC, the outstanding phantom unit awards held by each of our executive officers would immediately vest. The table below indicates the impact of a change in control on (1) the outstanding cash awards under the 2016 Cash Long-Term Incentive Plan and (2) the outstanding equity-based awards at December 31, 2016, based on a unit price of $34.65, the 20-day average common unit price as of December 31, 2016, as required pursuant to the term of the phantom units.

	2016 Cash Long-Term Incentive Plan Awards		Phantom Unit Long-Term Incentive Awards				
Named Executive Officer	Time-Based Awards (1)	Performance-Based Awards (1)	Unvested Phantom Units (2)	Market Value of Unvested Phantom Units	Accumulated DERs	Total Potential Payments	
Corbin J. Robertson, Jr.	$500,000	$ 1,500,000	10,160	$351,993	$ 196,988	$2,548,981	
Wyatt L. Hogan	250,000	750,000	5,080	175,997	98,494	1,274,491	
Craig W. Nunez	187,500	562,500	3,900	135,116	15,795	900,911	(3)
Kathryn S. Wilson	150,000	450,000	2,283	79,095	40,908	720,003	
Christopher J. Zolas	150,000	150,000	2,400	83,148	9,720	392,868	(4)

(1) The outstanding awards vest 100% upon a change in control.

(2) The unit numbers in the table above give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

(3) Phantom units vested in 2017 and phantom units vesting in 2018 and 2019 include accrued DERs from February 11, 2015, the date of the grant of these units to Mr. Nunez.

(4) Phantom units vested in 2017 and phantom units vesting in 2018 and 2019 include accrued DERs from March 9, 2015, the date of the grant of these units to Mr. Zolas.

Directors' Compensation for the Year Ended December 31, 2016

The table below shows the directors' compensation for the year ended December 31, 2016. As with our named executive officers, we do not grant any options or restricted units to our directors:

Name of Director	Fees Earned or Paid in Cash (1)	Total (2)
Robert Blakely	$ 85,000	$85,000
Russell Gordy	65,000	65,000
Trey Jackson	43,022	43,022
Robert Karn III	85,000	85,000
S. Reed Morian	60,000	60,000
Richard Navarre	65,000	65,000
Corbin J. Robertson, III	60,000	60,000
Stephen Smith	80,000	80,000
Leo A. Vecellio, Jr.	65,000	65,000

(1) In 2016, the annual retainer for the directors was $60,000, and the directors did not receive any additional fees for attending meetings. Each chairman of a committee received an annual fee of $10,000 for serving as chairman, and each committee member received $5,000 for serving on a committee.

(2) No phantom unit awards were made to our directors in 2016. As of December 31, 2016, each director other than Mr. Jackson held 1,169 phantom units, of which 370 phantom units vested in February 2017, and 389 and 410 phantom units

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will vest in February 2018 and 2019, respectively. The awards amounts included in the foregoing sentence give effect to NRP’s one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

The table below shows the phantom units that vested in 2016 with respect to each Director, along with the value realized by each individual:

Director	Phantom Units Vested in 2016 [(1)]	Value Realized on 2016 Vesting
Robert Blakely	370	$ 25,545
Russell Gordy	370	12,336
Trey Jackson	—	—
Robert Karn III	370	25,545
S. Reed Morian	370	25,545
Richard Navarre	370	12,336
Corbin J. Robertson, III	370	14,371
Stephen Smith	370	25,545
Leo A. Vecellio, Jr.	370	25,545

(1) The unit numbers in the table above give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2016, Messrs. Blakely, Gordy, Karn and Vecellio served on the CNG Committee. None of Messrs. Blakely, Gordy, Karn or Vecellio has ever been an officer or employee of NRP or GP Natural Resource Partners LLC. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has any executive officer serving as a member of our Board or CNG Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth, as of March 2, 2017, the amount and percentage of our common units beneficially held by (1) each person known to us to beneficially own 5% or more of any class of our units, (2) by each of the directors and executive officers and (3) by all directors and executive officers as a group. Unless otherwise noted, each of the named persons and members of the group has sole voting and investment power with respect to the units shown. The information presented below gives effect to the one-for-ten reverse unit split that was effective on February 17, 2016.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)	
Corbin J. Robertson, Jr. (2)	4,128,605	33.8	%
Premium Resources LLC (3)	4,128,599	33.8	%
Wyatt L. Hogan (4)	1,250	*	
Craig W. Nunez	—	—	
Kevin J. Craig	1,800	*	
Kathy H. Roberts	2,000	*	
Kathryn S. Wilson	—	—	
Gregory F. Wooten	—	—	
Christopher J. Zolas	—	—	
Robert T. Blakely	2,500	*	
Russell D. Gordy(5)	7,000	*	
L.G. (Trey) Jackson III	—	—	
Robert B. Karn III	500	*	
Jasvinder S. Khaira	—	—	
S. Reed Morian	—	—	
Richard A. Navarre	1,000	*	
Corbin J. Robertson III (6)	172,790	1.4	%
Stephen P. Smith	355	*	
Leo A. Vecellio, Jr.	2,000	*	
Directors and Officers as a Group	4,319,550	35.3	%

*Less than one percent.

(1) Percentages based upon 12,232,006 common units issued and outstanding as of March 2, 2017. Unless otherwise noted, beneficial ownership is less than 1%.

(2) Mr. Robertson may be deemed to beneficially own the 4,128,599 common units owned by Premium Resources LLC. Mr. Robertson's address is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002.

(3) These common units may be deemed to be beneficially owned by Mr. Robertson. The address of Premium Resources LLC is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002.

(4) Of these common units, 50 common units are owned by the Anna Margaret Hogan 2002 Trust, 50 common units are owned by the Alice Elizabeth Hogan 2002 Trust, and 50 common units are held by the Ellen Catlett Hogan 2005 Trust. Mr. Hogan is a trustee of each of these trusts.

(5) Mr. Gordy may be deemed to beneficially own 5,000 common units owned by Minion Trail, Ltd. and 2,000 common units owned by Rock Creek Ranch 1, Ltd.

(6) Mr. Robertson may be deemed to beneficially own 9,783 common units held CIII Capital Management, LLC, 10,000 common units held by BHJ Investments, 5,046 common units held by The Corbin James Robertson III

2009 Family Trust and 39 common units held by his spouse, Brooke Robertson. The address for CIII Capital Management, LLC is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002, the address for BHJ Investments is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002 and the address for The Corbin James Robertson III 2009 Family Trust is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002. The following common units are pledged as collateral for loans: 29,542 common units owned directly by Mr. Robertson.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

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

Omnibus Agreement

Non-competition Provisions

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

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

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

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

- the GP affiliate was engaged in the restricted business at the closing of the offering; provided that if the fair market value of the asset or group of related assets of the restricted business subsequently exceeds $10 million, the GP affiliate must offer the restricted business to us under the offer procedures described below.
- the asset or group of related assets of the restricted business have a fair market value of $10 million or less; provided that if the fair market value of the assets of the restricted business subsequently exceeds $10 million, the GP affiliate must offer the restricted business to us under the offer procedures described below.
- the asset or group of related assets of the restricted business have a fair market value of more than $10 million and the general partner (with the approval of the conflicts committee) has elected not to cause us to purchase these assets under the procedures described below.
- its ownership in the restricted business consists solely of a non-controlling equity interest.

For purposes of this paragraph, "fair market value" means the fair market value as determined in good faith by the relevant GP affiliate.

The total fair market value in the good faith opinion of the WPP Group of all restricted businesses engaged in by the WPP Group, other than those engaged in by the WPP Group at closing of our initial public offering, may not exceed $75 million. For purposes of this restriction, the fair market value of any entity engaging in a restricted business purchased by the WPP Group will be determined based on the fair market value of the entity as a whole, without regard for any lesser ownership interest to be acquired.

If the WPP Group desires to acquire a restricted business or an entity that engages in a restricted business with a fair market value in excess of $10 million and the restricted business constitutes greater than 50% of the value of the business to be acquired, then the WPP Group must first offer us the opportunity to purchase the restricted business. If the WPP Group desires to acquire a restricted business or an entity that engages in a restricted business with a value in excess of $10 million and the restricted business constitutes 50% or less of the value of the business to be acquired, then the GP affiliate may purchase the restricted business first and then offer us the opportunity to purchase the restricted business within six months of acquisition. For purposes of this paragraph, "restricted business" excludes a general partner interest or managing member interest, which is addressed in a separate restriction summarized below. For purposes of this paragraph only, "fair market value" means the fair market value as determined in good faith by the relevant GP affiliate.

If we want to purchase the restricted business and the GP affiliate and the general partner, with the approval of the conflicts committee, agree on the fair market value and other terms of the offer within 60 days after the general partner receives the offer from the GP affiliate, we will purchase the restricted business as soon as commercially practicable. If the GP affiliate and the general partner, with the approval of the conflicts committee, are unable to agree in good faith on the fair market value and other terms of the offer within 60 days after the general partner receives the offer, then the GP affiliate may sell the restricted business to a third party within two years for no less than the purchase price and on terms no less favorable to the GP affiliate than last offered by us. During this two-year period, the GP affiliate may operate the restricted business in competition with us, subject to the restriction on total fair market value of restricted businesses owned in the case of the WPP Group.

If, at the end of the two year period, the restricted business has not been sold to a third party and the restricted business retains a value, in the good faith opinion of the relevant GP affiliate, in excess of $10 million, then the GP affiliate must reoffer the restricted business to the general partner. If the GP affiliate and the general partner, with the approval of the conflicts committee, agree on the fair market value and other terms of the offer within 60 days after the general partner receives the second offer from the GP affiliate, we will purchase the restricted business as soon as commercially practicable. If the GP Affiliate and the general partner, with the concurrence of the conflicts committee, again fail to agree after negotiation in good faith on the fair market value of the restricted business, then the GP affiliate will be under no further obligation to us with respect to the restricted business, subject to the restriction on total fair market value of restricted businesses owned.

In addition, if during the two-year period described above, a change occurs in the restricted business that, in the good faith opinion of the GP affiliate, affects the fair market value of the restricted business by more than 10 percent and the fair market value of the restricted business remains, in the good faith opinion of the relevant GP affiliate, in excess of $10 million, the GP affiliate will be obligated to reoffer the restricted business to the general partner at the new fair market value, and the offer procedures described above will recommence.

If the restricted business to be acquired is in the form of a general partner interest in a publicly held partnership or a managing member interest in a publicly held limited liability company, the WPP Group may not acquire such restricted business even if we decline to purchase the restricted business. If the restricted business to be acquired is in the form of a general partner interest in a non-publicly held partnership or a managing member of a non-publicly held limited liability company, the WPP Group may acquire such restricted business subject to the restriction on total fair market value of restricted businesses owned and the offer procedures described above.

The omnibus agreement may be amended at any time by the general partner, with the concurrence of the conflicts committee. The respective obligations of the WPP Group under the omnibus agreement terminate when the WPP Group and its affiliates cease to participate in the control of the general partner.

Board Representation and Observation Rights Agreement

Effective on March 2, 2017 in connection with the closing of the issuance of the Preferred Units, pursuant to the Board Representation and Observation Rights Agreement, Blackstone appointed Jasvinder S. Khaira to serve on the Board of Directors of GP Natural Resource Partners LLC and also appointed one observer to attend meetings of the Board. Blackstone's rights to appoint a member of the Board and an observer will terminate at such time as Blackstone, together with their affiliates, no longer own the Minimum Preferred Unit Threshold (as defined elsewhere in this Annual Report on Form 10-K). Following the time that Blackstone (and their affiliates) no longer own the Minimum Preferred Unit Threshold and until such time as GoldenTree (together with their affiliates) no longer own the Minimum Preferred Unit Threshold, GoldenTree shall have the one time option to appoint either one person to serve as a member of the Board or one person to serve as a Board observer. To the extent GoldenTree elects to appoint a Board member and later remove such Board member, GoldenTree may then elect to appoint a Board observer. The Board Representation and Observation Rights Agreement is filed as Exhibit 4.29 to this Annual Report on Form 10-K and herein incorporated by reference.

Restricted Business Contribution Agreement

In connection with our partnership with Christopher Cline and his affiliates, Mr. Cline, Foresight Reserves LP and Adena (collectively, the "Cline Parties") and NRP have executed a Restricted Business Contribution Agreement. Pursuant to the terms of the Restricted Business Contribution Agreement, the Cline Parties and their affiliates are obligated to offer to NRP any business owned, operated or invested in by the Cline Parties, subject to certain exceptions, that either (a) owns, leases or invests in hard minerals or (b) owns, operates, leases or invests in transportation infrastructure relating to future mine developments by the Cline Parties in Illinois. In addition, we created an area of mutual interest (the "AMI") around certain of the properties that we have acquired from Cline affiliates. During the applicable term of the Restricted Business Contribution Agreement, the Cline Parties will be obligated to contribute any coal reserves held or acquired by the Cline Parties or their affiliates within the AMI to us. In connection with the offer of mineral properties by the Cline Parties to NRP, the parties to the Restricted Business Contribution Agreement will negotiate and agree upon an area of mutual interest around such minerals, which will supplement and become a part of the AMI.

We have made several acquisitions from Cline affiliates pursuant to the Restricted Business Contribution Agreement. For a summary of revenues that we have derived from the Cline relationship, including Foresight Energy LP, see "Item 8. "Item 8. Financial Statements and Supplementary Data—Note 13. Related Party Transactions—Cline Affiliates" elsewhere in this Annual Report on Form 10-K.

Mr. Holcomb, who was appointed to the Board in October 2013 and resigned from the Board in April 2016, previously served as Chief Financial Officer for Foresight Reserves LP and its subsidiaries. Mr. Holcomb owned a less than 1% equity interest in certain Cline affiliates until March 2013 when he fully divested from all Cline affiliates. As a result of his position as an executive officer and an equity holder of certain Cline affiliates, Mr. Holcomb may be deemed to have had an indirect material interest in the transactions with the Cline affiliates described in this Annual Report on Form 10-K.

Mr. Holcomb is a manager of Cline Trust Company, LLC, which owns common units and 2018 Notes. 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.

Investor Rights Agreement

NRP and certain affiliates and Adena executed an Investor Rights Agreement pursuant to which Adena was granted certain management rights. Specifically, Adena has the right to name two directors (one of which must be independent) to the Board of Directors of our managing general partner so long as Adena beneficially owns either 5% of our limited partnership interest or 5% of our general partner’s limited partnership interest and so long as certain rights under our managing general partner’s LLC Agreement have not been exercised by Adena or Mr. Robertson. Leo A. Vecellio and L.G. (Trey) Jackson III currently serve as Adena’s two directors. Mr. Vecellio serves on our CNG Committee. Adena will also have the right, pursuant to the terms of the Investor Rights Agreement, to withhold its consent to the sale or other disposition of any entity or assets contributed by Cline affiliates to NRP, and any such sale or disposition will be void without Adena’s consent.

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. NRP's Board of Directors has 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 basic tenets of the policy are set forth below.

NRP's business strategy has historically focused on:

- The ownership of natural resource properties in North America, including, but not limited to coal, aggregates and industrial minerals, and oil and gas. NRP leases these properties to mining or operating companies that mine or produce the resources and pay NRP a royalty.
- The ownership and operation of transportation, storage and related logistics activities related to extracted hard minerals.

The businesses and investments described in this paragraph are referred to as the "NRP Businesses."
NRP's acquisition strategy also includes:

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- The ownership of non-operating working interests in oil and gas properties.
- The ownership of non-controlling equity interests in companies involved in natural resource development and extraction.
- The operation of construction aggregates mining and production businesses.

The businesses and investments described in this paragraph are referred to as the "Shared Businesses."

NRP's business strategy does not, and is not expected to, include:
- The ownership of equity interests in companies involved in the mining or extraction of coal.
- Investments that do not generate "qualifying income" for a publicly traded partnership under U.S. tax regulations.
- Investments outside of North America.
- Midstream or refining businesses that do not involve hard extracted minerals, including the gathering, processing, fractionation, refining, storage or transportation of oil, natural gas or natural gas liquids.

In addition, although NRP's current oil and gas strategy is focused on the acquisition of minerals, royalties and non-operated working interests, NRP may also consider the acquisition of operated interests. The businesses and investments described in this paragraph are referred to as the "Non-NRP Businesses."

It is acknowledged that neither Quintana Capital nor Mr. Robertson will have any obligation to offer investments relating to Non-NRP Businesses to NRP, and that NRP will not have any obligation to refrain from pursuing a Non-NRP Business if there is a change in its business strategy.

For so long as Corbin Robertson, Jr. remains both an affiliate of Quintana Capital and an executive officer or director of NRP or an affiliate of its general partner, before making an investment in an NRP Business, Quintana Capital has agreed to adhere to the following procedures:
- Quintana Capital will first offer such opportunity in its entirety to NRP. NRP may elect to pursue such investment wholly for its own account, to pursue the opportunity jointly with Quintana Capital or not to pursue such opportunity.
- If NRP elects not to pursue an NRP Business investment opportunity, Quintana Capital may pursue the investment for its own account on similar terms.
- NRP will undertake to advise Quintana Capital of its decision regarding a potential investment opportunity within 10 business days of the identification of such opportunity to the Conflicts Committee.

If the opportunity relates to the acquisition of a Shared Business, NRP and Quintana Capital will adhere to the following procedures:
- If the opportunity is generated by individuals other than Mr. Robertson, the opportunity will belong to the entity for which those individuals are working.
- If the opportunity is generated by Mr. Robertson and both NRP and Quintana Capital are interested in pursuing the opportunity, it is expected that the Conflicts Committee will work together with the relevant Limited Partner Advisory Committees for Quintana Capital to reach an equitable resolution of the conflict, which may involve investments by both parties.

In all cases above in which Mr. Robertson has a conflict of interest, investment decisions will be made on behalf of NRP by the Conflicts Committee and on behalf of Quintana Capital Group by the relevant Investment Committee, with Mr. Robertson abstaining.

A fund controlled by Quintana Capital owns an 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.

For more information on our relationship with Corsa Coal, see "Item 8. Financial Statements and Supplemetary Data—Note 13. Related Party Transactions—Quintana Capital Group GP, Ltd."

Office Building in Huntington, West Virginia

We lease an office building in Huntington, West Virginia from Western Pocahontas Properties Limited Partnership. The terms of the lease, including $0.6 million per year in lease payments, were approved by our conflicts committee.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including the WPP Group, the Cline entities, and their affiliates) on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of GP Natural Resource Partners LLC have duties to manage GP Natural Resource Partners LLC and our general partner in a manner beneficial to its owners. At the same time, our general partner has a duty to manage our partnership in a manner beneficial to us and our unitholders. The Delaware Revised Uniform Limited Partnership Act, which we refer to as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by a general partner to limited partners and the partnership. Pursuant to these provisions, our partnership agreement contains various provisions modifying the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of the general partner and the methods of resolving conflicts of interest. Our partnership agreement also specifically defines the remedies available to limited partners for actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and our partnership or any other partner, on the other, our general partner will resolve that conflict. Our general partner may, but is not required to, seek the approval of the conflicts committee of the Board of Directors of our general partner of such resolution. The partnership agreement contains provisions that allow our general partner to take into account the interests of other parties in addition to our interests when resolving conflicts of interest.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is considered to be fair and reasonable to us. Any resolution is considered to be fair and reasonable to us if that resolution is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval and our general partner may adopt a resolution or course of action that has not received approval;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In resolving a conflict, our general partner, including its conflicts committee, may, unless the resolution is specifically provided for in the partnership agreement, consider:

- the relative interests of any party to such conflict and the benefits and burdens relating to such interest;
- any customary or accepted industry practices or historical dealings with a particular person or entity;
- generally accepted accounting practices or principles; and
- such additional factors it determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

Conflicts of interest could arise in the situations described below, among others.

Actions taken by our general partner may affect the amount of cash available for distribution to unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;

- the issuance of additional common units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by our general partner to the unitholders, including borrowings that have the purpose or effect of enabling our general partner to receive distributions.

For example, in the event we have not generated sufficient cash from our operations to pay the quarterly distribution on our common units, our partnership agreement permits us to borrow funds which may enable us to make this distribution on all outstanding common units.

The partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us or our subsidiaries.

Excluding VantaCore, we do not have any officers or employees and rely solely on officers and employees of GP Natural Resource Partners LLC and its affiliates.

Excluding our VantaCore business, we do not have any officers or employees and rely solely on officers and employees of GP Natural Resource Partners LLC and its affiliates. Affiliates of GP Natural Resource Partners LLC conduct businesses and activities of their own in which we have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the officers and employees who provide services to our general partner. The officers of GP Natural Resource Partners LLC are not required to work full time on our affairs. These officers devote significant time to the affairs of the WPP Group or its affiliates and are compensated by these affiliates for the services rendered to them.

We reimburse our general partner and its affiliates for expenses.

We reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. The partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets, and not against our general partner or its assets. The partnership agreement provides that any action taken by our general partner to limit its liability or our liability is not a breach of our general partner’s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Common unitholders have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us on the one hand, and our general partner and its affiliates, on the other, do not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, are not the result of arm's-length negotiations.

The partnership agreement allows our general partner to pay itself or its affiliates for any services rendered to us, provided these services are rendered on terms that are fair and reasonable. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither the partnership agreement nor any of the other agreements, contracts and arrangements between us, on the one hand, and our general partner and its affiliates, on the other, are the result of arm's-length negotiations.

All of these transactions entered into after our initial public offerings are on terms that are fair and reasonable to us.

Our general partner and its affiliates have no obligation to permit us to use any facilities or assets of our general partner and its affiliates, except as may be provided in contracts entered into specifically dealing with that use. There is no obligation of our general partner or its affiliates to enter into any contracts of this kind.

We may not choose to retain separate counsel for ourselves or for the holders of common units.

The attorneys, independent auditors and others who have performed services for us in the past were retained by our general partner, its affiliates and us and have continued to be retained by our general partner, its affiliates and us. Attorneys, independent auditors and others who perform services for us are selected by our general partner or the conflicts committee and may also perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest arising between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases. Delaware case law has not definitively established the limits on the ability of a partnership agreement to restrict such fiduciary duties.

Our general partner's affiliates may compete with us.

The partnership agreement provides that our general partner is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. Except as provided in our partnership agreement, the Omnibus Agreement and the Restricted Business Contribution Agreement, affiliates of our general partner will not be prohibited from engaging in activities in which they compete directly with us.

As a result of the purchase of the Preferred Units, Blackstone has certain consent rights and board appointment and observation rights and may be deemed to be an affiliate of our general partner. In addition, GoldenTree has certain limited consent rights. In the exercise of these consent rights and board rights, conflicts of interest could arise between us and our general partner on the one hand, and Blackstone or GoldenTree on the other hand.

The Conflicts Committee Charter is available upon request.

Director Independence

For a discussion of the independence of the members of the Board of Directors of our managing general partner under applicable standards, see "Item 10. Directors and Executive Officers of the Managing General Partner and Corporate Governance—Corporate Governance—Independence of Directors," which is incorporated by reference into this Item 13.

Review, Approval or Ratification of Transactions with Related Persons

If a conflict or potential conflict of interest arises between our general partner and its affiliates (including the WPP Group, the Cline entities, Blackstone, GoldenTree, and their affiliates) on the one hand, and our partnership and our limited partners, on the other hand, the resolution of any such conflict or potential conflict is addressed as described under "—Conflicts of Interest."

Pursuant to our Code of Business Conduct and Ethics, conflicts of interest are prohibited as a matter of policy, except under guidelines approved by the Board and as provided in the Omnibus Agreement, the Restricted Business Contribution Agreement, and our partnership agreement. For the year ended December 31, 2016, there were no transactions where such guidelines were not followed.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit Committee of the Board of Directors of GP Natural Resource Partners LLC recommended and we engaged Ernst & Young LLP to audit our accounts and assist with tax work for fiscal 2016 and 2015. All of our audit, audit-related fees and tax services have been approved by the Audit Committee of our Board of Directors. The following table presents fees for professional services rendered by Ernst &Young LLP:

	2016	2015
Audit Fees(1)	$1,010,002	$1,192,306
Tax Fees(2)	746,463	773,005
All Other Fees(3)	1,980	2,400

(1) Audit fees include fees associated with the annual integrated audit of our consolidated financial statements and internal controls over financial reporting, separate audits of subsidiaries and reviews of our quarterly financial statement for inclusion

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in our Form 10-Q and comfort letters; consents; work related to acquisitions; assistance with and review of documents filed with the SEC.

(2) Tax fees include fees principally incurred for assistance with tax planning, compliance, tax return preparation and filing of Schedules K-1.

(3) All other fees include the subscription to EY Online research tool.

Audit and Non-Audit Services Pre-Approval Policy

I. Statement of Principles

Under the Sarbanes-Oxley Act of 2002 (the "Act"), the Audit Committee of the Board of Directors is responsible for the appointment, compensation and oversight of the work of the independent auditor. As part of this responsibility, the Audit Committee is required to pre-approve the audit and non-audit services performed by the independent auditor in order to assure that they do not impair the auditor’s independence from the Partnership. To implement these provisions of the Act, the SEC has issued rules specifying the types of services that an independent auditor may not provide to its audit client, as well as the audit committee’s administration of the engagement of the independent auditor. Accordingly, the Audit Committee has adopted, and the Board of Directors has ratified, this Audit and Non-Audit Services Pre-Approval Policy (the "Policy"), which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent auditor may be pre-approved.

The SEC’s rules establish two different approaches to pre-approving services, which the SEC considers to be equally valid. Proposed services may either be pre-approved without consideration of specific case-by-case services by the Audit Committee ("general pre-approval") or require the specific pre-approval of the Audit Committee ("specific pre-approval"). The Audit Committee believes that the combination of these two approaches in this Policy will result in an effective and efficient procedure to pre-approve services performed by the independent auditor. As set forth in this Policy, unless a type of service has received general pre-approval, it will require specific pre-approval by the Audit Committee if it is to be provided by the independent auditor. Any proposed services exceeding pre-approved cost levels or budgeted amounts will also require specific pre-approval by the Audit Committee.

For both types of pre-approval, the Audit Committee will consider whether such services are consistent with the SEC’s rules on auditor independence. The Audit Committee will also consider whether the independent auditor is best positioned to provide the most effective and efficient service for reasons such as its familiarity with our business, employees, culture, accounting systems, risk profile and other factors, and whether the service might enhance the Partnership’s ability to manage or control risk or improve audit quality. All such factors will be considered as a whole, and no one factor will necessarily be determinative.

The Audit Committee is also mindful of the relationship between fees for audit and non-audit services in deciding whether to pre-approve any such services and may determine, for each fiscal year, the appropriate ratio between the total amount of fees for audit, audit-related and tax services.

The appendices to this Policy describe the audit, audit-related and tax services that have the general pre-approval of the Audit Committee. The term of any general pre-approval is 12 months from the date of pre-approval, unless the Audit Committee considers a different period and states otherwise. The Audit Committee will annually review and pre-approve the services that may be provided by the independent auditor without obtaining specific pre-approval from the Audit Committee. The Audit Committee will add or subtract to the list of general pre-approved services from time to time, based on subsequent determinations.

The purpose of this Policy is to set forth the procedures by which the Audit Committee intends to fulfill its responsibilities. It does not delegate the Audit Committee's responsibilities to pre-approve services performed by the independent auditor to management.

Ernst & Young LLP, our independent auditor has reviewed this Policy and believes that implementation of the policy will not adversely affect its independence.

II. Delegation

As provided in the Act and the SEC's rules, the Audit Committee has delegated either type of pre-approval authority to Robert B. Karn III, the Chairman of the Audit Committee. Mr. Karn must report, for informational purposes only, any pre-approval decisions to the Audit Committee at its next scheduled meeting.

III. Audit Services

The annual Audit services engagement terms and fees will be subject to the specific pre-approval of the Audit Committee. Audit services include the annual financial statement audit (including required quarterly reviews), subsidiary audits and other procedures required to be performed by the independent auditor to be able to form an opinion on the Partnership's consolidated financial statements. These other procedures include information systems and procedural reviews and testing performed in order to understand and place reliance on the systems of internal control, and consultations relating to the audit or quarterly review. Audit services also include the attestation engagement for the independent auditor's report on management's report on internal controls for financial reporting. The Audit Committee monitors the audit services engagement as necessary, but not less than on a quarterly basis, and approves, if necessary, any changes in terms, conditions and fees resulting from changes in audit scope, partnership structure or other items.

In addition to the annual audit services engagement approved by the Audit Committee, the Audit Committee may grant general pre-approval to other audit services, which are those services that only the independent auditor reasonably can provide. Other audit services may include statutory audits or financial audits for our subsidiaries or our affiliates and services associated with SEC registration statements, periodic reports and other documents filed with the SEC or other documents issued in connection with securities offerings.

IV. Audit-related Services

Audit-related services are assurance and related services that are reasonably related to the performance of the audit or review of the Partnership's financial statements or that are traditionally performed by the independent auditor. Because the Audit Committee believes that the provision of audit-related services does not impair the independence of the auditor and is consistent with the SEC's rules on auditor independence, the Audit Committee may grant general pre-approval to audit-related services. Audit-related services include, among others, due diligence services pertaining to potential business acquisitions/dispositions; accounting consultations related to accounting, financial reporting or disclosure matters not classified as "Audit Services"; assistance with understanding and implementing new accounting and financial reporting guidance from rulemaking authorities; financial audits of employee benefit plans; agreed-upon or expanded audit procedures related to accounting and/or billing records required to respond to or comply with financial, accounting or regulatory reporting matters; and assistance with internal control reporting requirements.

V. Tax Services

The Audit Committee believes that the independent auditor can provide tax services to the Partnership such as tax compliance, tax planning and tax advice without impairing the auditor's independence, and the SEC has stated that the independent auditor may provide such services. Hence, the Audit Committee believes it may grant general pre-approval to those tax services that have historically been provided by the auditor, that the Audit Committee has reviewed and believes would not impair the independence of the auditor and that are consistent with the SEC's rules on auditor independence. The Audit Committee will not permit the retention of the independent auditor in connection with a transaction initially recommended by the independent auditor, the sole business purpose of which may be tax avoidance and the tax treatment of which may not be supported in the Internal Revenue Code and related regulations. The Audit Committee will consult with the Chief Financial Officer or outside counsel to determine that the tax planning and reporting positions are consistent with this Policy.

VI. Pre-Approval Fee Levels or Budgeted Amounts

Pre-approval fee levels or budgeted amounts for all services to be provided by the independent auditor will be established annually by the Audit Committee. Any proposed services exceeding these levels or amounts will require specific pre-approval by the Audit Committee. The Audit Committee is mindful of the overall relationship of fees for audit and non-audit services in determining whether to pre-approve any such services. For each fiscal year, the Audit Committee may determine the appropriate ratio between the total amount of fees for audit, audit-related and tax services.

VII. Procedures

All requests or applications for services to be provided by the independent auditor that do not require specific approval by the Audit Committee will be submitted to the Chief Financial Officer and must include a detailed description of the services to be rendered. The Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the Audit Committee. The Audit Committee will be informed on a timely basis of any such services rendered by the independent auditor.

Requests or applications to provide services that require specific approval by the Audit Committee will be submitted to the Audit Committee by both the independent auditor and the Chief Financial Officer, and must include a joint statement as to whether, in their view, the request or application is consistent with the SEC's rules on auditor independence.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (2) Financial Statements and Schedules

See "Item 8. Financial Statements and Supplementary Data."

(a)(3) Ciner Wyoming LLC Financial Statements

The financial statements of Ciner Wyoming LLC required pursuant to Rule 3-09 of Regulation S-X are included in this filing as Exhibit 99.1.

(a)(4) Exhibits

Exhibit Number	Description
2.1	Purchase Agreement, dated as of January 23, 2013, by and among Anadarko Holding Company, Big Island Trona Company, NRP Trona LLC and NRP (Operating) LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on January 25, 2013).
2.2	Agreement and Plan of Merger, dated as of August 18, 2014, by and among VantaCore Partners LP, VantaCore LLC, the Holders named therein, Natural Resource Partners L.P., NRP (Operating) LLC and Rubble Merger Sub, LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on August 20, 2014).
2.3	Interest Purchase Agreement, by and among NRP Oil and Gas LLC, Kaiser-Whiting, LLC and the Owners of Kaiser-Whiting, LLC dated as of October 5, 2014 (incorporated by reference to Current Report on Form 8-K filed on October 6, 2014).
2.4	Purchase and Sale Agreement dated as of June 13, 2016 by and between NRP Oil and Gas LLC and Lime Rock Resources IV-A, L.P.
3.1	Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of September 20, 2010 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on September 21, 2010).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of March 2, 2017 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on March 6, 2017).
3.3	Fifth Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of December 16, 2011 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on December 16, 2011).
3.4	Fifth Amended and Restated Limited Liability Company Agreement of GP Natural Resource Partners LLC, dated as of October 31, 2013 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on October 31, 2013).
3.5	Amended and Restated Limited Liability Company Agreement of NRP (Operating) LLC, dated as of October 17, 2002 (incorporated by reference to Exhibit 3.4 of Annual Report on Form 10-K for the year ended December 31, 2002).
3.6	Certificate of Limited Partnership of Natural Resource Partners L.P.(incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 filed April 19, 2002, File No. 333-86582).
4.1	Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the Purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed June 23,

	2003).
4.2	First Amendment, dated as of July 19, 2005, to Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed on July 20, 2005).
4.3	Second Amendment, dated as of March 28, 2007, to Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed on March 29, 2007).

Exhibit Number	Description
4.4	First Supplement to Note Purchase Agreement, dated as of July 19, 2005 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on July 20, 2005).
4.5	Second Supplement to Note Purchase Agreement, dated as of March 28, 2007 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 29, 2007).
4.6	Third Supplement to Note Purchase Agreement, dated as of March 25, 2009 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 26, 2009).
4.7	Fourth Supplement to Note Purchase Agreement, dated as of April 20, 2011 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on April 21, 2011).
4.8	Subsidiary Guarantee of Senior Notes of NRP (Operating) LLC, dated June 19, 2003 (incorporated by reference to Exhibit 4.5 to Current Report on Form 8-K filed June 23, 2003).
4.9	Form of Series A Note (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed June 23, 2003).
4.10	Form of Series B Note (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed June 23, 2003).
4.11	Form of Series D Note (incorporated by reference to Exhibit 4.12 to Annual Report on Form 10-K filed February 28, 2007).
4.12	Form of Series E Note (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed March 29, 2007).
4.13	Form of Series F Note (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed May 7, 2009).
4.14	Form of Series G Note (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed May 7, 2009).
4.15	Form of Series H Note (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed May 5, 2011).
4.16	Form of Series I Note (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed May 5, 2011).
4.17	Form of Series J Note (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 15, 2011).
4.18	Form of Series K Note (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on October 3, 2011).
4.19	Registration Rights Agreement, dated as of January 23, 2013, by and among Natural Resource Partners L.P. and the Investors named therein (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on January 25, 2013).
4.20	Indenture, dated September 18, 2013, by and among Natural Resource Partners L.P. and NRP Finance Corporation, as issuers, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 19, 2013).
4.21	Form of 9.125% Senior Notes due 2018 (contained in Exhibit 1 to Exhibit 4.20).
4.22	Third Amendment, dated as of June 16, 2015, to Note Purchase Agreements, dated as of June 19, 2003, among NRP (Operating) LLC and the holders named therein (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 18, 2015).

4.23	Fourth Amendment, dated as of September 9, 2016, to Note Purchase Agreements, dated as of June 19, 2003, among NRP (Operating) LLC and the holders named therein (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 12, 2016).
4.24	Indenture, dated March 2, 2017, by and among Natural Resource Partners L.P. and NRP Finance Corporation, as issuers, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed on March 6, 2017).
4.25	Form of 10.500% Senior Notes due 2018 (contained in Exhibit 1 to Exhibit 4.24).

Exhibit Number	Description
4.26	Registration Rights Agreement dated as of March 2, 2017, by and among Natural Resource Partners L.P., NRP Finance Corporation, and the Initial Notes Purchasers named therein (incorporated by reference to Exhibit 4.5 to Current Report on Form 8-K filed on March 6, 2017).
4.27	Registration Rights Agreement dated as of March 2, 2017, by and among Natural Resource Partners L.P. and the Purchasers named therein (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed on March 6, 2017).
4.28	Form of Warrant to Purchase Common Units (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 6, 2017).
10.1	Third Amended and Restated Credit Agreement, dated as of June 16, 2015, by and among NRP (Operating) LLC, the lenders party thereto, Citibank, N.A. as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc. and Wells Fargo Securities LLC as Joint Lead Arrangers and Joint Bookrunners, and Citibank, N.A., as Syndication Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on June 18, 2015).
10.2	First Amendment, dated as of June 3, 2016, to Third Amended and Restated Credit Agreement, dated as of June 16, 2015, by and among NRP (Operating) LLC, the lenders party thereto, Citibank, N.A. as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc. and Wells Fargo Securities LLC as Joint Lead Arrangers and Joint Bookrunners, and Citibank, N.A., as Syndication Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on June 7, 2016).
10.3	Contribution Agreement, dated as of September 20, 2010, by and among Natural Resource Partners L.P., NRP (GP) LP, Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation and NRP Investment L.P. (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on September 21, 2010).
10.4	First Amended and Restated Omnibus Agreement, dated as of April 22, 2009, by and among Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation, Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed May 7, 2009).
10.5	Restricted Business Contribution Agreement, dated January 4, 2007, by and among Christopher Cline, Foresight Reserves LP, Adena Minerals, LLC, GP Natural Resource Partners LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on January 4, 2007).
10.6	Investor Rights Agreement, dated January 4, 2007, by and among NRP (GP) LP, GP Natural Resource Partners LLC, Robertson Coal Management and Adena Minerals, LLC (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on January 4, 2007).
10.7	Waiver Agreement, dated November 12, 2009, by and among Natural Resource Partners L.P., Great Northern Properties Limited Partnership, Western Pocahontas Properties Limited Partnership, New Gauley Coal Corporation, Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on November 13, 2009).
10.8	Limited Liability Company Agreement of Ciner Wyoming LLC, dated June 30, 2014 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed by Ciner Resources LP on July 2, 2014).
10.9	Amendment No. 1 to the Limited Liabiltiy Company Agreement of Ciner Wyoming LLC dated November 5, 2015 (incorporated by reference to Exhibit 10.22 to Annual Report on Form 10-K filed by Ciner Resources LP on March 11, 2016).

10.10	Credit Agreement, dated as of August 12, 2013, among NRP Oil and Gas LLC, Wells Fargo Bank, N.A., as Administrative Agent, and Wells Fargo Securities, LLC as Sole Bookrunner and Sole Lead Arranger (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 13, 2013).
10.11	First Amendment to Credit Agreement, dated effective as of December 19, 2013, among NRP Oil and Gas LLC, Wells Fargo Bank, N.A., as Administrative Agent, and Wells Fargo Securities, LLC as Sole Bookrunner and Sole Lead Arranger (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on December 20, 2013).

Exhibit Number	Description
10.12	Second Amendment to Credit Agreement entered into effective as of November 12, 2014 among NRP Oil and Gas LLC, each of the Lenders that is a signatory thereto, and Wells Fargo Bank, N.A., as administrative agent for the Lenders (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on November 14, 2014).
10.13	Fourth Amendment to Credit Agreement entered into effective as of March 21, 2016 among NRP Oil and Gas LLC, each of the Lenders that is a signatory thereto, and Wells Fargo Bank, N.A., as administrative agent for the Lenders (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on March 22, 2016).
10.14	Second Amendment, dated as of March 2, 2017, to Third Amended and Restated Credit Agreement, dated as of June 16, 2015, by and among NRP (Operating) LLC, the lenders party thereto, Citibank, N.A. as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc. and Wells Fargo Securities LLC as Joint Lead Arrangers and Joint Bookrunners, and Citibank, N.A., as Syndication Agent (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed on March 6, 2017).
10.15	Preferred Unit and Warrant Purchase Agreement, dated as of February 22, 2017, by and among Natural Resource Partners L.P. and the Purchasers named therein (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on March 6, 2017.
10.16	Exchange and Purchase Agreement, dated as of February 22, 2017, by and among Natural Resource Partners L.P., NRP Finance Corporation and the Consenting Holders named therein (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K filed on March 6, 2017.
10.17	Board Representation and Observation Rights Agreement dated as of March 2, 2017, by and among Natural Resource Partners L.P., Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, BTO Carbon Holdings L.P. and the GoldenTree Purchasers named therein (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on March 6, 2017)
10.18***	Natural Resource Partners Second Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on January 17, 2008).
10.19***	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2007).
10.20***	Natural Resource Partners Annual Incentive Plan (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2002).
10.21***	Natural Resource Partners L.P. 2016 Cash Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on February 26, 2016).
10.22***	Form of Long-Term Incentive Award Agreement (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on February 26, 2016).
10.23***	Form of Long-Term Performance Award Agreement (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed on February 26, 2016).
21.1*	List of subsidiaries of Natural Resource Partners L.P.
23.1*	Consent of Ernst & Young LLP.

Exhibit Number	Description
23.2*	Consent of Deloitte & Touche LLP.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.
95.1*	Mine Safety Disclosure.
99.1*	Financial Statements of Ciner Wyoming LLC as of and for the years ended December 31, 2016, 2015 and 2014.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith
**	Furnished herewith
***	Management compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

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

Date: March 6, 2017

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

Date: March 6, 2017

By: /s/ CRAIG W. NUNEZ
Craig W. Nunez
Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: March 6, 2017

By: /s/ CHRISTOPHER J. ZOLAS
Christopher J. Zolas
Chief Accounting Officer
(Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: March 6, 2017

/s/ ROBERT T. BLAKELY
Robert T. Blakely
Director

Date: March 6, 2017

/s/ RUSSELL D. GORDY
Russell D. Gordy
Director

Date: March 6, 2017

L. G. (Trey) Jackson III
Director

Date: March 6, 2017

/s/ ROBERT B. KARN III
Robert B. Karn III
Director

Date: March 6, 2017

Jasvinder S. Khaira
Director

Date: March 6, 2017

/s/ S. REED MORIAN
S. Reed Morian
Director

Date: March 6, 2017

/s/ RICHARD A. NAVARRE
Richard A. Navarre
Director

Date: March 6, 2017

/s/ CORBIN J. ROBERTSON III
Corbin J. Robertson III
Director

Date: March 6, 2017

/s/ STEPHEN P. SMITH
Stephen P. Smith
Director

Date: March 6, 2017

/s/ LEO A. VECELLIO, JR.
Leo A. Vecellio, Jr.
Director