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.

	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.

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:

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:

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:

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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.

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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;

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- 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	$