NATURAL RESOURCE PARTNERS LP
Form 10-K
March 07, 2019

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, 2018 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 partner 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. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See definition of "accelerated filer", "large accelerated filer", "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer¨		Accelerated Filer	ý
Non-accelerated Filer ¨	(Do not check if a smaller reporting company)	Smaller Reporting Company	ý
		Emerging Growth Company	¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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, 2018, was $248 million based on a closing price on that date of $31.40 per unit as reported on the New York Stock Exchange.

As of March 1, 2019, there were 12,261,199 common units outstanding.

Documents incorporated by reference: None.

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CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

Statements included in this 10-K may constitute forward-looking statements. In addition, we and our representatives may from time to time make other oral or written statements which are also forward-looking statements. Such forward-looking statements include, among other things, statements regarding: our business strategy; our liquidity and access to capital and financing sources; our financial strategy; prices of and demand for coal, trona and soda ash, and other natural resources; estimated revenues, expenses and results of operations; projected production levels by our lessees; 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 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. NRP Finance Corporation ("NRP Finance") is a wholly owned subsidiary of NRP and a co-issuer with NRP on the 10.50% Senior Notes due 2022 (the "2022 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, manage and lease a diversified portfolio of mineral properties in the United States, including interests in coal, soda ash from trona and other natural resources.

Our business is organized into two operating segments:

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

Soda Ash—consists of our 49% non-controlling equity interest in Ciner Wyoming, a trona ore mining operation and soda ash refinery, in the Green River Basin of Wyoming. Ciner Resources, LP, our operating partner, mines the trona, processes it into soda ash and distributes the soda ash both domestically and internationally to the glass and chemicals industries.

In December 2018, we sold our construction aggregates business for $205 million, before customary purchase price adjustments and transaction expenses, and recorded a gain of $13.1 million. Our exit from the construction aggregates business enabled us to further reduce debt, focus on our Coal Royalty and Other and Soda Ash business segments and represented a strategic shift as we exited the operations of our construction aggregates business.

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 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, Jr. is entitled to appoint the members of the Board of Directors of GP Natural Resource Partners LLC and has delegated the right to appoint one director to Blackstone.

The senior executives and other officers who manage NRP are employees of Western Pocahontas Properties Limited Partnership or Quintana Minerals Corporation, which are companies controlled by Mr. Robertson, Jr. These officers 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.

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Segment and Geographic Information

The amount of 2018 revenue and other income from our two operating segments is shown below. For additional business segment information, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" and "Item 8. Financial Statements and Supplementary Data—Note 8. Segment Information" in this Annual Report on Form 10-K, which are both incorporated herein by reference.

(In thousands)	Amount	% of Total
Coal Royalty and Other	$230,206	83%
Soda Ash	48,306	17%
Total	$278,512	100%

Coal Royalty and Other Segment

Our coal reserves are primarily located in the Appalachia Basin, the Illinois Basin and the Northern Powder River Basin in the United States. We lease our reserves to experienced mine operators under long-term leases. Approximately two-thirds of our royalty-based leases have initial terms of five to 40 years, with substantially all lessees having the option to extend the lease for additional terms. Leases include the right to renegotiate royalties and minimum payments for the additional terms. We also own and manage coal-related transportation and processing assets that generate additional revenues generally based on throughput or rents in the Illinois Basin. As described in the "—Other Coal Royalty and Other Segment Assets" section below, we also own oil and gas, aggregates and industrial mineral reserves that generate a portion of Coal Royalty and Other segment revenues.

Under our standard royalty lease, we grant the operators the right to mine and sell our reserves in exchange for royalty payments based on the greater of a percentage of the sale price or fixed royalty per ton. 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 minimum payments, which reflect amounts we are entitled to receive even if no mining activity occurs during the period. Minimum payments are usually credited against future royalties that are earned as minerals are produced. In certain leases, the lessee is time limited on the period available for recouping minimum payments and such time is unlimited on other leases.

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 costs, black lung benefits and workers' compensation costs associated with operating the mines on our coal and aggregates properties. We 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 Reserves and Production Information

The following table presents coal reserves information as of December 31, 2018 for the properties that we own by major coal region:

	Proven and Probable Reserves (1)		
(Tons in thousands)	Underground	Surface	Total
Appalachia Basin			
Northern	366,633	2,934	369,567
Central	723,795	238,531	962,326
Southern	59,317	19,966	79,283
Total Appalachia Basin	1,149,745	261,431	1,411,176
Illinois Basin	302,002	5,074	307,076
Northern Powder River Basin	—	166,590	166,590
Gulf Coast	—	1,957	1,957
Total	1,451,747	435,052	1,886,799

(1) In excess of 94% of the reserves presented in this table are currently leased to third parties.

The following table presents the type of coal reserves by major coal region as of December 31, 2018:

	Type of Coal		
(Tons in thousands)	Thermal	Metallurgical (1)	Total
Appalachia Basin			
Northern	308,054	61,513	369,567
Central	541,625	420,701	962,326
Southern	58,957	20,326	79,283
Total Appalachia Basin	908,636	502,540	1,411,176
Illinois Basin	307,076	—	307,076
Northern Powder River Basin	166,590	—	166,590
Gulf Coast	1,875	82	1,957
Total	1,384,177	502,622	1,886,799

(1) For purposes of this table, we have defined metallurgical coal reserves as reserves located in 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 thermal coal.

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The following table presents the sulfur content and the typical quality of our coal reserves by major coal region as of December 31, 2018:

	Sulfur Content					Typical Quality (1)	
(Tons in thousands)	Compliance Coal (2)	Low (<1.0%)	Medium (1.0% to 1.5%)	High (>1.5%)	Total	Heat Content (Btu per pound)	Sulfur (%)
Appalachia Basin							
Northern	46,647	46,847	905	321,815	369,567	12,873	2.89
Central	453,122	671,508	244,489	46,329	962,326	13,232	0.90
Southern	44,903	49,518	27,175	2,590	79,283	13,408	0.96
Total Appalachia Basin	544,672	767,873	272,569	370,734	1,411,176	13,148	1.43
Illinois Basin	—	—	2,152	304,924	307,076	11,474	3.29
Northern Powder River Basin	—	166,590	—	—	166,590	8,800	0.65
Gulf Coast	82	1,957	—	—	1,957	6,964	0.69
Total	544,754	936,420	274,721	675,658	1,886,799		

(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 moisture values for Illinois (typically 12% moisture) and Northern Powder River Basin (typically 25% moisture).

(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.

Methodologies Used in Mineral Reserve Estimation

All of the reserves reported above are recoverable proven or probable reserves as determined by the SEC's Industry Guide 7 and are estimated by our internal reserve geologist or independent third party consultants. Significant internally generated reserve studies are reviewed by independent third party consultants. The technologies and economic data used in the estimation of our proven 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."

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The following table presents the type of coal production by major coal region for the year ended December 31, 2018:

(Tons in thousands)	Type of Coal Thermal	Metallurgical	Total
Appalachia Basin			
Northern	2,152	1,035	3,187
Central	2,986	12,011	14,997
Southern	284	1,426	1,710
Total Appalachia Basin	5,422	14,472	19,894
Illinois Basin	2,739	—	2,739
Northern Powder River Basin	4,313	—	4,313
Total	12,474	14,472	26,946

Major Coal Producing Properties

The following table provides a summary of our major coal royalty properties and is followed by additional information for each property or lease name:

Region	Property/Lease Name	Operator	Coal Type	2018 Production (Millions of Tons)
Appalachia Basin				
Northern	Hibbs Run	Murray Energy Corporation	Thermal	1.5
Northern	Mettiki Coal	Alliance Resource Partners	Met/Thermal	1.1
Northern	Carter Roag	Metinvest	Met	0.4
Central	Contura-CAPP (VA)	Contura Energy, Inc.	Met	3.3
Central	Blackjewel-Lynch	Blackjewel LLC	Met/Thermal	2.3
Central	Coal Mountain	CM Energy Properties, LP and Ramaco Resources, Inc.	Met/Thermal	2.2
Central	Aracoma	Contura Energy, Inc.	Met/Thermal	1.7
Central	Pinnacle (1)	Mission Coal, LLC (2)	Met	1.1
Central	Kepler	Contura Energy, Inc.	Met	0.5
Central	Greenbrier Minerals	Coronado Coal	Met	0.4
Central	South Fork Coal	Xinergy Corp.	Met	0.2
Southern	Oak Grove	Mission Coal, LLC (2)	Met	1.4
Illinois Basin	Macoupin	Foresight Energy LP	Thermal	2.0
Illinois Basin	Williamson	Foresight Energy LP	Thermal	0.4
Illinois Basin	Hillsboro	Foresight Energy LP	Thermal	—
Northern Powder River Basin	Western Energy	Westmoreland Coal Company (2)	Thermal	4.3

(1) Pinnacle property is currently closed and not producing.
(2) Operator currently in bankruptcy.

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Appalachia Basin—Northern Appalachia

Hibbs Run. The Hibbs Run property is located in Marion County, West Virginia. In 2018, approximately 1.5 million tons were produced from this thermal property. We lease this property to a subsidiary of Murray Energy Corporation. Coal from this property is produced from longwall mines and shipped by rail to utility customers. The royalty rate for this property is a low fixed rate per ton and has a significant effect on the weighted average per ton revenue for the region.

Mettiki Coal. The Mettiki Coal property is located in Tucker and Grant Counties, West Virginia. In 2018, approximately 1.1 million tons metallurgical and thermal tons were produced from this property. We lease this property to a subsidiary of Alliance Resource Partners. Production comes from this mine via a longwall operation. Coal is shipped by truck to a local utility customer and by train to metallurgical customers. NRP pays an override royalty equal to the royalty received from Mettiki to Western Pocahontas Properties Limited Partnership per the terms of the deed.

Carter Roag. The Carter Roag property is located in Randolph and Upshur Counties, West Virginia. In 2018, approximately 0.4 million tons were produced from this metallurgical coal property. We lease this property to a subsidiary of Metinvest. Production comes from the Morgan Camp and Pleasant Hill room and pillar deep mines. The coal production 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 Ukraine.

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

Appalachia Basin—Central Appalachia

Contura-CAPP (VA). The Contura-CAPP (VA) property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2018, approximately 3.3 million tons were produced from this property, substantially all of which was metallurgical coal. We lease this property to subsidiaries of Contura Energy, Inc ("Contura Energy"). Production that comes from underground room and pillar and surface mines is trucked to one of two preparation plants. Coal is shipped via the CSX and Norfolk Southern railroads to utility and metallurgical customers.

Blackjewel-Lynch. The Blackjewel-Lynch (previously referred to as Resource Development) property is located in Harlan and Letcher Counties, Kentucky and Wise County, Virginia. In 2018, approximately 2.3 million tons of metallurgical and thermal coal were produced from this property. We lease this property to Blackjewel, LLC. Production comes from underground room and pillar and surface mines. This property has the ability to ship coal on the CSX and Norfolk Southern railroads to utility and metallurgical customers.

Coal Mountain. The Coal Mountain property is located in Wyoming County, West Virginia. In 2018, approximately 2.2 million tons of metallurgical coal were produced from the property. We lease this property to CM Energy Properties, LP and Ramaco Resources Inc. Metallurgical coal is produced from surface mining and metallurgical and thermal coal are produced from underground room and pillar mines and trucked to preparation plants on the property. Coal is shipped via the Norfolk Southern and CSX railroad to various utility customers and both domestic or export metallurgical customers.

Aracoma. The Aracoma property is located in Logan County, West Virginia. In November 2018, Alpha Natural Resources, Inc. (the former controlling company of the property) merged into Contura Energy. This property is now leased to a subsidiary of Contura Energy. Approximately 1.7 million tons of coal, substantially all of which is metallurgical coal, was produced in 2018 from the property. Coal is produced from underground room and pillar mines and transported by belt or truck to the preparation plant on the property. Coal is shipped via the CSX railroad to utility customers and to various domestic and export metallurgical customers.

Pinnacle. The Pinnacle property is located in Wyoming and McDowell Counties, West Virginia. In 2018, approximately 1.1 million tons of metallurgical coal was produced from our reserves on this property. We lease the property to a subsidiary of Mission Coal, LLC ("Mission Coal"), which filed for bankruptcy protection in 2018. Production came from a longwall mine and was transported by beltline to a preparation plant on the property. Coal was shipped via Norfolk Southern railroad to both domestic and export customers. The Pinnacle mine is currently closed and the preparation plant is idled.

Kepler. The Kepler property is located in Wyoming County, West Virginia. In 2018, approximately 0.5 million tons were produced from the property. We lease this property to a subsidiary of Contura Energy. In November 2018, Alpha Natural Resources, Inc. (the former controlling company of the property) merged into Contura Energy. Metallurgical coal is produced from two underground room and pillar 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.

Greenbrier Minerals. The Greenbrier Minerals property is located in Greenbrier County, West Virginia. In 2018, approximately 0.4 million tons were produced from the property. This property is leased to Coronado Coal. Metallurgical coal is produced from surface mines and transported by truck to a preparation plant. Coal is shipped via the CSX railroad to various export metallurgical customers.

South Fork Coal. The South Fork Coal property is located in Greenbrier County, West Virginia. In 2018, approximately 0.2 million tons were produced from the property. This property is leased to South Fork Coal Company, LLC, a subsidiary of Xinergy Corp. Metallurgical coal is produced from surface mines and transported by truck to a preparation plant. Coal is shipped via the CSX railroad to export metallurgical customers.

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

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Appalachia Basin—Southern Appalachia

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2018, approximately 1.4 million tons of metallurgical coal were produced from this property. We lease the property to a subsidiary of Mission Coal. Mission Coal filed for bankruptcy protection during 2018. Production comes from a longwall mine and is transported primarily by beltline to a preparation plant. Metallurgical coal is then shipped via railroad and barge to both domestic and export customers.

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

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Illinois Basin

Macoupin. The Macoupin property is located in Macoupin County, Illinois. The property is under lease to Macoupin Energy, a subsidiary of Foresight Energy LP ("Foresight Energy"). In 2018, approximately 2.0 million tons of thermal coal were sold from our property. Production is from an underground room and pillar mine. Coal is shipped via the Norfolk Southern or Union Pacific railroads or by barge to domestic utility or export customers.

Williamson. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to Williamson Energy, a subsidiary of Foresight Energy. In 2018, approximately 0.4 million tons of thermal coal were sold from our property. Production comes from a longwall mine. Coal is shipped primarily via the Canadian National railroad to domestic utility customers. Approximately 6.1 million tons of additional production was received in 2018 in the form of override royalty from an adverse property.

Hillsboro. The Hillsboro property is located in Montgomery and Bond Counties, Illinois. The property is under lease to Hillsboro Energy, a subsidiary of Foresight Energy. It had been idled since March 2015 until longwall panel development production resumed in January 2019. When fully active, production at the mine has historically come from longwall mining methods. Coal is shipped by rail via either the Union Pacific, Norfolk Southern or Canadian National railroads, or by barges to domestic utilities or export customers.

In addition to these properties, we own loadout and other transportation assets at the Williamson and Macoupin mines and at the Sugar Camp mines, which is also operated by Foresight Energy. See "—Coal Transportation and Processing Assets" below for additional information on these assets.

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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 2018, approximately 4.3 million tons were produced from our property by a subsidiary of Westmoreland Coal Company. Coal is produced by surface dragline mining methods, and the coal is transported by either truck or beltline to the Colstrip generation station located at the mine mouth. Westmoreland Coal Company filed for bankruptcy protection during 2018.

The map below shows the location of our property in the Northern Powder River Basin:

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Coal Transportation and Processing Assets

We own transportation and processing infrastructure related to certain of our coal properties, including loadout and other transportation assets at Foresight Energy's Williamson and Macoupin mines in the Illinois Basin, for which we collect throughput fees or rents. We lease our Macoupin and Williamson transportation and processing infrastructure to subsidiaries of Foresight Energy and are responsible for operating and maintaining the transportation and processing assets at the Williamson mine that we subcontract to a subsidiary of Foresight Energy. 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. While we own coal reserves at the Williamson and Macoupin mines, we do not own coal reserves at the Sugar Camp mine. The infrastructure at the Sugar Camp mine is leased to a subsidiary of Foresight Energy and we collect throughput fees. We recorded $23.9 million in revenue related to our coal transportation and processing assets during the year ended December 31, 2018.

Other Coal Royalty and Other Segment Assets

As of December 31, 2018, we owned an estimated 173 million tons of aggregates reserves primarily located in Kentucky and Indiana. We lease a portion of these reserves to third parties in exchange for royalty payments. The structure of these leases is similar to our coal leases, and these leases typically require minimum rental payments in addition to royalties. In addition, we hold overriding royalty interests in frac sand operations in Wisconsin and Texas and an overriding royalty interest in approximately 82 million tons of sand and gravel reserves in Washington. During 2018, our lessees produced 4.3 million tons from these properties and we received $4.7 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 natural gas mineral rights primarily in Louisiana, of which over 53,000 acres were leased as of December 31, 2018;
- approximately 50 million tons of aggregates reserves primarily located in North Carolina, Arkansas and South Carolina and approximately 6 million tons of override royalty interest in South Carolina and Georgia;
- approximately 95,000 net mineral acres of coal rights (primarily lignite and some bituminous coal) in the Gulf Coast region, of which approximately 5,600 acres are leased in Louisiana, Mississippi and Texas;
- an overriding royalty interest of 1% (net) 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 owned by BRP remain largely undeveloped, BRP has an ongoing program to identify additional opportunities to lease its minerals to operating parties or otherwise monetize these assets.

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Soda Ash Segment

We own a 49% non-controlling equity interest in Ciner Wyoming. Ciner Resources LP, our operating partner, controls and operates Ciner Wyoming. Ciner Resources LP mines the trona, processes it into soda ash, and distributes the soda ash both domestically and internationally into the glass and chemicals industries. Ciner Resources LP is a publicly traded master limited partnership that depends on distributions from Ciner Wyoming in order to make distributions to its public unitholders.

Ciner Wyoming 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 seven large continuous mining machines and 14 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.

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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 56 years.

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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. The 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 of the production process. This process enables Ciner Wyoming to reduce waste storage needs and convert what is typically a waste product into a usable raw material. Ciner Wyoming anticipates that its current deca stockpiles will be exhausted by 2023. In order to replace the volumes of soda ash produced from the deca rehydration process following exhaustion of those stockpiles, Ciner Wyoming will need to make significant capital expenditures over the next few years. See "Item 1A. Risk Factors—Risks Related to Our Business—We anticipate that Ciner Wyoming will need to increase capital expenditures in order to replace volumes of soda ash currently produced from the deca rehydration process, which could adversely affect Ciner Wyoming's profitability and ability to make cash distributions to us."

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, 2018, Ciner Wyoming shipped approximately 93.5% of its soda ash to its customers initially via a single rail line owned and controlled by Union Pacific Railroad Company ("Union Pacific"). The Ciner Wyoming plant receives rail service exclusively from Union Pacific. The agreement with Union Pacific expires on December 31, 2019 and there can be no assurance that it will be renewed on terms favorable to Ciner Wyoming or at all. The rail freight rate charged under the agreement increases annually based on a published index tied to certain rail industry metrics. Ciner Resources Corporation 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") currently 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 customers, including end users to whom ANSAC makes sales overseas, consist primarily of glass manufacturing companies, which account for 50% or more of the consumption of soda ash around the world; and chemical and detergent manufacturing companies. Ciner Wyoming's largest customer currently is ANSAC, which buys soda ash (through Ciner Resources Corporation, which serves as Ciner Wyoming's sales agent in its agreement with ANSAC) and other of its member companies for export to its customers. ANSAC accounted for approximately 52% of Ciner Wyoming's net sales in 2018. 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. During 2017, international sales were made through ANSAC as well as to affiliates of Ciner Resources Corporation.

In November 2018, Ciner Resources Corporation delivered a notice to terminate the membership in ANSAC, which is expected to be effective as of December 31, 2021. Until the effective termination date, ANSAC will continue to sell Ciner Wyoming's soda ash to ANSAC-designated overseas territories and continue to provide logistics and support services for Ciner Wyoming's other export sales. After the termination period, Ciner Resources Corporation will begin marketing soda ash directly into international markets which are currently being served by ANSAC, and Ciner Wyoming intends to utilize the distribution network that has already been established by the global Ciner Group. The

ANSAC agreement provides that in the event an ANSAC member exits or the ANSAC cooperative is dissolved, the exiting members are obligated for their respective portion of the residual net assets or deficit of the cooperative.

For customers in North America, Ciner Resources typically enters into contracts on Ciner Wyoming's behalf with terms ranging from one to three years. Under these contracts, customers generally agree to purchase either minimum estimated volumes of soda ash or a certain percentage of their soda ash requirements at a fixed price for a given calendar year. Although Ciner Wyoming does not have a "take or pay" arrangements with its customers, substantially all sales are made pursuant to written agreements and not through spot sales. In 2018, Ciner Wyoming had more than 70 domestic customers and has had long-term relationships with the majority of its customers.

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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.

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.

Significant Customers

We have a significant concentration of revenues with Foresight Energy and its subsidiaries, with total revenues of $54.6 million in 2018 from four different mining operations, including transportation and processing services, coal override and wheelage revenues. For additional information on significant customers, refer to "Item 8. Financial Statements and Supplementary Data—Note 16. Major Customers."

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, wind, solar and hydroelectric power.
Ciner Wyoming's trona mining and soda ash refinery business 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 substantially all of our coal and aggregates reserves in fee as of December 31, 2018. We lease the remainder from unaffiliated third parties. Ciner Wyoming 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 thermal 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 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 began 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 (CPP) 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. As promulgated, the rule would 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, likely resulting in a material adverse effect on the demand for coal by electric power generators. The rule 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 CPP Rule pending a decision by the District of Columbia Circuit as well as any subsequent review by the Supreme Court. In April 2017, the United States Court of Appeals for the District of Columbia Circuit granted EPA's motion to hold the litigation in abeyance. In December 2017, EPA issued a proposed rule repealing the CPP Rule and issued an Advance Notice of Proposed Rulemaking soliciting information regarding a potential replacement rule to the CPP Rule. In August 2018, EPA formally proposed the Affordable Clean Energy (ACE) Rule, which would replace the CPP Rule. The ACE Rule contemplates a narrower approach than the CPP Rule, focusing on efficiency improvements at existing power plants and eliminating the CPP Rule's broader goals that envisioned switches to non-fossil fuel energy sources and the implementation of efficiency measures on demand-side entities, which the EPA now considers beyond the reach of its authority under the Clean Air Act. The ACE Rule would also omit specific numerical emissions targets that had been established under the CPP Rule.

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. In April 2017, the court granted EPA's motion to hold the litigation in abeyance while EPA reviews the rule.

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. President Trump has expressed a desire for the United States to withdraw from the Paris Climate Agreement or to re-negotiate its terms.

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 Ciner Wyoming's soda ash businesses.

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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 was challenged by a number of states and private parties in federal district and circuit courts, and the rule was stayed on a nationwide basis by the Sixth Circuit Court of Appeals in October 2015. In January 2018, the United States Supreme Court ruled that challenges to the WOTUS rule are properly within the jurisdiction of the federal district courts rather than the Sixth Circuit or other federal appellate courts. In light of the Supreme Court's ruling, the Sixth Circuit lifted the nationwide stay. In February 2018, EPA and the Corps promulgated a rule delaying implementation of the 2015 WOTUS rule until 2020 and reinstating the regulatory definition of "Waters of the United States" that applied prior to the 2015 rule. Several federal district courts have enjoined the suspension rule, resulting in two different regulatory standards for determining the scope of jurisdiction under the Clean Water Act. Currently, the 2015 WOTUS rule is in effect in twenty-two states and Washington, D.C., while its predecessor remains in effect in the other twenty-eight. In December 2017, EPA and the Corps proposed a rule to repeal the WOTUS rule. In December 2018, EPA and the Corps issued a proposed rule revising the definition of "Waters of the United States." 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 its review of permits, EPA has at times 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. 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. 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.

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Other Regulations Affecting the Mining Industry

Mine Health and Safety Laws

The operations of our coal lessees 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.

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.

Employees and Labor Relations

As of December 31, 2018, affiliates of our general partner employed 57 people who directly supported our operations. None of these employees were subject to a collective bargaining agreement.

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Website Access to Partnership 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. Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information filed by us.

Corporate Governance Matters

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 are available on our website at www.nrplp.com. 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 to our principal executive office at 1201 Louisiana St., Suite 3400, Houston, Texas 77002.

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ITEM 1A. RISK FACTORS

Risks Related to Our Business

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves. In addition, our debt agreements and our partnership agreement place restrictions on our ability to pay, and in some cases raise, 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. 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. 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. We 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, our unitholders may be required to pay taxes in excess of any future distributions we make. Our unitholders' share of our portfolio income may be taxable to them even though they receive other losses from our activities. See "—Tax Risks to Our Unitholders—Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us. Our unitholders' share of our portfolio income may be taxable to them even though they receive other losses from our activities."

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 of $0.45 per common unit per quarter. 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 "Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and "Item 8. Financial Statements and Supplementary Data—Note 13. Debt, Net."

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

As of December 31, 2018, we and our subsidiaries had approximately $687.1 million of total indebtedness. The terms and conditions governing the indenture for NRP’s 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, including higher interest rates. We are required to make substantial principal repayments each year in connection with Opco's senior notes, with approximately $67 million due thereunder during 2019. In addition, Opco's revolving credit facility matures in April 2020. To the extent we borrow to make some of these payments, 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.

Prices for both metallurgical and thermal coal are volatile and depend on a number of factors beyond our control. Declines in prices could have a material adverse effect on our business and results of operations.

Coal prices continue to be volatile and prices could decline substantially from current levels. Production by some of our lessees may not be economic if prices decline further or remain at current levels. 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;
- global and domestic demand for steel;
- tariff rates on imports and trade disputes, particularly involving the United States and China;
- the availability of, proximity to and capacity of transportation networks and facilities;
- weather conditions; and
- the effect of worldwide energy conservation measures.

Natural gas is the primary fuel that competes with thermal coal for power generation, and renewable energy sources continue to gain market share in power generation. The abundance and ready availability of cheap natural gas, together with increased governmental regulations on the power generation industry has caused a number of utilities to switch from thermal coal to natural gas and/or close coal-powered generation plants. This switching has resulted in a decline in thermal coal prices, and to the extent that natural gas prices remain low, thermal coal prices will also remain low. Reduced international demand for export thermal coal, principally into India and northern Europe, has also put downward pressure on thermal coal prices.

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Our lessees produce a significant amount of metallurgical coal that is used for steel production domestically and internationally. Since the amount of steel that is produced is tied to global economic conditions, declines in those conditions could result in the decline of steel, coke and metallurgical coal production. Since metallurgical coal is priced higher than thermal 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. Any potential future lessee bankruptcy filings could 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.

To the extent our lessees are unable to economically produce coal over the long term, the carrying value of our reserves could be adversely affected. 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 or increases in costs of the production from our properties may reduce our revenues. The level of production and costs thereof are subject to operating conditions or events beyond our or our lessees' control including:

- difficulties or delays in acquiring necessary permits or mining or surface rights;
- reclamation costs and bonding costs;
- changes or variations in geologic conditions, such as the thickness of the mineral deposits and the amount of rock embedded in or overlying the mineral 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 networks and facilities and interruptions due to transportation delays;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions and trained personnel shortages; and
- mine safety incidents or accidents, including hazardous conditions, roof falls, fires and explosions.

While our lessees maintain insurance coverage, there is no assurance that insurance will be available or cover the costs of these risks. Many of our lessees are experiencing rising costs related to regulatory compliance, permitting and bonding, transportation, and labor. Increased costs result in decreased profitability for our lessees and reduce the competitiveness of coal as a fuel source. In addition, we and our lessees may also incur costs and liabilities resulting from third-party claims for damages to property or injury to persons arising from their operations. The occurrence of any of these events or conditions could have a material adverse effect on our business and results of operations.

The adoption of climate change legislation and regulations restricting emissions of greenhouse gases and other hazardous air pollutants have resulted in changes in fuel consumption patterns by electric power generators and a corresponding decrease in coal production by our lessees and reduced coal-related revenues.

Enactment of laws and passage of regulations regarding emissions from the combustion of coal by the U.S., some of its states or other countries, or other actions to limit such emissions, have resulted in and could continue to result in electricity generators switching from coal to other fuel sources and in coal-fueled power plant closures. Further, regulations regarding new coal-fueled power plants could adversely impact the global demand for coal. The potential financial impact on us of existing and future laws, regulations or other policies will depend upon the degree to which any such laws or regulations force electricity generators to diminish their reliance on coal as a fuel source. 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 Clean Power Plan and 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 existing 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.

In addition to EPA's greenhouse gas 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. For more information on regulation of greenhouse gas and other air pollutant emissions, see "Items 1. and 2. Business and Properties—Regulation and Environmental Matters."

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are also resulting in unfavorable lending and investment policies by institutions, which could significantly affect our ability to raise capital.

Global climate issues continue to attract public and scientific attention. Numerous reports have engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In addition to government regulation of greenhouse gas and other air pollutant emissions, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuels, such as coal. The impact of such efforts may adversely affect our ability to raise capital.

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 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. 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 mining 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. Under SMCRA, our coal lessees have substantial reclamation obligations on properties where mining operations have been completed and are required to post performance bonds for their reclamation obligations. To the extent an operator is unable to satisfy its reclamation obligations or the performance bonds posted are not sufficient to cover those obligations, regulatory authorities or citizens groups could attempt to shift reclamation liability onto the ultimate landowner, which if successful, could have a material adverse effect on our financial condition.

In addition to governmental regulation, private citizens' groups have continued to be active in bringing lawsuits against coal mine operators and land owners that allege violations of water quality standards resulting from ongoing discharges of pollutants from reclaimed mining operations, including selenium and conductivity. 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.

An adverse outcome in our contingent consideration payment dispute with Anadarko could have an adverse effect on our business and liquidity.

In July 2017, Anadarko Holding Company and its subsidiary, Big Island Trona Company (together, "Anadarko") filed a lawsuit against Opco and NRP Trona LLC alleging that a July 2013 simplification of OCI Wyoming's ownership structure triggered an acceleration of an obligation under the purchase agreement with Anadarko to pay additional contingent consideration in full and demanded immediate payment of such amount, together with interest, court costs and attorneys' fees. We would be required to pay up to $40 million, plus interest, court costs and attorneys' fees if Anadarko prevails and is awarded the full damages it seeks. Any such payment could have a material adverse effect on our financial condition. For more information, see "Item 3. Legal Proceedings—Anadarko Contingent Consideration Payment Dispute."

We derive a large percentage of our revenues and other income from a small number of coal lessees.

Challenges in the coal mining industry have led to significant consolidation activity. In 2018, Contura Energy and Alpha Natural Resources merged, and our revenues from the two companies on a combined basis accounted for approximately 17% of our total revenues in 2018. In addition, we own significant interests in all four of Foresight Energy's mining operations, which accounted for approximately 22% of our total revenues in 2018. Certain other lessees have made acquisitions over the past few years resulting in their having an increased interest in our coal reserves. Any interruption in these lessees' ability to make royalty payments to us could have a disproportionate material adverse effect on our business and results of operations.

Bankruptcies in the coal industry could have a material adverse effect on our business and results of operations.

Due to the continued challenges in the coal business, a number of coal producers filed for protection under U.S. bankruptcy laws during 2018, including several of our coal lessees. To the extent our leases are accepted or assigned, pre-petition amounts will be cured in full, but we may ultimately make concessions in the financial terms of those leases in order for the reorganized company or new lessor to operate profitably going forward. To the extent our leases are rejected, operations on those leases will cease, and we will be unlikely to recover the full amount of our rejection damages claims. 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.

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 and timing of mining activities;
- processing and blending minerals;

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- 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 are exposed to operating risks that we do not experience in the royalty business through our soda ash joint venture and through our ownership of certain coal transportation assets.

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, including increased maintenance and expansion capital expenditures that we may be required to fund, would result in decreased distributions to NRP. In addition, we are ultimately responsible for operating the transportation infrastructure at Foresight Energy'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.

A significant portion of Ciner Wyoming's historical international sales of soda ash have been to ANSAC, and the termination of the ANSAC membership could adversely affect Ciner Wyoming's ability to compete in certain international markets and Ciner Wyoming's ability to make cash distributions to us.

ANSAC has historically been Ciner Wyoming's largest customer for the years ended December 31, 2018, 2017 and 2016, accounting for 52.0%, 44.7% and 55.2%, respectively, of its net sales. Following termination of the membership in ANSAC, which will be effective December 31, 2021, there is no assurance that Ciner Wyoming will be able to retain existing foreign customers or secure new foreign customers or the related logistics arrangements on favorable terms. Adverse developments in Ciner Wyoming's ability to transport soda ash and sell into the foreign markets currently served by ANSAC could result in lower cash distributions to us from Ciner Wyoming.

We anticipate that Ciner Wyoming will need to increase capital expenditures in order to replace volumes of soda ash currently produced from the deca rehydration process, which could adversely affect Ciner Wyoming's profitability and ability to make distributions to us.

Ciner Wyoming anticipates that its current deca stockpiles will be exhausted by 2023. In order to replace the volumes of soda ash produced from the deca rehydration process following exhaustion of those stockpiles, Ciner Wyoming will need to make significant capital expenditures over the next few years. There is no assurance that any such additional investments will be executed successfully or in a timely manner to enable Ciner Wyoming to maintain soda ash production levels. In addition, if the capital for such investment projects cannot be obtained from alternative financing arrangements, Ciner Wyoming's cash flows may decline, which could limit Ciner Wyoming's ability to make cash distributions to us.

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

Transportation costs represent a significant portion of the total delivered cost for the customers of our lessees. Increases in transportation costs could make coal a less competitive source of energy or could make 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/or other events could temporarily impair the ability of our lessees to supply coal to their customers and/or increase their costs. Many of our lessees are currently experiencing transportation-related issues due in particular to decreased availability and reliability of rail services and port congestion. Our lessees' transportation providers may face difficulties in the future that would 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. For the year ended December 31, 2018, Ciner Wyoming shipped approximately 93.5% of its soda ash from the Green River facility on a single rail line owned and controlled by Union Pacific. Ciner Wyoming's current transportation contract with Union Pacific expires on December 31, 2019. There can be no assurance that this contract will be renewed on terms favorable to Ciner Wyoming or at all. 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, undue reliance should not be placed on our reserve data that is included in this report.

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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.

Our business is subject to cybersecurity risks.

Our business is increasingly dependent on information technologies and services. Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. Although we utilize various procedures and controls to mitigate our exposure to such risks, cybersecurity attacks and other cyber events are evolving, unpredictable, and sometimes difficult to detect, and could lead to unauthorized access to sensitive information or render data or systems unusable.

We do not presently maintain insurance coverage to protect against cybersecurity risks. If we procure such coverage in the future, we cannot ensure that it will be sufficient to cover any particular losses we may experience as a result of such cyber attacks. Any cyber incident could have a material adverse effect on our business, financial condition and results of operations.

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 common units (including common units held by our general partner and its affiliates and including common units deemed to be held by the holders of the preferred units who vote along with the common unitholders on an as-converted basis). Because of their substantial

ownership in us, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates and the holders of the preferred units.
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 (other than the holders of preferred units) 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.

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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 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 common 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 common 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 common unitholder approval (subject to applicable NYSE rules). In addition, we may issue additional common units upon the exercise of the outstanding warrants held by Blackstone and Goldentree. 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.

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

These conflicts may include the following:

- We do not have any employees and we rely solely on employees of affiliates of the general partner;
- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;
- the amount of cash expenditures, borrowings and reserves in any quarter may affect cash available to pay quarterly distributions to unitholders;
- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner’s liability;
- under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arm’s-length negotiations; and
- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

In addition, 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.

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.

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Tax Risks to Our 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 unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our 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 and current Treasury regulations, 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 our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders 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 unitholders, likely causing a substantial reduction in the value of our 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 our unitholders.

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 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, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no current legislative or administrative proposals, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department’s interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a publicly traded partnership in the future.

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 units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our 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, and (iii) repealing the percentage depletion allowance with respect to coal properties. 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 units. We are not aware of any current proposals with regard to these changes.

Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us. Our unitholders' share of our portfolio income may be taxable to them even though they 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, our unitholders are required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax due from them with respect to that income.

For our unitholders subject to the passive loss rules, our current operations include portfolio activities (such as our coal and mineral royalty businesses) and passive activities (such as our soda ash business). 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 royalty businesses, (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, our unitholders' share of our portfolio income may be subject to federal income tax, regardless of other losses they 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 our unitholders, and income tax liabilities arising therefrom may exceed any distributions made with respect to their units.

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, our unitholders 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. Our unitholders may be allocated income and gain from these transactions, and income tax liabilities arising therefrom may exceed any distributions we make to our unitholders. 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. Our 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. Our 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 units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

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 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.

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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 and our current and former unitholders may be required to indemnify us for any taxes (including applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

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 these 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 information statement to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former 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 and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

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

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Distributions in excess of a common unitholder's allocable share of our net taxable income result in a decrease in the tax basis in such unitholder's common units. Accordingly, the amount, if any, of such prior excess distributions with respect to the common units sold will, in effect, become taxable income to our common unitholders if they sell such common units at a price greater than their tax basis in those common units, even if the price they receive is less than their original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if our unitholders sell their common units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

A substantial portion of the amount realized from a unitholder's sale of our units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion and depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Our unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Tax-exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them.
Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our units.
Non-U.S. Unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.
Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale
The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a tax advisor before investing in our 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 our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.
We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The 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.

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A unitholder whose units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those 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 units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those 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 units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

In addition to U.S. federal income taxes, our unitholders 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 our unitholders do not live in any of those jurisdictions. Our unitholders 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, our unitholders 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 the unitholder's responsibility to file all U.S. federal, state and local tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

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

Foresight Energy Disputes

In October 2018, our lawsuits against Foresight Energy and its subsidiaries Hillsboro Energy and Macoupin Energy were settled. The Hillsboro suit was pending in the Circuit Court of the Fourth Judicial Circuit in Montgomery County, Illinois, and the Macoupin suit was pending in Macoupin County, Illinois. We received a payment of $25 million from Foresight Energy in full settlement of the Hillsboro litigation. In addition, we and Hillsboro Energy amended the coal mining lease with respect to the Deer Run mine to change the $30 million recoupable annual minimum payments to $11 million non-recoupable annual minimum payments effective January 1, 2019 and extended the current lease term through the end of 2033. Furthermore, Foresight Energy forfeited its recoupable balances under the Macoupin and Hillsboro leases totaling approximately $37.4 million. All claims were dismissed in both the Hillsboro and Macoupin lawsuits.

Anadarko Contingent Consideration Payment Dispute

In January 2013, we acquired a non-controlling 48.51% general partner interest in OCI Wyoming, L.P. ("OCI LP") and all of the preferred stock and a portion of the common stock of OCI Wyoming Co. ("OCI Co") (which in turn owned a 1% limited partner interest in OCI LP) from Anadarko Holding Company and its subsidiary, Big Island Trona Company (together, "Anadarko"). The remaining general partner interest in OCI LP and common stock of OCI Co were owned by subsidiaries of OCI Chemical Corporation.

The acquisition agreement provided for additional contingent consideration of up to $50 million to be paid by us if certain performance criteria were met at OCI LP as defined in the purchase and sale agreement in any of the years 2013, 2014 or 2015. For those years, we paid an aggregate of $11.5 million to Anadarko in full satisfaction of these contingent consideration payment obligations.

In July 2013, pursuant to a series of transactions in connection with an initial public offering by a subsidiary of OCI Chemical Corporation, the ownership structure in OCI LP was simplified. In connection with such reorganization, we exchanged the stock of OCI Co for a limited partner interest in OCI LP. Following the reorganization, our interest in OCI LP increased to 49%, consisting of both limited and general partner interests. The restructuring did not have any impact on the operations, revenues, management or control of OCI LP.

In July 2017, Anadarko filed a lawsuit against Opco and NRP Trona LLC in the District Court of Harris County, Texas, 157th Judicial District. The complaint alleged that the transactions conducted in 2013 triggered an acceleration of NRP's obligation under the purchase agreement with Anadarko to pay additional contingent consideration in full and demanded immediate payment of such amount, together with interest, court costs and attorneys' fees. We do not believe the reorganization transactions triggered an obligation to pay any additional contingent consideration and we are vigorously defending this lawsuit. However, the ultimate outcome cannot be predicted with certainty and we estimate a possible range of loss between $0, if we prevail, and approximately $40 million, plus interest, court costs and attorneys' fees if Anadarko prevails and is awarded the full damages it seeks.

ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations or other regulatory matters required by SEC regulations for our construction aggregates business sold on December 11, 2018 is included in Exhibit 95.1 to this Annual Report on Form 10-K.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NRP Common Units

Our common units are listed and traded on the NYSE under the symbol "NRP". As of February 5, 2019, there were approximately 15,890 beneficial and registered holders of our common units. The computation of the approximate number of unitholders is based upon a broker survey.

Securities Authorized for Issuance under Equity Compensation Plans

The following table shows the securities authorized for issuance under our 2017 Long-Term Incentive Plan at December 31, 2018. The initial number of common units authorized for issuance pursuant to awards under the plan was 800,000.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	—	—	727,208 (1)
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	—	—	727,208

(1) As of December 31, 2018, 55,329 unvested phantom units were outstanding under the plan. The phantom units convert into common units upon vesting on a one-for-one basis.

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."

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	For the Years Ended December 31,				
(In thousands, except per unit data)	2018 [1] [2]	2017 [2]	2016 [2]	2015 [2]	2014 [2]
Total revenues and other income	$278,512	$246,325	$279,244	$300,635	$308,867
Asset impairments	$18,280	$2,967	$15,861	$378,327	$26,209
Income (loss) from operations	$192,538	$176,559	$181,157	$(170,699)	$176,108
Net income (loss) from continuing operations	$122,360	$82,485	$90,626	$(260,443)	$96,681
Net income from continuing operations excluding impairments	$140,640	$85,452	$106,487	$117,884	$122,890
Net income (loss) from discontinued operations	$17,687	$6,182	$6,266	$(311,277)	$12,149
Net income (loss)	$140,047	$88,667	$96,892	$(571,720)	$108,830
Per common unit amounts (basic)					
Net income (loss) from continuing operations	$7.35	$4.57	$7.28	$(20.80)	$8.37
Net income (loss) from discontinued operations	$1.42	$0.50	$0.50	$(24.94)	$1.05
Net income (loss)	$8.77	$5.06	$7.78	$(45.75)	$9.42
Per common unit amounts (diluted)					
Net income (loss) from continuing operations	$5.90	$3.68	$7.28	$(20.80)	$8.37
Net income (loss) from discontinued operations	$0.86	$0.28	$0.50	$(24.94)	$1.05
Net income (loss)	$6.76	$3.96	$7.78	$(45.75)	$9.42
Distributions paid per common unit	$1.80	$1.80	$1.80	$2.70	$14.00
Average number of common units outstanding - basic	12,244	12,232	12,232	12,232	11,326
Average number of common units outstanding - diluted	20,234	21,950	12,232	12,232	11,326
Net cash provided by (used in)					
Operating activities of continuing operations	$178,282	$112,151	$80,243	$144,907	$189,418
Investing activities of continuing operations	$7,607	$9,807	$65,057	$15,805	$1,566
Financing activities of continuing operations	$(6,839)	$(134,149)	$(146,373)	$(166,443)	$(237,314)
Distributable cash flow [3]	$383,980	$121,958	$255,172	$157,815	$195,045
Free cash flow [3]	$183,440	$121,324	$75,970	$144,210	$193,665
Adjusted EBITDA [3]	$230,241	$211,483	$235,273	$240,553	$260,447
Cash, cash equivalents and restricted cash	$206,030	$26,980	$39,171	$40,244	$45,975
Total assets	$1,341,647	$1,389,164	$1,448,649	$1,674,865	$2,431,549
Current portion of long-term debt, net	$115,184	$79,740	$140,037	$80,745	$80,745
Long-term debt, net	$557,574	$729,608	$990,234	$1,130,696	$1,190,558
Class A Convertible Preferred Units	$164,587	$173,431	$—	$—	$—
Partners' capital	$423,481	$265,211	$151,530	$76,336	$720,155

(1) On January 1, 2018, NRP adopted Accounting Standards Codification (ASC) 606, Revenue from Contracts with Customers, and all the related amendments (the "new revenue standard" and "ASC 606") to all open contracts using the modified retrospective method. NRP recognized a $70.5 million cumulative effect of adoption adjustment in the opening balance of partners' capital on January 1, 2018. Comparative information has not been restated and continues to be reported under the standards in effect for those periods. Refer to "Item 8. Financial Statements and Supplementary Schedules—Note 2. Summary of Significant Accounting Policies" and "Item 8. Financial Statements and Supplementary Schedules—Note 3. Revenue from Contracts with Customers" in this Annual Report on Form 10-K for more information.

(2)

In December 2018, we sold our construction aggregates materials business and have classified the assets and liabilities, operating results and cash flows of the construction aggregates business as discontinued operations for all periods presented. Refer to "Item 8. Financial Statements and Supplementary Schedules—Note 4. Discontinued Operations" in this Annual Report on Form 10-K for more information.

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

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Non-GAAP Financial Measures

Distributable Cash Flow

Distributable cash flow ("DCF") represents net cash provided by (used in) operating activities of continuing operations plus distributions from unconsolidated investment in excess of cumulative earnings, proceeds from sales of assets, including sales of discontinued operations, and return of long-term contract receivables (including 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. In addition, DCF presented below is not calculated or presented on the same basis as Distributable cash flow as defined in our partnership agreement, which is used as a metric to determine whether we are able to increase quarterly distributions to our common unitholders. 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 asses our ability to make cash distributions and repay debt.

Free Cash Flow

Free cash flow ("FCF") represents net cash provided by (used in) operating activities of continuing operations plus distributions from unconsolidated investment in excess of cumulative earnings and return of long-term contract receivables (including affiliate); less maintenance and expansion capital expenditures, cash flow used in acquisition costs classified as financing activities and distributions to non-controlling interest. FCF is calculated before mandatory debt repayments. FCF 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. FCF may not be calculated the same for us as for other companies. FCF 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 our ability to make cash distributions and repay debt.

The following table reconciles net cash provided by operating activities of continuing operations (the most comparable GAAP financial measure) to DCF and FCF for the years ended December 31, 2018, 2017, 2016, 2015, and 2014:

	Year Ended December 31,				
(In thousands)	2018	2017	2016	2015	2014
Net cash provided by operating activities of continuing operations	$178,282	$112,151	$80,243	$144,907	$189,418
Add: distributions from unconsolidated investment in excess of cumulative earnings	2,097	5,646	—	—	3,633
Add: proceeds from sale of assets	2,449	1,151	62,117	13,605	1,380
Add: proceeds from sale of discontinued operations	198,091	—	109,872	—	—
Add: return of long-term contract receivables (including affiliates)	3,061	3,010	2,968	2,463	1,904
Less: maintenance capital expenditures	—	—	(28)	(416)	(316)
Less: distributions to non-controlling interest	—	—	—	(2,744)	(974)
Distributable cash flow	$383,980	$121,958	$255,172	$157,815	$195,045
Less: proceeds from sale of assets	(2,449)	(1,151)	(62,117)	(13,605)	(1,380)
Less: proceeds from sale of discontinued operations	(198,091)	—	(109,872)	—	—
Less: acquisition costs classified as financing activities	—	517	(7,213)	—	—
Free cash flow	$183,440	$121,324	$75,970	$144,210	$193,665

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Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income (loss) from continuing operations less equity earnings from unconsolidated investment, net income attributable to non-controlling interest and gain on reserve swap; plus total distributions from unconsolidated investment, interest expense, net, debt modification expense, loss on extinguishment of debt, depreciation, depletion and amortization and asset impairments. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations. There are significant limitations to using Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring items that materially affect our net income (loss), the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDA reported by different companies. In addition, Adjusted EBITDA presented below is not calculated or presented on the same basis as Consolidated EBITDA as defined in our partnership agreement or Consolidated EBITDDA as defined in Opco's debt agreements. See "Item 8. Financial Statements and Supplementary Data—Note 13. Debt, Net" included elsewhere in this Annual Report on Form 10-K for a description of Opco’s debt agreements. Adjusted EBITDA is a supplemental performance measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis.

The following table reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA for the years ended December 31, 2018, 2017, 2016, 2015, and 2014:

	Year Ended December 31,				
(In thousands)	2018	2017	2016	2015	2014
Net income (loss) from continuing operations	$122,360	$82,485	$90,626	$(260,443)	$96,681
Less: equity earnings from unconsolidated investment	(48,306)	(40,457)	(40,061)	(49,918)	(41,416)
Less: net income attributable to non-controlling interest	(510)	—	—	—	—
Less: gain on reverse swap	—	—	—	(9,290)	(5,690)
Add: total distributions from unconsolidated investment	46,550	49,000	46,550	46,795	46,638
Add: interest expense, net	70,178	82,028	90,531	89,744	79,427
Add: debt modification expense	—	7,939	—	—	—
Add: loss on extinguishment of debt	—	4,107	—	—	—
Add: depreciation, depletion and amortization	21,689	23,414	31,766	45,338	58,598
Add: asset impairments	18,280	2,967	15,861	378,327	26,209
Adjusted EBITDA	$230,241	$211,483	$235,273	$240,553	$260,447

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

Introduction

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

- Executive Overview
- Results of Operations
- Liquidity and Capital Resources
- Off-Balance Sheet Transactions
- Inflation
- Environmental Regulation
- Related Party Transactions
- Summary of Critical Accounting Estimates
- Recent Accounting Standards

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

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Executive Overview

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

Our business is organized into two operating segments:

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

In December 2018, we sold our construction aggregates business for $205 million, before customary purchase price adjustments and transaction expenses, and recorded a gain of $13.1 million. Our exit from the construction aggregates business enabled us to further reduce debt, focus on our Coal Royalty and Other and Soda Ash business segments and represented a strategic shift as we exited the operations of our construction aggregates business. As a result, we have classified the assets and liabilities, operating results and cash flows of the construction aggregates business as discontinued operations in the consolidated financial statements for all periods presented. See "Item 8. Financial Statements and Supplementary Data—Note 4. Discontinued Operations" to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional information. Our debt agreements stipulated that 75% of the asset sale proceeds be used to pay down the Opco Revolving Credit Facility and 25% be offered to the holders of the Opco Senior Notes on a pro-rata basis. The outstanding balance on the Opco Revolving Credit Facility was repaid in December 2018, $49 million was offered to the holders of the Opco Senior Notes in December 2018 and paid in January 2019, and we intend to use the remaining $55 million of net proceeds to repay the Opco Senior Notes as they amortize in 2019.

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

Our 2018 financial results by business segment for the year ended December 31, 2018 are as follows:

(In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
Revenues and other income	$230,206	$48,306	$—	$278,512
Net income (loss) from continuing operations	$160,728	$48,306	$(86,674)	$122,360
Adjusted EBITDA (1)	$200,187	$46,550	$(16,496)	$230,241

Cash flow provided by (used in) continuing operations				
Operating activities	$212,394	$44,453	$(78,565)	$178,282
Investing activities	$5,510	$2,097	$—	$7,607
Financing activities	$—	$—	$(6,839)	$(6,839)
Distributable cash flow [(1)]	$217,904	$46,550	$(78,565)	$383,980
Free cash flow [(1)]	$215,455	$46,550	$(78,565)	$183,440

(1) See "Item 6. Selected Financial Data" for additional information regarding non-GAAP financial measures and reconciliations to the most comparable GAAP financial measures.

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Current Results/Market Commentary

Coal Royalty and Other Business Segment

Results in 2018 were driven by continued strength in both metallurgical and thermal coal markets. Metallurgical coal prices of all grades were driven higher from 2017 levels due to worldwide steel production growth along with a muted supply response from metallurgical coal producers due to various constraints. Benefiting from higher metallurgical coal prices, we derived approximately 65% of our coal royalty revenues and approximately 55% of our coal royalty production from metallurgical coal during the year. Looking ahead into 2019, we expect metallurgical coal prices to remain relatively stable due to supportive steel industry fundamentals combined with logistical and operational supply constraints across the industry. Macro concerns including slowing GDP growth and trade issues could negatively impact the met market.

The domestic market for thermal coal has benefited from increased export demand from Asia, principally India, and northern Europe resulting in higher year over year prices in Central and Northern Appalachia, as well as the Illinois Basin. In addition, the domestic market benefited from higher natural gas prices that increased domestic thermal coal's competitiveness. However, export thermal coal prices and domestic natural gas prices are currently down from the highs of 2018 and thermal coal pricing may be affected accordingly.

Soda Ash Business Segment

Ciner Wyoming's results are primarily affected by the global supply of and demand for soda ash, which in turn directly impacts the prices Ciner Wyoming and other producers charge for its products. Demand for soda ash in the United States is driven in a large part by economic growth and activity levels in the end-markets that the glass-making industry serve, such as the automotive and construction industries. Because the United States is a well-developed market for soda ash, we expect that domestic demand will remain stable for the near future. Because future United States capacity growth is expected to come from the four major producers in the Green River Basin, we also expect that U.S. supply levels will remain relatively stable in the near term.

Soda ash demand in international markets has continued to grow in conjunction with GDP. We expect that future global economic growth will positively influence global demand, which will likely result in increased exports, primarily from the United States, Turkey and to a limited extent, from China, the largest suppliers of soda ash to international markets.

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Results of Operations

Year Ended December 31, 2018 and 2017 Compared

Revenues and Other Income

The following table includes our revenues and other income by operating segment:

	For the Year Ended December 31,			
Operating Segment (In thousands)	2018	2017	Increase (Decrease)	Percentage Change
Coal Royalty and Other	$230,206	$205,868	$ 24,338	12 %
Soda Ash	48,306	40,457	7,849	19 %
Total	$278,512	$246,325	$ 32,187	13 %

The changes in revenues and other income is discussed for each of the operating segments below:

Coal Royalty and Other

The following table presents coal production, coal royalty revenue per ton and coal royalty revenues by major coal producing region, the significant categories of other revenues and other income:

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(In thousands, except per ton data)	For the Year Ended December 31, 2018	2017	Increase (Decrease)	Percentage Change
Coal production (tons)				
Appalachia				
Northern	3,187	2,136	1,051	49 %
Central	14,997	14,735	262	2 %
Southern	1,710	2,256	(546)	(24)%
Total Appalachia	19,894	19,127	767	4 %
Illinois Basin	2,739	4,373	(1,634)	(37)%
Northern Powder River Basin	4,313	4,386	(73)	(2)%
Total coal production	26,946	27,886	(940)	(3)%
Coal royalty revenue per ton				
Appalachia				
Northern	$2.74	$1.53	$1.21	79 %
Central	5.62	5.12	0.50	10 %
Southern	7.20	5.94	1.26	21 %
Illinois Basin	4.63	3.88	0.75	19 %
Northern Powder River Basin	2.65	2.65	—	— %
Combined average coal royalty revenue per ton	4.80	4.33	0.47	11 %
Coal royalty revenues				
Appalachia				
Northern	$8,719	$3,271	$5,448	167 %
Central	84,302	75,489	8,813	12 %
Southern	12,312	13,399	(1,087)	(8)%
Total Appalachia	105,333	92,159	13,174	14 %
Illinois Basin	12,673	16,989	(4,316)	(25)%
Northern Powder River Basin	11,445	11,642	(197)	(2)%
Unadjusted coal royalty revenue	129,451	120,790	8,661	7 %
Coal royalty adjustment for minimum leases[1]	(110)	—	(110)	(100)%
Total coal royalty revenue	$129,341	$120,790	$8,551	7 %
Other revenues				
Production lease minimum revenue[1][2]	$8,207	$30,822	$(22,615)	(73)%
Minimum lease straight-line revenue[1]	2,362	—	2,362	100 %
Property tax revenue	5,422	5,124	298	6 %
Wheelage revenue	6,484	4,734	1,750	37 %
Coal overriding royalty revenue	13,878	9,836	4,042	41 %
Lease modification fees[1]	—	1,000	(1,000)	(100)%
Aggregates royalty revenues	4,739	4,241	498	12 %
Oil and gas royalty revenues	6,608	4,225	2,383	56 %
Other	1,837	1,029	808	79 %
Total other revenues	$49,537	$61,011	$(11,474)	(19)%
Total Coal Royalty and Other revenues	$178,878	$181,801	$(2,923)	(2)%
Transportation and processing services	23,887	20,522	3,365	16 %
Total Coal Royalty and Other segment revenues	$202,765	$202,323	$442	0.2 %
Gain on litigation settlement	25,000	—	25,000	100 %

Gain on asset sales, net	2,441	3,545	(1,104)	(31)%
Total Coal Royalty and Other segment revenues and other income	$230,206	$205,868	$24,338	12 %

(1) These line items were impacted by the adoption of the new revenue recognition standard effective January 1, 2018. The total impact of the adoption of this standard in the year ended December 31, 2018 was a net decrease of $55.6 million in Coal Royalty and Other revenues. For more information on the overall impact of adoption of the new revenue recognition standard and changes to our revenue recognition policies as a result of this adoption, refer to "Item 8. Financial Statements and Supplementary Data—Note 2. Summary of Significant Accounting Policies to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

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(2) Production lease minimum revenue was $30.8 million in 2017 and included any expiration or forfeiture of minimums on all of our leases under ASC 605. Production lease minimum revenue was $8.2 million in 2018, including expired or forfeited minimums and breakage as a result of ASC 606. The $22.6 million decrease is primarily due to minimums expiring in 2018 that were included as breakage in the ASC 606 cumulative effect entry to Partners’ capital on January 1, 2018, rather than to production lease minimum revenue.

Coal Royalty Revenue

Coal royalty revenues increased $8.6 million from 2017 to 2018 primarily driven by the following:

- Appalachia: Coal royalty revenue increased $13.2 million as a result of higher metallurgical and thermal coal prices and higher metallurgical coal production as a result of increased demand primarily in Central and Northern Appalachia, partially offset by lower thermal coal production as a result of capital constraints and declining overall coal demand for certain of our lessees which limit their ability to increase production.
- Illinois Basin: A 37% decrease in production due to the temporary relocation of certain production off of NRP's coal reserves more than offset the 19% increase in coal royalty price per ton on thermal coal and resulted in a $4.3 million decrease in coal royalty revenue. The decrease in coal royalty revenue was partially offset by a $4.2 million increase in overriding royalty revenue and wheelage primarily associated with the production of non-NRP coal.

Other Revenues

Total other revenues decreased $11.5 million from 2017 to 2018 primarily as a result of the impact of the new revenue recognition standard as discussed above. This decrease was partially offset by increased Coal overriding royalty revenue and Wheelage revenue from the production of non-NRP coal as described above in addition to the increased performance of our natural gas royalty properties.

Transportation and Processing Services

Transportation and processing services revenue increased $3.4 million from 2017 to 2018 primarily driven by the increase in tons transported and processed using our assets at the Williamson and Sugar Camp mines and a higher per ton rate at the Macoupin mine.

Gain on Litigation Settlement

Gain on litigation settlement in the year ended December 31, 2018 related to a one-time payment of $25.0 million we received from Foresight Energy to settle the Hillsboro lawsuit.

Gain on Asset Sales, Net

Gain on asset sales, net for the segment decreased $1.1 million from 2017 to 2018. Gains on asset sales during the year ended December 31, 2018 primarily related to the sale of aggregates and other royalty properties and gains on asset sales during the year ended December 31, 2017 included sales of aggregates royalty properties and condemnation payments.

Soda Ash

Revenues and other income related to our Soda Ash segment increased $7.8 million from 2017 to 2018 primarily as a result of Ciner Wyoming's litigation settlement of a royalty dispute that resulted in $12.7 million of income. This increase was partially offset by a $4.9 million decrease in income primarily due to lower production and sales resulting from unexpected equipment repairs needed, which were resolved during the second quarter of 2018, lower production volume in the third quarter of 2018 primarily due to ore grade degradation, a decrease in international sales prices driven by the absence of international sales to Turkey and higher selling, general and administrative expenses related to ANSAC, higher employee compensation expense and higher fees related to Ciner Wyoming's Enterprise Resource Planning project. These decreases were partially offset by lower costs of products sold as a result of a decrease in freight costs driven by no export volumes to Turkey.

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Operating and Other Expenses

The table below presents the significant categories of our consolidated operating and other expenses:

(In thousands)	For the Year Ended December 31, 2018	2017	Increase (Decrease)	Percentage Change
Operating expenses				
Operating and maintenance expenses (including affiliates)	$29,509	$24,883	$4,626	19 %
Depreciation, depletion and amortization (including affiliates)	21,689	23,414	(1,725)	(7)%
General and administrative (including affiliates)	16,496	18,502	(2,006)	(11)%
Asset impairments	18,280	2,967	15,313	516 %
Total operating expenses	$85,974	$69,766	$16,208	23 %
Other expense, net				
Interest expense, net	$70,178	$82,028	$(11,850)	(14)%
Debt modification expense	—	7,939	(7,939)	(100)%
Loss on extinguishment of debt	—	4,107	(4,107)	(100)%
Total other expense, net	$70,178	$94,074	$(23,896)	(25)%

Total operating expenses increased by $16.2 million from 2017 to 2018. The primary reasons for this fluctuation are as follows:

- Operating and maintenance expenses include costs to manage the Coal Royalty and Other segment and primarily consist of taxes, royalty, employee related and legal costs. These costs increased $4.6 million primarily due to increased overriding royalty interest fees, legal costs and property taxes, partially offset by lower bad debt expense.
- Depreciation, depletion and amortization ("DD&A") expense decreased $1.7 million primarily due to a $3.0 million decrease in depletion expense as a result of lower coal production in the Illinois Basin, partially offset by a $1.3 million increase on amortization of intangible assets.
- General and administrative ("G&A") expense decreased $2.0 million primarily due to lower employee-related costs year-over-year.
- Asset impairments increased $15.3 million. Asset impairments in the year ended December 31, 2018 primarily related to a $13.0 million impairment of an aggregates property that we own and lease to our former construction aggregates business, which mines, produces and sells the aggregates, in addition to $5.3 million of impairments related to certain of our coal properties. Asset impairments in the year ended December 31, 2017 primarily consisted of certain coal, aggregates and timber properties.

Total other expense, net decreased $23.9 million from 2017 to 2018. The primary reasons for this fluctuation are as follows:

- Interest expense, net decreased $11.9 million primarily due to lower debt balances in 2018 as a result of repayments of debt.
- Debt modification expense was $7.9 million for the year ended December 31, 2017 and related to costs incurred as a result of the exchange of $241 million of our 2018 Senior Notes for 2022 Senior Notes in March 2017.
- Loss on extinguishment of debt was $4.1 million for the year ended December 31, 2017 and related to the 4.563% premium paid to redeem the 2018 Senior Notes in April 2017.

Income from Discontinued Operations

Income from discontinued operations increased $11.5 million primarily as a result of the $13.1 million gain on sale of our construction aggregates business in the year ended December 31, 2018. This increase was partially offset by decreased net income from the operations of the construction aggregates business as our construction aggregates business' $5.7 million increase in operating expenses more than offset its $3.1 million increase in revenues.

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Adjusted EBITDA (Non-GAAP Financial Measure)

The following table reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA by business segment:

For the Year Ended (In thousands)	Operating Segments: Coal Royalty and Other	Operating Segments: Soda Ash	Corporate and Financing	Total
December 31, 2018				
Net income (loss) from continuing operations	$160,728	$48,306	$(86,674)	$122,360
Less: equity earnings from unconsolidated investment	—	(48,306)	—	(48,306)
Less: net income attributable to non-controlling interest	(510)	—	—	(510)
Add: total distributions from unconsolidated investment	—	46,550	—	46,550
Add: interest expense, net	—	—	70,178	70,178
Add: depreciation, depletion and amortization	21,689	—	—	21,689
Add: asset impairments	18,280	—	—	18,280
Adjusted EBITDA	$200,187	$46,550	$(16,496)	$230,241
December 31, 2017				
Net income (loss) from continuing operations	$154,604	$40,457	$(112,576)	$82,485
Less: equity earnings from unconsolidated investment	—	(40,457)	—	(40,457)
Add: total distributions from unconsolidated investment	—	49,000	—	49,000
Add: interest expense, net	—	—	82,028	82,028
Add: debt modification expense	—	—	7,939	7,939
Add: loss on extinguishment of debt	—	—	4,107	4,107
Add: depreciation, depletion and amortization	23,414	—	—	23,414
Add: asset impairments	2,967	—	—	2,967
Adjusted EBITDA	$180,985	$49,000	$(18,502)	$211,483

Adjusted EBITDA increased $18.8 million from 2017 to 2018. The primary reasons for this fluctuation are as follows:

- Coal Royalty and Other segment Adjusted EBITDA increased $19.2 million primarily as a result of the increase in revenues and other income as discussed above, partially offset by increased operating and maintenance expenses as discussed above.
- Soda Ash segment Adjusted EBITDA decreased $2.5 million as a result of lower cash distributions received from Ciner Wyoming during the year ended December 31, 2018.
- Corporate and financing Adjusted EBITDA increased $2.0 million as a result of the decrease in G&A costs as discussed above.

See "Item 6. Selected Financial Data—Non-GAAP Financial Measures" for an explanation of Adjusted EBITDA.

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Distributable Cash Flow ("DCF") and Free Cash Flow ("FCF") (Non-GAAP Financial Measures)

The following table presents the three major categories of the statement of cash flows by business segment:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2018				
Cash flow provided by (used in) continuing operations				
Operating activities	$212,394	$44,453	$(78,565)	$178,282
Investing activities	5,510	2,097	—	7,607
Financing activities	—	—	(6,839)	(6,839)
December 31, 2017				
Cash flow provided by (used in) continuing operations				
Operating activities	$166,138	$43,354	$(97,341)	$112,151
Investing activities	4,161	5,646	—	9,807
Financing activities	517	—	(134,666)	(134,149)

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The following table reconciles net cash provided by operating activities (the most comparable GAAP financial measure) by business segment to DCF and FCF:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2018				
Net cash provided by (used in) operating activities of continuing operations	$212,394	$44,453	$(78,565)	$178,282
Add: distributions from unconsolidated investment in excess of cumulative earnings	—	2,097	—	2,097
Add: proceeds from sale of assets	2,449	—	—	2,449
Add: proceeds from sale of discontinued operations	—	—	—	198,091
Add: return of long-term contract receivables	3,061	—	—	3,061
Distributable cash flow	$217,904	$46,550	$(78,565)	$383,980
Less: proceeds from sale of assets	(2,449)	—	—	(2,449)
Less: proceeds from sale of discontinued operations	—	—	—	(198,091)
Free cash flow	$215,455	$46,550	$(78,565)	$183,440
December 31, 2017				
Net cash provided by (used in) operating activities of continuing operations	$166,138	$43,354	$(97,341)	$112,151
Add: distributions from unconsolidated investment in excess of cumulative earnings	—	5,646	—	5,646
Add: proceeds from sale of assets	1,151	—	—	1,151
Add: return of long-term contract receivables (including affiliates)	3,010	—	—	3,010
Distributable cash flow	$170,299	$49,000	$(97,341)	$121,958
Less: proceeds from sale of assets	(1,151)	—	—	(1,151)
Less: acquisition costs classified as financing activities	517	—	—	517
Free cash flow	$169,665	$49,000	$(97,341)	$121,324

DCF and FCF increased $262.0 million and $62.1 million, respectively, from 2017 to 2018. The primary reasons for these fluctuations are as follows:

- Coal Royalty and Other segment DCF and FCF increased $47.6 million and $45.8 million, respectively, primarily due to a one-time $25 million payment we received from Foresight Energy to settle the Hillsboro lawsuit in addition to increased cash from coal royalties as a result of higher metallurgical prices and production and increased cash from other revenues.
- Soda Ash segment DCF and FCF decreased $2.5 million as a result of lower cash distributions received from Ciner Wyoming during the year ended December 31, 2018.
- Corporate and Financing DCF and FCF increased $18.8 million primarily as a result of lower performance-based award payments and lower cash paid for interest year-over-year.

Total DCF was also impacted by the $198.1 million proceeds from the sale of our construction aggregates business in the year ended December 31, 2018.

See "Item 6. Selected Financial Data—Non-GAAP Financial Measures" for an explanation of Distributable cash flow and Free cash flow.

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Results of Operations

Year Ended December 31, 2017 and 2016 Compared

Revenues and Other Income

The following table includes our revenues and other income by operating segment:

	For the Year Ended December 31,			
Operating Segment (In thousands)	2017	2016	Increase (Decrease)	Percentage Change
Coal Royalty and Other	$205,868	$239,183	$(33,315)	(14)%
Soda Ash	40,457	40,061	396	1%
Total	$246,325	$279,244	$(32,919)	(12)%

The changes in revenues and other income is discussed for each of the operating segments below:

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Coal Royalty and Other

The table below presents coal production, coal royalty revenue per ton and coal royalty revenues by major coal producing region, the significant categories of other revenues and other income:

(In thousands, except per ton data)	For the Year Ended December 31, 2017	2016	Increase (Decrease)	Percentage Change
Coal production (tons)				
Appalachia				
Northern	2,136	2,312	(176)	(8)%
Central	14,735	13,222	1,513	11 %
Southern	2,256	2,776	(520)	(19)%
Total Appalachia	19,127	18,310	817	4 %
Illinois Basin	4,373	8,116	(3,743)	(46)%
Northern Powder River Basin	4,386	3,781	605	16 %
Gulf Coast	—	0.4	(0.4)	(100)%
Total coal production	27,886	30,207	(2,321)	(8)%
Coal royalty revenue per ton				
Appalachia				
Northern	$1.53	$1.15	$0.38	33 %
Central	5.12	3.64	1.48	41 %
Southern	5.94	3.84	2.10	55 %
Illinois Basin	3.88	3.66	0.22	6 %
Northern Powder River Basin	2.65	2.81	(0.16)	(6)%
Gulf Coast	—	3.28	(3.28)	(100)%
Combined average coal royalty revenue per ton	4.33	3.37	0.96	28 %
Coal royalty revenues				
Appalachia				
Northern	$3,271	$2,667	$604	23 %
Central	75,489	48,119	27,370	57 %
Southern	13,399	10,660	2,739	26 %
Total Appalachia	92,159	61,446	30,713	50 %
Illinois Basin	16,989	29,680	(12,691)	(43)%
Northern Powder River Basin	11,642	10,637	1,005	9 %
Gulf Coast	—	1	(1)	(100)%
Total coal royalty revenue	$120,790	$101,764	$19,026	19 %
Other revenues				
Minimums recognized as revenue	$30,822	$64,591	$(33,769)	(52)%
Property tax revenue	5,124	10,457	(5,333)	(51)%
Wheelage revenue	4,734	2,374	2,360	99 %
Coal overriding royalty revenue	9,836	2,281	7,555	331 %
Lease modification fees	1,000	—	1,000	100 %
Aggregates royalty revenues	4,241	3,163	1,078	34 %

Oil and gas royalty revenues	4,225	3,537	688	19 %
Other	1,029	2,612	(1,583)	(61)%
Total other revenues	$61,011	$89,015	$(28,004)	(31)%
Coal Royalty and Other revenues	$181,801	$190,779	$(8,978)	(5)%
Transportation and processing services	20,522	19,336	1,186	6 %
Total Coal Royalty and Other segment revenues	$202,323	$210,115	$(7,792)	(4)%
Gain on asset sales, net	3,545	29,068	(25,523)	(88)%
Total Coal Royalty and Other segment revenues and other income	$205,868	$239,183	$(33,315)	(14)%

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Coal Royalty Revenue

Coal royalty revenues increased $19.0 million from 2016 to 2017 primarily driven by the following:

- Appalachia: Coal royalty revenue increased $30.7 million as a result of increased metallurgical prices and production.
- Illinois basin: Lower production partially offset by higher royalty revenue per ton led to a $12.7 million decrease in coal royalty revenue. The decreased production was primarily as a result of the temporary relocation of certain production off NRP's coal reserves, which resulted in a $7.5 million increase in coal overriding royalty revenue and wheelage associated with the production of non-NRP coal.

Other Revenues

Total other revenues decreased $28.0 million primarily as a result of a $33.8 million decrease in minimums recognized as revenue due to certain lease modifications and terminations in the second quarter of 2016 and a $5.3 million decrease in property tax reimbursements. The decrease in property tax revenue was fully offset by lower property tax expenses as described in operating and maintenance expenses below. These decreases were partially offset by an increase in coal override revenue and wheelage as discussed above.

Transportation and Processing Services

Transportation and processing services revenue increased $1.2 million from 2016 to 2017 primarily driven by the increase in tons transported and processed using our assets at the Williamson mine.

Gain on Asset Sales, Net

Gain on asset sales, net decreased $25.5 million from 2016 to 2017 primarily as a result of numerous asset sales completed during the year ended December 30, 2016, including an $18.6 million gain on the sale of oil and gas royalty and overriding royalty interests in the Appalachian Basin.

Operating and Other Expenses

The table below presents the significant categories of our consolidated operating and other expenses:

(In thousands)	For the Year Ended December 31, 2017	2016	Increase (Decrease)	Percentage Change
Operating expenses				
Operating and maintenance expenses (including affiliates)	$24,883	$29,890	$(5,007)	(17)%
Depreciation, depletion and amortization (including affiliates)	23,414	31,766	(8,352)	(26)%
General and administrative (including affiliates)	18,502	20,570	(2,068)	(10)%
Asset impairments	2,967	15,861	(12,894)	(81)%
Total operating expenses	$69,766	$98,087	$(28,321)	(29)%
Other expense, net				
Interest expense, net (including affiliates)	$82,028	$90,531	$(8,503)	(9)%
Debt modification expense	7,939	—	7,939	100%
Loss on extinguishment of debt	4,107	—	4,107	100%
Total other expense, net	$94,074	$90,531	$3,543	4%

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Total operating expenses decreased $28.3 million from 2016 to 2017. The primary reasons for these fluctuations are as follows:

- Operating and maintenance expenses decreased $5.0 million primarily due to $5.8 million lower property tax expense as a result of lower property tax rates and property tax values primarily in Kentucky and West Virginia and lower employee related costs.
- DD&A expense decreased $8.4 million driven primarily by lower coal production in the Illinois Basin.
- G&A expense decreased $2.1 million primarily due to decreased legal, consulting and advisory fees incurred in 2016 as a result of the recapitalization transactions completed in March 2017.
- Asset impairments decreased $12.9 million. Asset impairments in the year ended December 31, 2017 primarily consisted of certain coal, aggregates and timber properties and asset impairments in the year ended December 31, 2016 primarily consisted of certain coal and aggregates properties.

Total other expense, net increased $3.5 million from 2016 to 2017. The primary reasons for these fluctuations are as follows:

- Interest expense, net decreased $8.5 million primarily related to lower debt balances during 2017 as a result of the recapitalization transactions entered into in March 2017.
- Debt modification expense was $7.9 million for the year ended December 31, 2017 and related to costs incurred as a result of the exchange of $241 million of our 2018 Senior Notes for 2022 Senior Notes in March 2017.
- Loss on extinguishment of debt was $4.1 million for the year ended December 31, 2017 and related to the 4.563% premium paid to redeem the 2018 Senior Notes in April 2017.

Income from Discontinued Operations

Income from discontinued operations was essentially flat from 2016 to 2017. Income related to our non-operated oil and gas working interest assets decreased $2.2 million as a result of the sale of these assets in July 2016 while income related to our construction aggregates business increased $2.1 million as a result of increased crushed stone, sand and gravel sales volumes year-over-year.

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Adjusted EBITDA (Non-GAAP Financial Measure)

The following table reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA by business segment:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2017				
Net income (loss) from continuing operations	$154,604	$40,457	$(112,576)	$82,485
Less: equity earnings from unconsolidated investment	—	(40,457)	—	(40,457)
Add: total distributions from unconsolidated investment	—	49,000	—	49,000
Add: interest expense, net	—	—	82,028	82,028
Add: debt modification expense	—	—	7,939	7,939
Add: loss on extinguishment of debt	—	—	4,107	4,107
Add: depreciation, depletion and amortization	23,414	—	—	23,414
Add: asset impairments	2,967	—	—	2,967
Adjusted EBITDA	$180,985	$49,000	$(18,502)	$211,483
December 31, 2016				
Net income (loss) from continuing operations	$161,666	$40,061	$(111,101)	$90,626
Less: equity earnings from unconsolidated investment	—	(40,061)	—	(40,061)
Add: total distributions from unconsolidated investment	—	46,550	—	46,550
Add: interest expense, net	—	—	90,531	90,531
Add: depreciation, depletion and amortization	31,766	—	—	31,766
Add: asset impairments	15,861	—	—	15,861
Adjusted EBITDA	$209,293	$46,550	$(20,570)	$235,273

Adjusted EBITDA decreased $23.8 million from 2016 to 2017. The primary reasons for these fluctuations are as follows:

- Coal Royalty and Other segment Adjusted EBITDA decreased $28.3 million. While performance of our coal-related assets improved as described above, the prior year amount included $40.5 million of revenue resulting from one-time lease modifications and $25.5 million higher gains on asset sales, net.
- Soda Ash segment Adjusted EBITDA increased $2.5 million as a result of increased cash distributions received in the year ended December 31, 2017.
- Corporate and financing Adjusted EBITDA increased $2.1 million primarily due to legal and consulting fees related to the recapitalization activities incurred in 2016.

See "Item 6. Selected Financial Data—Non-GAAP Financial Measures" for an explanation of Adjusted EBITDA.

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Distributable Cash Flow ("DCF") and Free Cash Flow ("FCF") (Non-GAAP Financial Measures)

The following table presents the three major categories of the statement of cash flows by business segment:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2017				
Cash flow provided by (used in) continuing operations				
Operating activities	$166,138	$43,354	$(97,341)	$112,151
Investing activities	4,161	5,646	—	9,807
Financing activities	517	—	(134,666)	(134,149)
December 31, 2016				
Cash flow provided by (used in) continuing operations				
Operating activities	$134,490	$46,550	$(100,797)	$80,243
Investing activities	65,057	—	—	65,057
Financing activities	16	(7,229)	(139,160)	(146,373)

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The following table reconciles net cash provided by operating activities (the most comparable GAAP financial measure) by business segment to DCF and FCF:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2017				
Net cash provided by (used in) operating activities of continuing operations	$166,138	$43,354	$(97,341)	$112,151
Add: distributions from unconsolidated investment in excess of cumulative earnings	—	5,646	—	5,646
Add: proceeds from sale of assets	1,151	—	—	1,151
Add: return of long-term contract receivables (including affiliates)	3,010	—	—	3,010
Distributable cash flow	$170,299	$49,000	$(97,341)	$121,958
Less: proceeds from sale of assets	(1,151)	—	—	(1,151)
Less: acquisition costs classified as financing activities	517	—	—	517
Free cash flow	$169,665	$49,000	$(97,341)	$121,324
December 31, 2016				
Net cash provided by (used in) operating activities of continuing operations	$134,490	$46,550	$(100,797)	$80,243
Add: proceeds from sale of assets	62,117	—	—	62,117
Add: proceeds from sale of discontinued operations	—	—	—	109,872
Add: return of long-term contract receivables—affiliate	2,968	—	—	2,968
Less: maintenance capital expenditures	(28)	—	—	(28)
Distributable cash flow	$199,547	$46,550	$(100,797)	$255,172
Less: proceeds from sale of assets	(62,117)	—	—	(62,117)
Less: proceeds from sale of discontinued operations	—	—	—	(109,872)
Less: acquisition costs classified as financing activities	16	(7,229)	—	(7,213)
Free cash flow	$137,446	$39,321	$(100,797)	$75,970

DCF decreased $133.2 million from 2016 to 2017. This decrease is due primarily to the $109.9 million proceeds from the sale of our non-operated oil and gas working interest assets in 2016 in addition to the following:

- Coal Royalty and Other segment DCF decreased $29.2 million primarily due to $61.0 million higher proceeds from asset sales in 2016 as compared to 2017, partially offset by a $31.6 increase in cash provided by operating activities as a result of improved performance of segment assets in 2017.
- Corporate and Financing DCF increased $3.5 million primarily as a result of lower cash paid for interest and lower legal, consulting and advisory fees following the completion of the recapitalization transactions in March 2017.
- Soda Ash DCF increased $2.5 million as a result of higher cash distributions received from Ciner Wyoming in 2017.

FCF increased $45.4 million primarily as a result of the $31.6 million increase in cash provided by operating activities from the Coal Royalty and Other segment. FCF also increased as a result of the $7.2 million cash paid for acquisition costs in our Soda Ash segment in 2016, in addition to higher cash distributions received from Ciner Wyoming in 2017 and the $3.5 million increase in operating cash flows related to lower cash paid for interest and lower legal, consulting and advisory fees following the completion of the recapitalization transactions in March 2017.

See "Item 6. Selected Financial Data—Non-GAAP Financial Measures" for an explanation of Distributable cash flow and Free cash flow.

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Liquidity and Capital Resources

Current Liquidity

As of December 31, 2018, we had total liquidity of $306.0 million, consisting of $101.8 million of cash and cash equivalents, $104.2 million of restricted cash and $100.0 million in borrowing capacity under our Opco Credit Facility. The $104.2 million of restricted cash represents the remaining net proceeds from the sale of our construction aggregates business that is required to be used to repay debt, make acquisitions or make capital expenditures per the terms of our debt agreements. In January 2019, we used approximately $49 million of this restricted cash to repay principal amounts on the Opco Senior Notes, and we intend to use the remaining $55 million to repay the Opco Senior Notes as they amortize in 2019. We remain focused on further reducing our debt and improving our liquidity metrics.

Cash Flows

Cash flows provided by operating activities increased $61.8 million, from $127.1 million in the year ended December 31, 2017 to $188.9 million in the year ended December 31, 2018 primarily related to increased operating cash flows in our Coal Royalty and Other segment as a result of a one-time $25 million payment we received from Foresight Energy to settle the Hillsboro lawsuit in addition to increased cash from coal royalties as a result of higher metallurgical prices and production and increased cash from other revenues. Also contributing to the increase in cash provided by operating activities was the decrease in G&A payments primarily as a result of the payment of the performance-based awards in 2017 following the completion of our recapitalization transactions in addition to lower cash paid for interest on our debt.

Cash flow provided by operating activities increased $19.2 million, from $108.0 million in the year ended December 31, 2016 to $127.1 million in the year ended December 31, 2017. Cash flows from continuing operations increased $31.9 million primarily from increased operational performance from our Coal Royalty and Other segment assets year-over-year. This increase was partially offset by a $12.7 million decrease in operating cash flow from discontinued operations primarily due to cash flows from our non-operated oil and gas working interest assets prior to their sale in 2016.

Cash flow provided by investing activities increased $187.1 million, from $3.5 million in the year ended December 31, 2017 to $190.6 million in the year ended December 31, 2018. Cash flows from discontinued operations increased $189.3 million as a result of the $198.1 million proceeds received from the sale of our construction aggregates business in December 2018, partially offset by increased construction aggregates capital expenditures during 2018. Cash flows from continuing operations decreased $2.2 million primarily due to a lower portion of our distribution from Ciner Wyoming classified as an investing activity in 2018.

Cash flow provided by investing activities decreased $163.3 million, from $166.8 million in the year ended December 31, 2016 to $3.5 million in the year ended December 31, 2017. Investing cash flows from discontinued operations decreased $108.0 million primarily as a result of the $109.9 million proceeds received from the sale of our non-operated oil and gas working interest assets in the year ended December 31, 2016. Investing cash flows from continuing operations decreased $55.3 million primarily as a result of the proceeds received in 2016 from the sales of our oil and gas royalty and overriding royalty and aggregates royalty properties.

Cash flows used in financing activities increased $62.1 million, from $141.2 million in the year ended December 31, 2017 to $203.3 million in the year ended December 31, 2018 primarily due to the proceeds received in 2017 related to recapitalization transactions, partially offset by the first quarter 2017 debt repayments and debt issuance costs paid as a result of the March 2017 recapitalization transactions. Cash flow used in financing activities also increased as a result of the $21.4 million increase in preferred unit distributions and the $8.8 million redemption of the PIK units in

the year ended December 31, 2018.
Cash flow used in financing activities decreased $145.0 million from $286.2 million in the year ended December 31, 2016 to $141.2 million in the year ended December 31, 2017. This decrease in cash flow used is primarily due to the proceeds received from the issuance of Preferred Units and warrants and 2022 Senior Notes in 2017. These proceeds were partially offset by additional debt repayments and debt issuance costs paid in the first quarter of 2017 as a result of the March 2017 recapitalization transactions.

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Capital Resources and Obligations

Debt

We had the following debt outstanding as of December 31, 2018 and 2017:

	December 31,	
(In thousands)	2018	2017
Current portion of long-term debt, net	$115,184	$79,740
Long-term debt, net	557,574	729,608
Total debt, net	$672,758	$809,348

We have been and continue to be in compliance with the terms of the financial covenants contained in our debt agreements. For additional information regarding our debt and the agreements governing our debt, including the covenants contained therein, see "Item 8. Financial Statements and Supplementary Data—Note 13. Debt, Net" in this Annual Report on Form 10-K.

Long-Term Contractual Obligations

The following table reflects our long-term, non-cancelable contractual obligations as of December 31, 2018:

	Payments Due by Period						
Contractual Obligations (In thousands)	Total	2019	2020 (4)	2021	2022	2023	Thereafter
NRP:							
Long-term debt principal payments (including current maturities) (1)	$345,638	$—	$—	$—	$345,638	$—	$ —
Long-term debt interest payments (1)	127,022	36,292	36,292	36,292	18,146	—	—
Opco:							
Long-term debt principal payments (including current maturities) (2)	341,500	116,125	46,436	39,634	39,634	39,634	60,037
Long-term debt interest payments (3)	54,476	16,018	12,013	9,421	7,172	4,923	4,929
Total	$868,636	$168,435	$94,741	$85,347	$410,590	$44,557	$ 64,966

(1) The amounts indicated in the table include principal and interest due on NRP’s 2022 Notes.
(2) The amounts indicated in the table include principal due on Opco’s senior notes.
(3) The amounts indicated in the table include interest due on Opco’s senior notes.
(4) Not included in the table above is the Opco Credit Facility, which matures on April 30, 2020. At December 31, 2018 we did not have any borrowings outstanding under the Opco Credit Facility and have $100.0 million in available borrowing capacity.

Off-Balance Sheet Transactions

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

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on operations for the years ended December 31, 2018, 2017 and 2016.

Environmental Regulation

For additional information on environmental regulation that may have a material impact on our business, see "Items 1. and 2. Business and Properties—Regulation and Environmental Matters."

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Related Party Transactions

The information required by this Item is included under "Item 8. Financial Statements and Supplementary Data—Note 15. Related Party Transactions" and "Item 13. Certain Relationships and Related Transactions, and Director Independence" in this Annual Report on Form 10-K and is incorporated by reference herein.

Summary of Critical Accounting Policies

Preparation of the accompanying financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See "Item 8. Financial Statements and Supplementary Data—Note 2. Summary of Significant Accounting Policies" in the audited consolidated financial statements of this Form 10-K for discussion of our significant accounting policies. The following critical accounting policies are affected by estimates and assumptions used in the preparation of consolidated financial statements. We evaluate our estimates and assumptions on a regular basis. Actual results could differ from those estimates.

Revenues

Coal Royalty and Other segment revenues
Royalty-based leases. In accordance with previous accounting standards in effect prior to January 1, 2018, we recognized all coal and aggregates royalty revenue over the lease term based on production. The recognition of revenue from minimum payments was deferred until either recoupment through royalty production occurred or when the recoupment period expired for unrecouped minimums. Under the new revenue recognition standard, we have defined our coal and aggregates royalty lease performance obligation as providing the lessee the right to mine and sell our coal or aggregates over the lease term. We then evaluated the likelihood that consideration we expected to receive from our lessees resulting from production would exceed consideration expected to be received from minimum payments over the lease term.
As a result of this evaluation, revenue recognition from our royalty-based leases is based on either production or minimum payments as follows:

- Production Leases: Leases for which we expect that consideration from production will be greater than consideration from minimums over the lease term. Revenue recognition for these leases is recognized over time based on production as Coal royalty revenue or Aggregates royalty revenue, as applicable. Deferred revenue from minimums is recognized as royalty revenue when recoupment occurs or as Production lease minimum revenue when the recoupment period expires. In addition, we recognize breakage revenue from minimums when we determine that recoupment is remote. This breakage revenue is included in Production lease minimum revenue.
- Minimum Leases: Leases for which we expect that consideration from minimums will be greater than consideration from production over the lease term. Revenue recognition for these leases is recognized straight-line over the lease term based on the minimum consideration amount as Minimum lease straight-line revenue.

This evaluation is performed at the inception of the lease and only reassessed upon modification or renewal of the lease.
Oil and gas related revenues consist of revenues from royalties and overriding royalties and are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. Also, included within oil and gas royalties are lease bonus payments, which are generally paid upon the execution of a lease. We also have overriding royalty revenue interests in coal reserves. Revenue from these interests is recognized over time based on when the coal is sold.

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Wheelage. Revenue related to fees collected per ton to transport foreign coal across property we own that is recognized over time as transportation across our property occurs.

Other revenue. Other revenue consists primarily of rental payments and surface damage fees related to certain land we own and is recognized straight-line over time as it is earned. Other revenues also include property tax revenues. The majority of property taxes paid on our properties are reimbursable by the lessee and are recognized on a gross basis over time which reflects the reimbursement of property taxes by the lessee. Property taxes we pay are included in Operating and maintenance expenses on our Consolidated Statements of Comprehensive Income.

Transportation and processing services revenue. We own transportation and processing infrastructure that is leased to third parties for throughput fees. Revenue is recognized over time based on the coal tons transported over the beltlines or processed through the facilities.

Contract modifications

Contract modifications that impact goods or services or the transaction price are evaluated in accordance with ASC 606. A majority of our contract modifications pertain to our coal and aggregates royalty contracts and include, but are not limited to, extending the lease term, changes to royalty rates, floor prices or minimum consideration, assignment of the contract, forfeiture of recoupment rights or termination due to the exhaustion of merchantable and mineable reserves. Consideration received in conjunction with a modification of an ongoing lease will be deferred and recognized straight-line over the remaining term of the contract. Consideration received to assign a lease to another party and related forfeited minimums will be recognized immediately upon the termination of the contract. Fees from contract modifications are recognized in Lease modification fees within Coal royalty and other revenues on our Consolidated Statements of Comprehensive Income while modifications in royalty rates and minimums will be recognized prospectively in accordance with the above lease classification.

In accordance with the transition guidance in paragraph 606-10-65-1, revenues from contracts that were modified before January 1, 2018 were not retrospectively restated for those modifications and instead reflected the aggregate effect of those modifications when identifying the satisfied and unsatisfied performance obligations, determining the transaction price and allocating the transaction price to the satisfied and unsatisfied performance obligation.

Contract Assets and Liabilities from Contracts with Customers

Contract assets include receivables from contracts with customers and are recorded when the right to consideration becomes unconditional. Receivables are recognized when the minimums are contractually owed, production occurs or minimums are accrued for based on the passage of time.

Contract liabilities represent minimum consideration received, contractually owed or earned based on the passage of time. The current portion of deferred revenue relates to deferred revenue on minimum leases and lease modification fees that are to be recognized as revenue on a straight-line basis over the next twelve months. The long-term portion of deferred revenue relates to deferred revenue on production leases and lease modification fees that are to be recognized as revenue on a straight-line basis beyond the next twelve months. Due to uncertainty in the amount of deferred revenue that will be recouped and recognized as Coal royalty revenue from production leases over the next twelve months, we are unable to estimate the current portion of deferred revenue.

Equity in Earnings of Ciner Wyoming.

We account for non-marketable equity investments using the equity method of accounting if the investment gives it the ability to exercise significant influence over, but not control of, an investee. Our 49% investment in Ciner Wyoming is accounted for using this method.

Under the equity method of accounting, investments are stated at initial cost and are adjusted for subsequent additional investments and the proportionate share of earnings or losses and distributions. The basis difference between the investment and the proportional share of investee's net assets is attributed to net tangible assets and is amortized over its estimated useful life. The carrying value in Ciner Wyoming is recognized in Equity in unconsolidated investment in our Consolidated Balance Sheets. Our adjusted share of the earnings or losses of Ciner Wyoming and amortization of the basis difference is recognized in Equity in earnings of Ciner Wyoming in the Consolidated Statements of Comprehensive Income. We increase our investment for our proportional share of distributions received from Ciner Wyoming. These cash flows are reported utilizing the cumulative earnings approach. Under this approach, distributions received are considered returns on investment and classified as operating cash inflows unless the cumulative distributions received exceed our cumulative equity in earnings. The excess of cumulative distributions received over our cumulative equity in earnings are considered returns of investment and classified as investing cash inflows.

Mineral Rights

Mineral rights owned and leased are recorded at its original cost of construction or, upon acquisition, at fair value of the assets acquired. Coal and aggregates mineral rights are depleted on a unit-of-production basis by lease, based upon minerals mined in relation to the net cost of the mineral properties and estimated proven and probable tonnage as defined by the SEC's Industry Guide 7 and estimated by our internal reserve engineers. The technologies and economic data used by our internal reserve engineers in the estimation of our proved reserves include, but are not limited to, drill logs, geophysical logs, geologic maps including isopach, mine, and coal quality, cross sections, statistical analysis, and available public production data. There are numerous uncertainties inherent in estimating the quantities and qualities of recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results.

Asset Impairment

We have developed procedures to evaluate our long-lived assets for possible impairment periodically or whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. Potential events or circumstances include, but are not limited to, specific events such as a reduction in economically recoverable reserves or production ceasing on a property for an extended period. A long-lived asset is deemed impaired when the future expected undiscounted cash flows from its use and disposition is less than the assets' carrying value. Impairment is measured based on the estimated fair value, which is usually determined based upon the present value of the projected future cash flow compared to the assets' carrying value. We believe our estimates of cash flows and discount rates are consistent with those of principal market participants.

We evaluate our equity investment for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment loss. The fair value of the impaired investment is based on quoted market prices, or upon the present value of expected cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

Recent Accounting Standards

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, which includes adverse changes in commodity prices and interest rates as discussed below:

Commodity Price Risk

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing commodity prices. Historically, coal prices have been volatile, with prices fluctuating widely, and they

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are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results. In particular, substantially lower prices would significantly reduce revenue and could potentially trigger an impairment of our coal properties or a violation of certain financial debt covenants. Because substantially all of our reserves are coal, changes in coal prices have a more significant impact on our financial results.

We are dependent upon the effective marketing of the coal mined by our lessees. Our lessees sell the coal under various long-term and short-term contracts as well as on the spot market. Current conditions in the coal industry may make it difficult for our lessees to extend existing contracts or enter into supply contracts with terms of one year or more. Our lessees' failure to negotiate long-term contracts could adversely affect the stability and profitability of our lessees' operations and adversely affect our future financial results. If more coal is sold on the spot market, coal royalty revenues may become more volatile due to fluctuations in spot coal prices.
The market price of soda ash directly affects the profitability of Ciner Wyoming's operations. If the market price for soda ash declines, Ciner Wyoming's sales will decrease. Historically, the global market and, to a lesser extent, the domestic market for soda ash have been volatile, and those markets are likely to remain volatile in the future.

Interest Rate Risk

Our exposure to changes in interest rates results from our borrowings under the Opco Credit Facility, which is subject to variable interest rates based upon LIBOR. At December 31, 2018 we did not have any borrowings outstanding under the Opco Credit Facility.

Fair Value of Financial Assets and Liabilities

Our financial assets and liabilities consist of cash and cash equivalents, restricted cash, contracts receivable, debt, Preferred Units and Warrants. The carrying amounts reported on the Consolidated Balance Sheets for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature.

We use available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount we would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk.
The following table shows the carrying amount and estimated fair value of our debt and contracts receivable:

	December 31, 2018		December 31, 2017	
(In thousands)	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Debt:				
NRP 2022 Senior Notes [(1)]	$334,024	$356,871	$330,404	$366,376
Opco Senior Notes [(2)]	338,734	352,599	418,944	447,538
Opco Revolving Credit Facility [(3)]	—	—	60,000	60,000
Assets:				
Contracts receivable, current and long-term [(4)]	$40,776	$34,704	$43,826	$30,517

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

(2)

Due to no observable quoted prices on these instruments, the Level 3 fair value is estimated by management using quotations obtained for the NRP Senior Notes on the closing trading prices near period end.

(3) The Level 3 fair value approximates the outstanding borrowing amount because the interest rates are variable and reflective of market rates and the terms of the credit facility allow the Partnership to repay this debt at any time without penalty.

(4) The Level 3 fair value is determined based on the present value of future cash flow projections related to the underlying assets.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Partners of Natural Resource Partners L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Natural Resource Partners L.P. (the Partnership) as of December 31, 2018 and 2017, the related consolidated statements of comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, based on our audits and the report of other auditors, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We did not audit the financial statements of Ciner Wyoming LLC (Ciner Wyoming), a limited liability company in which the Partnership has a 49% interest. In the consolidated financial statements, the Partnership's investment in Ciner Wyoming is stated at $247 million and $245 million as of December 31, 2018 and 2017, respectively, and the Partnership's equity in the net income of Ciner Wyoming is stated at $48 million in 2018, $40 million in 2017 and $40 million in 2016. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Ciner Wyoming, is based solely on the report of the other auditors.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 7, 2019 expressed an unqualified opinion thereon.

Adoption of ASU No. 2014-09

As discussed in Note 2 to the consolidated financial statements, the Partnership adopted ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)" effective January 1, 2018. As a result, for the year ended December 31, 2018, the Partnership changed its method for revenue recognition related to royalty lease arrangements.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2002.

Houston, Texas
March 7, 2019

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Ciner Wyoming LLC (“the Company”) as of December 31, 2018 and 2017, and the related statements of operations and comprehensive income, members’ equity, and cash flows for each of the three years in the period ended December 31, 2018 and the related notes included in Exhibit 99.1 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Atlanta, Georgia
March 7, 2019

We have served as the Company's auditor since 2008.

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS

	December 31,	
(In thousands, except unit data)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$101,839	$26,980
Restricted cash	104,191	—
Accounts receivable, net	32,024	24,050
Accounts receivable—affiliates	34	161
Prepaid expenses and other	3,462	3,782
Current assets of discontinued operations	993	36,423
Total current assets	$242,543	$91,396
Land	24,008	24,008
Plant and equipment, net	984	1,348
Mineral rights, net	743,112	778,419
Intangible assets, net	42,513	46,820
Equity in unconsolidated investment	247,051	245,433
Long-term contracts receivable	38,945	40,776
Long-term assets of discontinued operations	—	155,942
Other assets	2,491	4,866
Other assets—affiliate	—	156
Total assets	$1,341,647	$1,389,164
LIABILITIES AND CAPITAL		
Current liabilities		
Accounts payable	$548	$1,010
Accounts payable—affiliates	1,866	490
Accrued liabilities	12,347	11,542
Accrued liabilities—affiliates	—	515
Accrued interest	14,345	15,484
Current portion of deferred revenue	3,509	—
Current portion of long-term debt, net	115,184	79,740
Current liabilities of discontinued operations	947	11,768
Total current liabilities	$148,746	$120,549
Deferred revenue	49,044	100,605
Long-term debt, net	557,574	729,608
Long-term liabilities of discontinued operations	—	2,220
Other non-current liabilities	1,150	588
Other non-current liabilities—affiliate	—	346
Total liabilities	$756,514	$953,916
Commitments and contingencies (see Note 17)		
Class A Convertible Preferred Units (250,000 and 258,844 units issued and outstanding at December 31, 2018 and 2017, respectively, at $1,000 par value per unit; liquidation preference of $1,500 per unit)	$164,587	$173,431
Partners' capital		
Common unitholders' interest (12,249,469 and 12,232,006 units issued and outstanding at December 31, 2018 and 2017, respectively)	355,113	199,851
General partner's interest	5,014	1,857

Warrant holders' interest	66,816	66,816
Accumulated other comprehensive loss	(3,462)	(3,313)
Total partners' capital	$423,481	$265,211
Non-controlling interest	(2,935)	(3,394)
Total capital	$420,546	$261,817
Total liabilities and capital	$1,341,647	$1,389,164

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

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(In thousands, except per unit data)	2018	2017	2016
Revenues and other income			
Coal royalty and other	$178,394	$158,399	$144,520
Coal royalty and other—affiliates	484	23,402	46,259
Transportation and processing services	23,887	14,510	—
Transportation and processing services—affiliate	—	6,012	19,336
Equity in earnings of Ciner Wyoming	48,306	40,457	40,061
Gain on litigation settlement	25,000	—	—
Gain on asset sales, net	2,441	3,545	29,068
Total revenues and other income	$278,512	$246,325	$279,244
Operating expenses			
Operating and maintenance expenses	$17,894	$16,771	$20,737
Operating and maintenance expenses—affiliates	11,615	8,112	9,153
Depreciation, depletion and amortization	21,689	22,406	28,581
Amortization expense—affiliate	—	1,008	3,185
General and administrative	12,838	13,513	16,979
General and administrative—affiliates	3,658	4,989	3,591
Asset impairments	18,280	2,967	15,861
Total operating expenses	$85,974	$69,766	$98,087
Income from operations	$192,538	$176,559	$181,157
Other expense, net			
Interest expense, net	$(70,178)	$(82,028)	$(90,008)
Interest expense—affiliate	—	—	(523)
Debt modification expense	—	(7,939)	—
Loss on extinguishment of debt	—	(4,107)	—
Total other expense, net	$(70,178)	$(94,074)	$(90,531)
Net income from continuing operations	$122,360	$82,485	$90,626
Income from discontinued operations (see Note 4)	17,687	6,182	6,266
Net income	$140,047	$88,667	$96,892
Less: net income attributable to non-controlling interest	(510)	—	—
Net income attributable to NRP	$139,537	$88,667	$96,892
Less: income attributable to preferred unitholders	(30,000)	(25,453)	—
Net income attributable to common unitholders and general partner	$109,537	$63,214	$96,892
Net income attributable to common unitholders	$107,346	$61,950	$95,229
Net income attributable to the general partner	2,191	1,264	1,663
Income from continuing operations per common unit (see Note 7)			
Basic	$7.35	$4.57	$7.28
Diluted	5.90	3.68	7.28

Net income per common unit (see Note 7)			
Basic	$8.77	$5.06	$7.78
Diluted	6.76	3.96	7.78
Net income	$140,047	$88,667	$96,892
Comprehensive income (loss) from unconsolidated investment and other	(149)	(1,647)	486
Comprehensive income	$139,898	$87,020	$97,378
Less: comprehensive income attributable to non-controlling interest	(510)	—	—
Comprehensive income attributable to NRP	$139,388	$87,020	$97,378

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

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

(In thousands)	Common Unitholders Units	Common Unitholders Amounts	General Partner	Warrant Holders	Accumulated Other Comprehensive Income (Loss)	Partners' Capital Excluding Non-Controlling Interest	Non-Controlling Interest	Total Capital
Balance at December 31, 2015	12,232	$79,094	$(606)	$—	$ (2,152)	$ 76,336	$ (3,394)	$72,942
Net income	—	95,229	1,663	—	—	96,892	—	96,892
Distributions to common unitholders and general partner	—	(22,014)	(451)	—	—	(22,465)	—	(22,465)
Non-cash contributions	—	—	281	—	—	281	—	281
Comprehensive income from unconsolidated investment and other	—	—	—	—	486	486	—	486
Balance at December 31, 2016	12,232	$152,309	$887	$—	$ (1,666)	$ 151,530	$ (3,394)	$148,136
Net income (1)	—	86,894	1,773	—	—	88,667	—	88,667
Distributions to common unitholders and general partner	—	(22,018)	(449)	—	—	(22,467)	—	(22,467)
Distributions to preferred unitholders	—	(17,334)	(354)	—	—	(17,688)	—	(17,688)
Issuance of Warrants	—	—		66,816	—	66,816	—	66,816
Comprehensive loss from unconsolidated investment and other	—	—	—	—	(1,647)	(1,647)	—	(1,647)
Balance at December 31, 2017	12,232	$199,851	$1,857	$66,816	$ (3,313)	$ 265,211	$ (3,394)	$261,817
Cumulative effect of adoption of accounting standard (See Note 3)	—	69,057	1,409	—	—	70,466	—	70,466
Net income (2)	—	136,746	2,791	—	—	139,537	510	140,047
Distributions to common unitholders and general partner	—	(22,036)	(450)	—	—	(22,486)	—	(22,486)
Distributions to preferred unitholders	—	(29,660)	(605)	—	—	(30,265)	—	(30,265)
Issuance of unit-based awards	17	546	—	—	—	546	—	546
Unit-based awards amortization and vesting	—	560	—	—	—	560	—	560
Comprehensive income (loss) from unconsolidated	—	49	12	—	(149)	(88)	(51)	(139)

investment and other								
Balance at December 31, 2018	12,249	$355,113	$5,014	$66,816	$ (3,462)	$ 423,481	$ (2,935)	$420,546

(1) Net income for the year ended December 31, 2017 includes $25.5 million attributable to Preferred Unitholders that accumulated during the period, of which $24.9 million is allocated to the common unitholders and $0.5 million is allocated to the general partner.

(2) Net income for the year ended December 31, 2018 includes $30.0 million attributable to Preferred Unitholders that accumulated during the period, of which $29.4 million is allocated to the common unitholders and $0.6 million is allocated to the general partner.

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

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
(In thousands)	2018	2017	2016
Cash flows from operating activities			
Net income	$140,047	$88,667	$96,892
Adjustments to reconcile net income to net cash provided by operating activities of continuing operations:			
Depreciation, depletion and amortization	21,689	22,406	28,581
Amortization expense—affiliate	—	1,008	3,185
Distributions from unconsolidated investment	44,453	43,354	46,550
Equity earnings from unconsolidated investment	(48,306)	(40,457)	(40,061)
Gain on asset sales, net	(2,441)	(3,545)	(29,068)
Debt modification expense	—	7,939	—
Loss on extinguishment of debt	—	4,107	—
Income from discontinued operations	(17,687)	(6,182)	(6,266)
Asset impairments	18,280	2,967	15,861
Unit-based compensation expense	1,434	18	1,217
Amortization of debt issuance costs and other	7,334	9,077	8,638
Other—affiliates	(201)	1,207	993
Change in operating assets and liabilities:			
Accounts receivable	(6,251)	5,905	1,545
Accounts receivable—affiliates	127	367	(313)
Accounts payable	(238)	(185)	517
Accounts payable—affiliates	1,376	1	—
Accrued liabilities	134	(8,478)	3,628
Accrued liabilities—affiliates	(115)	515	—
Accrued interest	(1,138)	(105)	(779)
Accrued interest—affiliates	—	—	(456)
Deferred revenue	19,465	(5,791)	(35,881)
Deferred revenue—affiliates	—	(10,166)	(12,063)
Other items, net	320	(478)	(2,477)
Net cash provided by operating activities of continuing operations	$178,282	$112,151	$80,243
Net cash provided by operating activities of discontinued operations	10,641	14,988	27,718
Net cash provided by operating activities	$188,923	$127,139	$107,961
Cash flows from investing activities			
Distributions from unconsolidated investment in excess of cumulative earnings	$2,097	$5,646	$—
Proceeds from sale of assets	2,449	1,151	62,117
Return of long-term contract receivable	3,061	2,206	—
Return of long-term contract receivable—affiliate	—	804	2,968
Acquisition of plant and equipment and other	—	—	(28)
Net cash provided by investing activities of continuing operations	$7,607	$9,807	$65,057
Net cash provided by (used in) investing activities of discontinued operations	183,021	(6,264)	101,758
Net cash provided by investing activities	$190,628	$3,543	$166,815

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
(In thousands)	2018	2017	2016
Cash flows from financing activities			
Proceeds from issuance of preferred units and warrants, net	$—	$242,100	$—
Proceeds from issuance of 2022 Senior Notes, net	—	103,688	—
Borrowings on credit facility	35,000	77,000	20,000
Repayments of loans	(175,706)	(492,319)	(183,141)
Redemption of preferred units paid-in-kind	(8,844)	—	—
Distributions to common unitholders and general partner	(22,486)	(22,467)	(22,465)
Distributions to preferred unitholders	(30,265)	(8,844)	—
Contributions from discontinued operations	195,690	5,784	52,642
Debt issuance costs and other	(228)	(39,091)	(13,409)
Net cash used in financing activities of continuing operations	$(6,839)	$(134,149)	$(146,373)
Net cash used in financing activities of discontinued operations	(196,509)	(7,077)	(139,805)
Net cash used in financing activities	$(203,348)	$(141,226)	$(286,178)
Net increase (decrease) in cash, cash equivalents and restricted cash	$176,203	$(10,544)	$(11,402)
Cash, cash equivalents and restricted cash of continuing operations at beginning of period	$26,980	$39,171	$40,244
Cash, cash equivalents and restricted cash of discontinued operations at beginning of period	2,847	1,200	11,529
Cash, cash equivalents and restricted cash at beginning of period	$29,827	$40,371	$51,773
Cash, cash equivalents and restricted cash at end of period	$206,030	$29,827	$40,371
Less: cash, cash equivalents and restricted cash of discontinued operations at end of period	—	2,847	1,200
Cash, cash equivalents and restricted cash of continuing operations at end of period	$206,030	$26,980	$39,171
Supplemental cash flow information:			
Cash paid during the period for interest from continuing operations	$64,991	$72,850	$84,380
Non-cash investing and financing activities:			
Issuance of 2022 Senior Notes in exchange for 2018 Senior Notes	$—	$240,638	$—

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

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

1. Organization and Nature of Operations

Natural Resource Partners L.P. (the "Partnership"), a Delaware limited partnership, was formed in April 2002. The general partner of the Partnership is NRP (GP) LP ("NRP GP"), a Delaware limited partnership, whose general partner is GP Natural Resource Partners LLC, a Delaware limited liability company. The Partnership engages principally in the business of owning, managing and leasing a diversified portfolio of mineral properties in the United States, including interests in coal, trona, soda ash and other natural resources and is organized into two operating segments further described in Note 8. Segment Information. As used in these Notes to Consolidated Financial Statements, the terms "NRP," "we," "us" and "our" refer to Natural Resource Partners L.P. and its subsidiaries, unless otherwise stated or indicated by context.

The Partnership’s operations are conducted through, and its operating assets are owned by, its subsidiaries. The Partnership owns its subsidiaries through one wholly owned operating company, NRP (Operating) LLC ("Opco"). NRP GP has sole responsibility for conducting the Partnership's business and for managing its operations. Because NRP GP is a limited partnership, its general partner, GP Natural Resource Partners LLC, conducts its business and operations, and the board of directors and officers of GP Natural Resource Partners LLC makes decisions on its behalf. Robertson Coal Management LLC ("RCM"), 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 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"), RCM is entitled to appoint the directors of the Board of Directors of GP Natural Resource Partners LLC. RCM has delegated the right to appoint one director to Blackstone.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying Consolidated Financial Statements of the Partnership have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP"). The consolidated financial statements include the accounts of Natural Resource Partners L.P. and its wholly owned subsidiaries, as well as BRP LLC ("BRP"), a joint venture with International Paper Company controlled by the Partnership. The Partnership has an equity investment in Ciner Wyoming through which it is able to exercise significant influence over but does not control the investee and is not the primary beneficiary of the investee’s activities and is accounted for using the equity method. Intercompany transactions and balances have been eliminated. Certain reclassifications have been made to prior year amounts on the Consolidated Statements of Comprehensive Income and Consolidated Statements of Cash Flows to conform with current year presentation. These reclassifications have no impact on previously reported net income or total cash flows from operating, investing or financing activities.

Recasting of Certain Prior Period Information

As described in Note 4. Discontinued Operations, the Partnership has classified the assets and liabilities, operating results and cash flows of its construction aggregates business as discontinued operations in its consolidated financial statements for all periods presented.

Use of Estimates

Preparation of the accompanying financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in the accompanying Consolidated Balance Sheets, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses in the accompanying Consolidated Statements of Comprehensive Income during the reporting period. Actual results could differ from those estimates. The most significant estimates pertain to coal and aggregates reserves and related cash flow estimates which are used to compute depreciation, depletion and amortization and impairments of coal and aggregates properties and commitments and contingencies.

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Fair Value

The Partnership discloses certain assets and liabilities using fair value as defined by authoritative guidance. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. See Note 14. Fair Value Measurements for further details.

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

- Level 1—Quoted prices in active markets for identical assets or liabilities.
- Level 2—Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.
- Level 3—Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. Level 3 assets and liabilities include financial assets and liabilities whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation.

Cash, Cash Equivalents and Restricted Cash

The Partnership considers all highly liquid short-term investments with an original maturity of three months or less to be cash equivalents. Restricted cash at December 31, 2018 included cash proceeds received from the sale of the Partnership's construction aggregates business required to be used to repay debt, make acquisitions or make capital expenditures per the terms of its and Opco's debt agreements, as defined in Note 13. Debt, Net. NRP intends to use these proceeds to repay debt.

Allowance for Doubtful Accounts

The Partnership records an allowance for doubtful accounts for its accounts receivables and notes receivables which it determines to be uncollectible based on the specific identification method. Receivables are written off when collection efforts are exhausted and future recovery is doubtful. The allowance for doubtful accounts receivable is included in Accounts receivable, net and the allowance for doubtful accounts for notes receivable is included in Other current assets on the Partnership's Consolidated Balance Sheets, respectively. The allowance for doubtful accounts related to accounts receivable was $4.8 million at December 31, 2017. The allowance for doubtful accounts related to notes receivable included in Other current assets was $1.2 million at both December 31, 2018 and 2017, respectively. The Partnership recorded bad debt expense of $0.1 million, $2.4 million and $0.3 million, respectively, included in Operating and maintenance expense (including affiliates) on its Consolidated Statements of Comprehensive Income for the years ended December 31, 2018, 2017 and 2016, respectively.

Plant and Equipment

Plant and equipment is recorded at its original cost of construction or, upon acquisition, at fair value of the asset acquired and consists of coal preparation plants, related coal handling facilities, and other coal and aggregates transportation and processing infrastructure. Expenditures for new facilities or that substantially increase the useful life of property are capitalized and reported in the Consolidated Statements of Cash Flows as an investing activity. These assets are depreciated on a straight-line basis over their useful lives generally as follows:

	Years
Buildings and improvements	20 to 40
Machinery and equipment	5 to 12
Leasehold improvements	Life of Lease

Mineral Rights

Mineral rights owned and leased are recorded at its original cost of construction or, upon acquisition, at fair value of the assets acquired. Coal and aggregates mineral rights are depleted on a unit-of-production basis by lease, based upon minerals mined in relation to the net cost of the mineral properties and estimated proven and probable tonnage therein.

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

Intangible Assets

The Partnership’s intangible assets consist primarily of contracts that at acquisition were more favorable for the Partnership than prevailing market rates, known as above-market contracts. Management expects for the above-market rates to be received until the reserves are exhausted on its above-market contracts, which includes additional renewal terms of the respective leases. The estimated fair values of the above-market rate contracts are determined based on the present value of future cash flow projections related to the underlying assets acquired. Intangible assets are amortized on a unit-of-production basis.

Asset Impairment

The Partnership has developed procedures to evaluate its long-lived assets for possible impairment periodically or whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. Potential events or circumstances include, but are not limited to, specific events such as a reduction in economically recoverable reserves or production ceasing on a property for an extended period. This analysis is based on historic, current and future performance and considers both quantitative and qualitative information. A long-lived asset is deemed impaired when the future expected undiscounted cash flows from its use and disposition is less than the assets’ carrying value. Impairment is measured based on the estimated fair value, which is usually determined based upon the present value of the projected future cash flow compared to the assets’ carrying value. The Partnership believes its estimates of cash flows and discount rates are consistent with those of principal market participants.

The Partnership evaluates its equity investment for impairment when events or changes in circumstances indicate, in management’s judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether potential impairment has occurred. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment loss. The fair value of the impaired investment is based on quoted market prices (Level 1), or upon the present value of expected cash flows using discount rates believed to be consistent with those used by principal market participants (Level 3), plus market analysis of comparable assets owned by the investee, if appropriate.

Revenue Recognition

Coal Royalty and Other Segment Revenues

Royalty-based leases. Approximately two-thirds of the Partnership's royalty-based leases have initial terms of five to 40 years, with substantially all lessees having the option to extend the lease for additional terms. For these types of leases, the lessees generally make payments to NRP based on the greater of a percentage of the gross sales price or a fixed price per ton of mineral they mine or sell. Most of NRP’s coal and aggregates royalty leases require the lessee to pay quarterly or annual minimum amounts, either made in advance or arrears, which are generally recoupable through actual royalty production over certain time periods that generally range from three to five years.
In accordance with previous accounting standards in effect prior to January 1, 2018, NRP recognized all coal and aggregates royalty revenue over the lease term based on production. The recognition of revenue from minimum payments was deferred until either recoupment through royalty production occurred or when the recoupment period

expired for unrecouped minimums.

Under the new revenue recognition standard, management has defined NRP's coal and aggregates royalty lease performance obligation as providing the lessee the right to mine and sell NRP's coal or aggregates over the lease term. The Partnership then evaluated the likelihood that consideration NRP expected to receive from its lessees resulting from production would exceed consideration expected to be received from minimum payments over the lease term.

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As a result of this evaluation, revenue recognition from the Partnership's royalty-based leases is based on either production or minimum payments as follows:

- Production Leases: Leases for which the Partnership expects that consideration from production will be greater than consideration from minimums over the lease term. Revenue recognition for these leases is recognized over time based on production as Coal royalty revenue or Aggregates royalty revenue, as applicable. Deferred revenue from minimums is recognized as royalty revenue when recoupment occurs or as Production lease minimum revenue when the recoupment period expires. In addition, NRP recognizes breakage revenue from minimums when NRP determines that recoupment is remote. This breakage revenue is included in Production lease minimum revenue.
- Minimum Leases: Leases for which the Partnership expects that consideration from minimums will be greater than consideration from production over the lease term. Revenue recognition for these leases is recognized straight-line over the lease term based on the minimum consideration amount as Minimum lease straight-line revenue.

This evaluation is performed at the inception of the lease and only reassessed upon modification or renewal of the lease.

Oil and gas related revenues consist of revenues from royalties and overriding royalties and are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. Also, included within oil and gas royalties are lease bonus payments, which are generally paid upon the execution of a lease. The Partnership also has overriding royalty revenue interests in coal reserves. Revenue from these interests is recognized over time based on when the coal is sold.

Wheelage. Revenue related to fees collected per ton to transport foreign coal across property owned by the Partnership that is recognized over time as transportation across the property occurs.

Other revenue. Other revenue consists primarily of rental payments and surface damage fees related to certain land owned by the Partnership and is recognized straight-line over time as it is earned. Other revenues also include property tax revenues. The majority of property taxes paid on the Partnership's properties are reimbursable by the lessee and are recognized on a gross basis over time which reflects the reimbursement of property taxes by the lessee. Property taxes paid by NRP are included in Operating and maintenance expenses on the Partnership's Consolidated Statements of Comprehensive Income.

Transportation and processing services revenue. The Partnership owns transportation and processing infrastructure that is leased to third parties for throughput fees. Revenue is recognized over time based on the coal tons transported over the beltlines or processed through the facilities.

Contract modifications

Contract modifications that impact goods or services or the transaction price are evaluated in accordance with ASC 606. A majority of the Partnership's contract modifications pertain to its coal and aggregates royalty contracts and include, but are not limited to, extending the lease term, changes to royalty rates, floor prices or minimum consideration, assignment of the contract, forfeiture of recoupment rights or termination due to the exhaustion of merchantable and mineable reserves. Consideration received in conjunction with a modification of an ongoing lease will be deferred and recognized straight-line over the remaining term of the contract. Consideration received to assign a lease to another party and related forfeited minimums will be recognized immediately upon the termination of the contract. Fees from contract modifications are recognized in Lease modification fees within Coal royalty and other revenues on our Consolidated Statements of Comprehensive Income while modifications in royalty rates and minimums will be recognized prospectively in accordance with the above lease classification.

In accordance with the transition guidance in paragraph 606-10-65-1, revenues from contracts that were modified before January 1, 2018 were not retrospectively restated for those modifications and instead reflected the aggregate effect of those modifications when identifying the satisfied and unsatisfied performance obligations, determining the transaction price and allocating the transaction price to the satisfied and unsatisfied performance obligation.

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Contract Assets and Liabilities from Contracts with Customers

Contract assets include receivables from contracts with customers and are recorded when the right to consideration becomes unconditional. Receivables are recognized when the minimums are contractually owed, production occurs or minimums accrued for based on the passage of time.

Contract liabilities represent minimum consideration received, contractually owed or earned based on the passage of time. The current portion of deferred revenue relates to deferred revenue on minimum leases and lease modification fees that are to be recognized as revenue on a straight-line basis over the next twelve months. The long-term portion of deferred revenue relates to deferred revenue on production leases and lease modification fees that are to be recognized as revenue on a straight-line basis beyond the next twelve months. Due to uncertainty in the amount of deferred revenue that will be recouped and recognized as Coal royalty revenue from its production leases over the next twelve months, the Partnership is unable to estimate the current portion of deferred revenue.

See "—Recently Adopted Accounting Standards—Revenue Recognition" below for information regarding the impact of adopting the new revenue recognition standard in January 2018.

Equity in Earnings from Ciner Wyoming

The Partnership accounts for non-marketable equity investments using the equity method of accounting if the investment gives it the ability to exercise significant influence over, but not control of, an investee. The Partnership's 49% investment in Ciner Wyoming is accounted for using this method. Under the equity method of accounting, investments are stated at initial cost and are adjusted for subsequent additional investments and the proportionate share of earnings or losses and distributions. The basis difference between the investment and the proportional share of investee's net assets is attributed to net tangible assets and is amortized over its estimated useful life. The carrying value in Ciner Wyoming is recognized in Equity in unconsolidated investment in the Partnership's Consolidated Balance Sheets. The Partnership's adjusted share of the earnings or losses of Ciner Wyoming and amortization of the basis difference is recognized in Equity in earnings of Ciner Wyoming in the Consolidated Statements of Comprehensive Income. The Partnership increases its investment for its proportional share of distributions received from Ciner Wyoming. These cash flows are reported utilizing the cumulative earnings approach. Under this approach, distributions received are considered returns on investment and classified as operating cash inflows unless the cumulative distributions received exceed the Partnership's cumulative equity in earnings. The excess of cumulative distributions received over the Partnership's cumulative equity in earnings are considered returns of investment and classified as investing cash inflows.

Property Taxes

The Partnership is responsible for paying property taxes on the properties it owns. Typically, the lessees are contractually responsible for reimbursing the Partnership for property taxes on the leased properties. The payment of and reimbursement of property taxes is included in Operating and maintenance expenses and in Coal royalty and other revenues, respectively, in the Consolidated Statements of Comprehensive Income.

Transportation Revenue and Expense

The Partnership records transportation revenue and pays transportation costs to a Foresight Energy LP ("Foresight Energy") affiliate to operate equipment on behalf of the Partnership. The revenue and expenses related to these transactions are recorded as Transportation and processing services (or Transportation and processing services—affiliates) and Operating and maintenance expenses or (Operating and maintenance expenses—affiliates), respectively, in the Consolidated Statements of Comprehensive Income. Subsequent to May 9, 2017, Foresight Energy is no longer deemed a related party. Refer to Note 15. Related Party Transactions for further details.

Unit-Based Compensation

The Partnership has awarded unit-based compensation in the form of equity-based awards and phantom units. Compensation cost is measured at the grant date for equity-classified awards and remeasured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is generally the vesting period. Forfeitures are recognized as they occur. Unit-based compensation expense for all awards is recognized in General and administrative expense and Operating and maintenance expense in the Consolidated Statements of Comprehensive Income.

Deferred Financing Costs

Deferred financing costs consist of legal and other costs related to the issuance of the Partnership's debt. These costs are amortized over the term of the respective line-of-credit or debt arrangements. Deferred financing costs related to the Partnership's revolving credit facility are included in Other assets (long-term) on the Partnership's Consolidated Balance Sheets. Deferred financing costs related to the Partnership's note agreements are included as a direct deduction from the carrying amount of the debt liability in Current portion of long-term debt, net or Long-term debt, net on the Partnership's Consolidated Balance Sheets.

Income Taxes

The Partnership is not subject to federal or material state income taxes, as the unitholders are taxed individually on their allocable share of taxable income. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities. In the event of an examination of the Partnership's tax return, the tax liability of the unitholders could be changed if an adjustment in the Partnership's income is ultimately sustained by the taxing authorities.

Recently Adopted Accounting Standards

Revenue Recognition
On January 1, 2018, NRP adopted Accounting Standards Codification (ASC) 606, Revenue from Contracts with Customers, and all the related amendments (the "new revenue standard" and "ASC 606") to all open contracts using the modified retrospective method. The adoption of the new revenue standard impacted royalty revenue from NRP's coal and aggregates royalty leases as further described below. NRP recognized a $70.5 million cumulative effect of adoption adjustment in the opening balance of partners' capital on January 1, 2018. Prior year information has not been restated and continues to be reported under the accounting standards in effect for those periods. The new revenue standard had no impact on revenues from NRP's Soda Ash operating segment or on the discontinued operations.
A majority of NRP's coal and aggregates royalty revenue continues to be recognized over the lease term based on production. For coal and aggregates royalty leases for which NRP expects consideration from minimum payments to be greater than consideration from production over the lease term, royalty revenue is now recognized straight-line over the lease term based on the minimum payment consideration. The cumulative effects of the changes made to the Partnership's Consolidated Balance Sheet at January 1, 2018 for the adoption of the new revenue standard were as follows:

(In thousands)	Balance at December 31, 2017	Adjustments due to ASC 606	Balance at January 1, 2018
Assets			
Accounts receivable, net (including affiliates)	$24,211	$ 4,875	$29,086
Liabilities			
Current portion of deferred revenue	$—	$ 1,022	$1,022
Deferred revenue	100,605	(66,613)	33,992
Partners' capital			

Common unitholders' interest	$199,851	$ 69,057	$268,908
General partner's interest	1,857	1,409	3,266
Total partners' capital	265,211	70,466	335,677

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The impact of adoption of the new revenue standard on NRP’s Consolidated Balance Sheet and Consolidated Statement of Comprehensive Income was as follows:

	As of December 31, 2018		
(In thousands)	As Reported	Balances without Adoption of ASC 606	Effect of Change
Assets			
Accounts receivable, net (including affiliates)	$32,058	$27,520	$4,538
Total assets	1,341,647	1,337,109	4,538
Liabilities and capital			
Current portion of deferred revenue	$3,509	$—	$3,509
Deferred revenue	49,044	62,783	(13,739)
Total liabilities	756,514	766,744	(10,230)
Partners’ capital			
Common unitholders’ interest	$355,113	$340,640	$14,473
General partner’s interest	5,014	4,719	295
Total partners’ capital	423,481	408,713	14,768
Total liabilities and capital	1,341,647	1,337,109	4,538

	For the Year Ended December 31, 2018		
(In thousands, except per unit data)	As Reported	Amounts without Adoption of ASC 606	Effect of Change
Coal royalty and other revenues (including affiliates) [(1)]	$178,878	$234,428	$(55,550)
Net income from continuing operations	122,360	178,058	(55,698)
Net income	140,047	195,745	(55,698)
Net income per common unit (basic)	8.77	13.23	(4.46)
Net income per common unit (diluted)	6.76	9.46	(2.70)

(1) The total effect of adopting ASC 606 was $55.6 million during the year ended December 31, 2018, which included $33.4 million related to the forfeiture of recoupable balances in connection with the fourth quarter 2018 settlement of the Macoupin and Hillsboro lawsuits, the majority of which was previously recognized in partners' capital upon adoption and $7.2 million of modification fees and forfeited recoupable balances related to fourth quarter 2018 lease modifications which were deferred under ASC 606 and will be recognized straight-line over the respective modified lease terms.

Recently Issued Accounting Standards

Leases

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). The new standard requires a lessee to recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. This standard does not apply to leases that explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. The guidance also requires disclosures designed to give financial statement users information on the amount, timing and uncertainty of cash flows arising from leases. The guidance is effective for annual and interim periods beginning after December 15, 2018 and is to be adopted using a modified retrospective approach. The Partnership will adopt this standard effective January 1, 2019 and does not expect that the provisions of this guidance will have a material impact on its consolidated financial statements.

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

3. Revenue from Contracts with Customers

Coal Royalty and Other Segment

The following table represents the Partnership's Coal Royalty and Other segment revenues (including affiliates) by major source:

(In thousands)	Year Ended December 31, 2018
Coal royalty revenue	$ 129,341
Production lease minimum revenue	8,207
Minimum lease straight-line revenue	2,362
Property tax revenue	5,422
Wheelage revenue	6,484
Coal overriding royalty revenue	13,878
Aggregates royalty revenue	4,739
Oil and gas royalty revenue	6,608
Other revenue	1,837
Coal royalty and other revenues [(1)]	$ 178,878
Transportation and processing services revenue [(2)]	23,887
Total Coal royalty and other segment revenues	$ 202,765

(1) Represents revenue from contracts with customers as defined under ASC 606.

(2) Revenue from contracts with customers as defined under ASC 606 was $13.2 million for the year ended December 31, 2018. The remaining transportation and processing services revenue of $10.7 million for the year ended December 31, 2018 was related to other NRP-owned infrastructure leased to and operated by third party operators accounted for under ASC 840, Leases. See Note 15. Related Party Transactions for more information on the transportation and processing services.

Contract Assets and Liabilities

The following table details the Partnership's Coal Royalty and Other segment receivables and liabilities resulting from contracts with customers:

(In thousands)	December 31, 2018	January 1, 2018
Receivables		
Total accounts receivable, net (including affiliates)[(1)]	$ 29,001	$ 25,443
Prepaid expenses and other [(2)]	2,483	2,830
Contract liabilities		
Current portion of deferred revenue	$ 3,509	$ 1,022
Deferred revenue	49,044	33,992

(1) Included in this amount is $4.4 million and $1.9 million of accounts receivable related to accrued minimum consideration as of December 31, 2018 and January 1, 2018, respectively.

(2) Notes receivable from contracts with customers are included within Prepaid expenses and other in the Consolidated Balance Sheets.

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NATURAL RESOURCE PARTNERS L.P.
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The following table shows the activity related to the Partnership's Coal Royalty and Other segment deferred revenue:

(In thousands)	Year Ended December 31, 2018
Balance at December 31, 2017	$100,605
Cumulative adjustment for change in accounting principle [1]	(65,591)
Balance at January 1, 2018 (current and non-current)	$35,014
Recognition of previously deferred revenue	(20,242)
Accrued minimum payments and lease modification fees due	5,592
Cash received for minimum payments and lease modification fees	32,189
Balance at December 31, 2018 (current and non-current) [2]	$52,553

(1) Included in this amount is $(67.5) million recognized in Partners' capital and $1.9 million of accrued minimum consideration recognized in Accounts receivable, net.

(2) Included in this amount is $7.2 million of deferred modification fees and forfeited recoupable balances which will be recognized straight-line over the respective modified lease terms in Coal Royalty and other revenues on the Consolidated Statements of Comprehensive Income over the remaining terms of the modified leases, which extend over the next 6 years.

The following table shows the Partnership's Coal Royalty and Other segment revenue recognized during the year ended December 31, 2018 that was included in the deferred revenue balance at the beginning of the period:

(In thousands)	Year Ended December 31, 2018
Production leases - revenue impact	
Recoupments recognized in Coal and aggregates royalty revenue	$ 10,178
Breakage revenue recognized in Production lease minimum revenue	7,169
Expiration of unrecouped minimums recognized in Production lease minimum revenue	935
Minimum leases - revenue impact	
Minimum lease amortization recognized in Minimum lease straight-line revenue	1,960
Total previously deferred revenue recognized	$ 20,242

Remaining Performance Obligations

The Partnership's non-cancelable annual minimum payments due under the lease terms of its coal and aggregates royalty leases are as follows:

Lease Term [1]	Weighted Average Remaining Years as of December 31, 2018	Annual Minimum Payments (In thousands)
1 - 5 years	0.6	$ 13,072
5 - 10 years	1.3	13,060
10+ years	9.0	41,202

(1) The Partnership applied the practical expedient for disclosing remaining performance obligations for contracts with an expected duration of one year or less, and have excluded those contracts from this disclosure.

The Partnership's non-cancelable annual minimum payments on its coal and aggregates royalty leases are recognized as revenue as discussed above. In addition, the Partnership's non-cancelable annual minimum payments due under terms of its coal and aggregates overriding royalty agreements include a $1.8 million annual minimum that expires in 2023 and a $1.0 million minimum that expires upon exhaustion of the mineable and recoverable coal reserves, respectively.

4. Discontinued Operations

In December 2018, the Partnership sold VantaCore Partners LLC, its construction aggregates materials business for $205 million, before customary purchase price adjustments and transaction expenses, and recorded a gain of $13.1 million. The Partnership's debt agreements require that 75% of the asset sale proceeds be used to pay down the Opco Revolving Credit Facility (as defined in Note 13. Debt, Net) and 25% be offered to the holders of its Opco Senior Notes (as defined in Note 13. Debt, Net) on a pro-rata basis. The outstanding balance was repaid on the Opco Revolving Credit Facility in December 2018, $49 million was offered to the holders of the Opco Senior Notes in December 2018 and paid in January 2019 and the remaining $55 million of net cash proceeds was restricted as of December 31, 2018. NRP intends to use these remaining proceeds to repay its Opco Senior Notes as they amortize in 2019.

In July 2016, NRP Oil and Gas LLC ("NRP Oil and Gas") sold its non-operated oil and gas working interest assets for $116.1 million in gross sales proceeds. The sale had an effective date of April 1, 2016.

The Partnership's exit from both its construction aggregates materials business and non-operated oil and gas working interest business represented strategic shifts to reduce debt and focus on its Coal Royalty and Other and Soda Ash business segments. As a result, the Partnership classified the assets and liabilities, operating results and cash flows of these businesses as discontinued operations in its Consolidated Balance Sheets, Consolidated Statements of Comprehensive Income and Consolidated Statements of Cash Flows for all periods presented.

The following tables present the carrying amounts of the Partnership's assets and liabilities of discontinued operations in the Consolidated Balance Sheets:

	December 31, 2018		
(In thousands)	Construction Aggregates	NRP Oil and Gas	Total
ASSETS			
Current assets:			
Accounts receivable, net	$5	$988	$993
Total assets of discontinued operations	$5	$988	$993
LIABILITIES			
Current liabilities:			
Accounts payable (including affiliates)	$181	$—	$181
Accrued liabilities	766	—	766
Total liabilities of discontinued operations	$947	$—	$947

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	December 31, 2017		
(In thousands)	Construction Aggregates	NRP Oil and Gas	Total
ASSETS			
Current assets:			
Cash and cash equivalents	$2,847	$—	$2,847
Accounts receivable, net	22,976	991	23,967
Inventory	7,553	—	7,553
Prepaid expenses and other	2,056	—	2,056
Total current assets of discontinued operations	35,432	991	36,423
Land	1,239	—	1,239
Plant and equipment, net	44,822	—	44,822
Mineral rights, net	105,466	—	105,466
Intangible assets, net	2,734	—	2,734
Other assets	1,681	—	1,681
Total assets of discontinued operations	$191,374	$991	$192,365
LIABILITIES			
Current liabilities:			
Accounts payable (including affiliates)(1)	$6,019	$—	$6,019
Accrued liabilities	5,348	—	5,348
Other	—	401	401
Total current liabilities of discontinued operations	11,367	401	11,768
Other non-current liabilities	2,220	—	2,220
Total liabilities of discontinued operations	$13,587	$401	$13,988

(1) See Note 15. Related Party Transactions for additional information on the Partnership's related party liabilities.

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

The following tables present summarized financial results of the Partnership's discontinued operations in the Consolidated Statements of Comprehensive Income:

	For the Year Ended December 31, 2018		
(In thousands)	Construction Aggregates	NRP Oil and Gas	Total
Revenues and other income:			
Construction aggregates	$116,066	$—	$116,066
Road construction and asphalt paving services	18,400	—	18,400
Oil and gas	—	(3)	(3)
Gain on asset sales, net	13,414	—	13,414
Total revenues and other income	$147,880	$(3)	$147,877
Operating expenses:			
Operating and maintenance expenses (including affiliates)(1)	$117,568	$134	$117,702
Depreciation, depletion and amortization	12,218	—	12,218
Asset impairments	232	—	232
Total operating expenses	$130,018	$134	$130,152
Interest expense, net	(38)	—	(38)
Income (loss) from discontinued operations	$17,824	$(137)	$17,687

(1) See Note 15. Related Party Transactions for additional information on the Partnership's related party expenses.

	For the Year Ended December 31, 2017		
(In thousands)	Construction Aggregates	NRP Oil and Gas	Total
Revenues and other income:			
Construction aggregates	$112,970	$—	$112,970
Road construction and asphalt paving services	18,411	—	18,411
Oil and gas	—	38	38
Gain (loss) on asset sales	311	(289)	22
Total revenues and other income	$131,692	$(251)	$131,441
Operating expenses:			
Operating and maintenance expenses (including affiliates)(1)	$111,633	$290	$111,923
Depreciation, depletion and amortization	12,579	—	12,579
Asset impairments	64	—	64
Total operating expenses	$124,276	$290	$124,566

Interest expense, net	(693)	—	(693)
Income (loss) from discontinued operations	$6,723	$(541)	$6,182

(1) See Note 15. Related Party Transactions for additional information on the Partnership's related party expenses.

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

(In thousands)	For the Year Ended December 31, 2016 Construction Aggregates	NRP Oil and Gas	Total
Revenues and other income:			
Construction aggregates	$103,755	$—	$103,755
Road construction and asphalt paving services	17,047	—	17,047
Oil and gas	—	16,486	16,486
Gain on asset sales, net	13	8,274	8,287
Total revenues and other income	$120,815	$24,760	$145,575
Operating expenses:			
Operating and maintenance expenses (including affiliates)(1)	$100,656	$11,503	$112,159
Depreciation, depletion and amortization	14,506	7,527	22,033
Asset impairments	1,065	564	1,629
Total operating expenses	$116,227	$19,594	$135,821
Interest expense, net	—	(3,488)	(3,488)
Income from discontinued operations	$4,588	$1,678	$6,266

(1) See Note 15. Related Party Transactions for additional information on the Partnership's related party expenses.

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

(In thousands)	Year Ended December 31, 2018	2017	2016
Cash paid for interest	$—	$—	$1,906
Plant, equipment and mineral rights funded with accounts payable or accrued liabilities	881	294	—

Capital expenditures related to the Partnership's discontinued operations were $10.9 million, $7.6 million and $6.7 million during the years ended December 31, 2018, 2017 and 2016, respectively.

5. Class A Convertible Preferred Units and Warrants

On March 2, 2017, NRP issued $250 million of Class A Convertible Preferred Units representing limited partner interests in NRP (the "Preferred Units") to certain entities controlled by funds affiliated with The Blackstone Group, L.P. (collectively referred to as "Blackstone") and certain affiliates of GoldenTree Asset Management LP (collectively referred to as "GoldenTree") (together the "Preferred Purchasers") pursuant to a Preferred Unit and Warrant Purchase Agreement. NRP issued 250,000 Preferred Units to the Preferred Purchasers at a price of $1,000 per Preferred Unit (the "Per Unit Purchase Price"), less a 2.5% structuring and origination fee. The Preferred Units entitle the Preferred Purchasers to receive cumulative distributions at a rate of 12% per year, up to one half of which NRP may pay in additional Preferred Units (such additional Preferred Units, the "PIK Units"). The Preferred Units have a perpetual term, unless converted or redeemed as described below.

NRP also issued two tranches of warrants (the "Warrants") to purchase common units to the Preferred Purchasers (Warrants to purchase 1.75 million common units with a strike price of $22.81 and Warrants to purchase 2.25 million common units with a strike price of $34.00). The Warrants may be exercised by the holders thereof at any time before the eighth anniversary of the closing date. Upon exercise of the Warrants, NRP may, at its option, elect to settle the Warrants in common units or cash, each on a net basis.

After March 2, 2022 and prior to March 2, 2025, the holders of the Preferred Units may elect to convert up to 33% of the outstanding Preferred Units in any 12-month period into common units if the volume weighted average trading price of our common units (the "VWAP") for the 30 trading days immediately prior to date notice is provided is greater than $51.00. In such case, the number of common units to be issued upon conversion would be equal to the Per Unit Purchase Price plus the value of any accrued and unpaid distributions divided by an amount equal to a 7.5% discount to the VWAP for the 30 trading days immediately prior to the notice of conversion. Rather than have the Preferred Units convert to common units in accordance with the provisions of this paragraph, NRP would have the option to elect to redeem the Preferred Units proposed to be converted for cash at a price equal to Per Unit Purchase Price plus the value of any accrued and unpaid distributions.

On or after March 2, 2025, the holders of the Preferred Units may elect to convert the Preferred Units to common units at a conversion rate equal to the Liquidation Value divided by an amount equal to a 10% discount to the VWAP for the 30 trading days immediately prior to the notice of conversion. The “Liquidation Value” will be an amount equal to the greater of: (1) (a) the Per Unit Purchase Price multiplied by (i) prior to March 2, 2020, 1.50, (ii) on or after March 2, 2020 and prior to March 2, 2021, 1.70 and (iii) on or after March 2, 2021, 1.85, less (b)(i) all Preferred Unit distributions previously made by NRP and (ii) all cash payments previously made in respect of redemption of any PIK Units; and (2) the Per Unit Purchase Price plus the value of all accrued and unpaid distributions.

To the extent the holders of the Preferred Units have not elected to convert their Preferred Units before March 2, 2029, NRP has the right to force conversion of the Preferred Units at a price equal to the Liquidation Value divided by an amount equal to a 10% discount to the VWAP for the 30 trading days immediately prior to the notice of conversion.

In addition, NRP has the ability to redeem at any time (subject to compliance with its debt agreements) all or any portion of the Preferred Units and any outstanding PIK Units for cash. The redemption price for each outstanding PIK Unit is $1,000 plus the value of any accrued and unpaid distributions per PIK Unit. The redemption price for each Preferred Unit is the Liquidation Value divided by the number of outstanding Preferred Units. The Preferred Units are redeemable at the option of the Preferred Purchasers only upon a change in control.

The terms of the Preferred Units contain certain restrictions on NRP's ability to pay distributions on its common units. To the extent that either (i) NRP's consolidated Leverage Ratio, as defined in the Partnership's Fifth Amended and Restated Partnership Agreement dated March 2, 2017 (the "Restated Partnership Agreement"), is greater than 3.25x, or (ii) the ratio of NRP's Distributable Cash Flow (as defined in the Restated Partnership Agreement) to cash distributions made or proposed to be made is less than 1.2x (in each case, with respect to the most recently completed four-quarter period), NRP may not increase the quarterly distribution above $0.45 per quarter without the approval of the holders of a majority of the outstanding Preferred Units. In addition, if at any time after January 1, 2022, any PIK Units are outstanding, NRP may not make distributions on its common units until it has redeemed all PIK Units for cash.

The holders of the Preferred Units have the right to vote with holders of NRP’s common units on an as-converted basis and have other customary approval rights with respect to changes of the terms of the Preferred Units. In addition, Blackstone has certain approval rights over certain matters as identified in the Restated Partnership Agreement. GoldenTree also has more limited approval rights that will expand once Blackstone's ownership goes below the Minimum Preferred Unit Threshold (as defined below). These approval rights are not transferrable without NRP's consent. In addition, the approval rights held by Blackstone and GoldenTree will terminate at such time that Blackstone (together with their affiliates) or GoldenTree (together with their affiliates), as applicable, no longer own at least 20% of the total number of Preferred Units issued on the closing date, together with all PIK Units that have been issued but not redeemed (the "Minimum Preferred Unit Threshold").

At the closing, pursuant to the Board Representation and Observation Rights Agreement, the Preferred Purchasers received certain board appointment and observation rights, and Blackstone appointed one director and one observer to the Board of Directors of GP Natural Resource Partners LLC.

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NRP also entered into a registration rights agreement (the "Preferred Unit and Warrant Registration Rights Agreement") with the Preferred Purchasers, pursuant to which NRP is required to file (i) a shelf registration statement to register the common units issuable upon exercise of the Warrants and to cause such registration statement to become effective not later than 90 days following the closing date and (ii) a shelf registration statement to register the common units issuable upon conversion of the Preferred Units and to cause such registration statement to become effective not later than the earlier of the fifth anniversary of the closing date or 90 days following the first issuance of any common units upon conversion of Preferred Units (the "Registration Deadlines"). In addition, the Preferred Unit and Warrant Registration Rights Agreement gives the Preferred Purchasers piggyback registration and demand underwritten offering rights under certain circumstances. The shelf registration statement to register the common units issuable upon exercise of the Warrants became effective on April 20, 2017. If the shelf registration statement to register the common units issuable upon conversion of the Preferred Units is not effective by the applicable Registration Deadline, NRP will be required to pay the Preferred Purchasers liquidated damages in the amounts and upon the term set forth in the Preferred Unit and Warrant Registration Rights Agreement.

Accounting for the Preferred Units and Warrants

Classification

The Preferred Units are accounted for on NRP's consolidated balance sheets as temporary equity due to certain contingent redemption rights that may be exercised at the election of Preferred Purchasers. The Warrants are accounted for on NRP's consolidated balance sheets as equity.

Initial Measurement

The net transaction price as shown below was allocated to the Preferred Units and Warrants based on their relative fair values at inception date. NRP allocated the transaction issuance costs to the Preferred Units and Warrants primarily on a pro-rata basis based on their relative inception date allocated values. The Preferred Units and Warrants were initially recognized as follows:

(In thousands)	March 2, 2017
Transaction price, gross	$250,000
Structuring, origination and other fees to Preferred Purchasers	(7,900)
Transaction costs to other third parties	(10,697)
Transaction price, net	$231,403
Allocation of net transaction price	
Preferred Units, net	$164,587
Warrant holders interest, net	66,816
Transaction price, net	$231,403

Subsequent Measurement

Subsequent adjustment of the Preferred Units will not occur until NRP has determined that the conversion or redemption of all or a portion of the Preferred Units is probable of occurring. Once conversion or redemption becomes probable of occurring, the carrying amount of the Preferred Units will be accreted to their redemption value over the period from the date the feature is probable of occurring to the date the Preferred Units can first be converted or redeemed.

During the three months ended March 31, 2018, the Partnership redeemed all of the outstanding PIK Units, which resulted in an $8.8 million cash payment during the period.
Activity related to the Preferred Units is as follows:

(In thousands, except unit data)	Units Outstanding	Financial Position
Balance at December 31, 2016	—	$—
Issuance of Preferred Units, net	250,000	164,587
Distribution paid-in-kind	8,844	8,844
Balance at December 31, 2017	258,844	$173,431
Redemption of PIK Units	(8,844)	(8,844)
Balance at December 31, 2018	250,000	$164,587

Subsequent adjustment of the Warrants will not occur until the Warrants are exercised, at which time, NRP may, at its option, elect to settle the Warrants in common units or cash, each on a net basis. The net basis will be equal to the difference between the Partnership's common unit price and the strike price of the Warrant. Once Warrant exercise occurs, the difference between the carrying amount of the Warrants and the net settlement amount will be allocated on a pro-rata basis to the common unitholders and general partner.

Certain embedded features within the Preferred Unit and Warrant purchase agreement are accounted for at fair value and are remeasured each quarter. See Note 14. Fair Value Measurements for further information regarding valuation of these embedded derivatives.

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6. Common and Preferred Unit Distributions

The Partnership makes cash distributions to common unit holders on a quarterly basis, subject to approval by the Board of Directors. As discussed in Note 5. Class A Convertible Preferred Units and Warrants above, the Partnership also makes distributions to the preferred unitholders. NRP recognizes both Common and Preferred Unit distributions on the date the distribution is declared.

Common Unit Distributions

Distributions made on the common units and the general partner's general partner ("GP") interest are made on a pro-rata basis in accordance with their relative percentage interests in the Partnership. The general partner is entitled to receive 2% of such distributions. The following table shows the distributions declared and paid to common unitholders during the years ended December 31, 2018, 2017 and 2016, respectively:

			Total Distributions (in thousands)		
Date Paid	Period Covered by Distribution	Distribution per Common Unit	Common Units	GP Interest	Total
2018					
February 14, 2018	October 1 - December 31, 2017	$ 0.45	$5,505	$ 112	$5,617
May 14, 2018	January 1 - March 31, 2018	0.45	5,510	113	5,623
August 14, 2018	April 1 - June 30, 2018	0.45	5,511	112	5,623
November 14, 2018	July 1 - September 30, 2018	0.45	5,510	113	5,623
2017					
February 14, 2017	October 1 - December 31, 2016	$ 0.45	$5,503	$ 112	$5,615
May 12, 2017	January 1 - March 31, 2017	0.45	5,506	113	5,619
August 14, 2017	April 1 - June 30, 2017	0.45	5,504	112	5,616
November 14, 2017	July 1 - September 30, 2017	0.45	5,505	112	5,617
2016					
February 12, 2016	October 1 - December 31, 2015	$ 0.45	$5,503	$ 113	$5,616
May 13, 2016	January 1 - March 31, 2016	0.45	5,503	113	5,616
August 12, 2016	April 1 - June 30, 2016	0.45	5,505	112	5,617
November 14, 2016	July 1 - September 30, 2016	0.45	5,503	113	5,616

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Preferred Unit Distributions

The following table shows the distributions declared and paid to Preferred Unitholders during the years ended December 31, 2018 and 2017:

Date Paid	Period Covered by Distribution	Distribution per Preferred Unit	Total Distribution Declared (in thousands)
2018			
February 7, 2018	October 1 - December 31, 2017	$ 30.00	$ 7,765
May 14, 2018	January 1 - March 31, 2018	30.00	7,500
August 14, 2018	April 1 - June 30, 2018	30.00	7,500
November 14, 2018	July 1 - September 30, 2018	30.00	7,500
2017			
May 30, 2017	March 2 - March 31, 2017	$ 5.00	$ 2,500
August 29, 2017	April 1 - June 30, 2017	15.00	7,538
November 29, 2017	July 1 - September 30, 2017	15.00	7,650

Income available to common unitholders and the general partner is reduced by Preferred Unit distributions that accumulated during the period. During the year ended December 31, 2018 and 2017, NRP reduced net income attributable to common unitholders and the general partner by $30.0 million and $25.5 million, respectively as a result of accumulated Preferred Unit distributions earned during the period. The $7.5 million preferred unit distribution earned during the three months ended December 31, 2018 was paid on February 14, 2019.

7. Net Income Per Common Unit

Basic net income per common unit is computed by dividing net income, after considering income attributable to non-controlling interest, preferred unitholders and the general partner’s general partner interest, by the weighted average number of common units outstanding. Diluted net income per common unit includes the effect of NRP's Preferred Units and Warrants, if the inclusion of these items is dilutive.

The dilutive effect of the Preferred Units is calculated using the if-converted method. Under the if-converted method, the Preferred Units are assumed to be converted at the beginning of the period, and the resulting common units are included in the denominator of the diluted net income per unit calculation for the period being presented. Distributions declared in the period and undeclared distributions on the Preferred Units that accumulated during the period are added back to the numerator for purposes of the if-converted calculation.

The dilutive effect of the Warrants is calculated using the treasury stock method, which assumes that the proceeds from the exercise of these instruments are used to purchase common units at the average market price for the period. The calculation of the dilutive effect of the Warrants for the years ended December 31, 2018 and 2017 includes the net settlement of Warrants to purchase 1.75 million common units with a strike price of $22.81 but did not include the net settlement of Warrants to purchase 2.25 million common units with a strike price of $34.00 because the impact would have been anti-dilutive.

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The following table reconciles the numerators and denominators of the basic and diluted net income per common unit computations and calculates basic and diluted net income per common unit:

	Year Ended December 31,		
(In thousands, except per unit data)	2018	2017	2016
Allocation of net income:			
Net income from continuing operations	$122,360	$82,485	$90,626
Less: net income attributable to non-controlling interest	(510)	—	—
Less: income attributable to preferred unitholders	(30,000)	(25,453)	—
Net income from continuing operations attributable to common unitholders and general partner	$91,850	$57,032	$90,626
Less: net income from continuing operations attributable to the general partner	(1,837)	(1,141)	(1,537)
Net income from continuing operations attributable to common unitholders	$90,013	$55,891	$89,089
Net income from discontinued operations	$17,687	$6,182	$6,266
Less: net income from discontinued operations attributable to the general partner	(354)	(123)	(126)
Net income from discontinued operations attributable to common unitholders	$17,333	$6,059	$6,140
Net income	$140,047	$88,667	$96,892
Less: net income attributable to non-controlling interest	(510)	—	—
Less: income attributable to preferred unitholders	(30,000)	(25,453)	—
Net income attributable to common unitholders and general partner	$109,537	$63,214	$96,892
Less: net income attributable to the general partner	(2,191)	(1,264)	(1,663)
Net income attributable to common unitholders	$107,346	$61,950	$95,229
Basic income per common unit:			
Weighted average common units—basic	12,244	12,232	12,232
Basic net income from continuing operations per common unit	$7.35	$4.57	$7.28
Basic net income from discontinued operations per common unit	$1.42	$0.50	$0.50
Basic net income per common unit	$8.77	$5.06	$7.78

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	Year Ended December 31,		
(In thousands, except per unit data)	2018	2017	2016
Diluted income per common unit:			
Weighted average common units—basic	12,244	12,232	12,232
Plus: dilutive effect of Warrants	511	300	—
Plus: dilutive effect of Preferred Units	7,479	9,418	—
Weighted average common units—diluted	20,234	21,950	12,232
Net income from continuing operations	$122,360	$82,485	$90,626
Less: net income attributable to non-controlling interest	(510)	—	—
Diluted net income from continuing operations attributable to common unitholders and general partner	$121,850	$82,485	$90,626
Less: net income from continuing operations attributable to the general partner	(2,437)	(1,650)	(1,537)
Diluted net income from continuing operations attributable to common unitholders	$119,413	$80,835	$89,089
Diluted net income from discontinued operations attributable to common unitholders	$17,333	$6,059	$6,140
Net income	$140,047	$88,667	$96,892
Less: net income attributable to non-controlling interest	(510)	—	—
Diluted net income attributable to common unitholders and general partner	$139,537	$88,667	$96,892
Less: diluted net income attributable to the general partner	(2,791)	(1,773)	(1,663)
Diluted net income attributable to common unitholders	$136,746	$86,894	$95,229
Diluted net income from continuing operations per common unit	$5.90	$3.68	$7.28
Diluted net income from discontinued operations per common unit	$0.86	$0.28	$0.50
Diluted net income per common unit	$6.76	$3.96	$7.78

8. Segment Information

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

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

Soda Ash—consists of the Partnership's 49% non-controlling equity interest in Ciner Wyoming, a trona ore mining operation and soda ash refinery in the Green River Basin of Wyoming. Ciner Resources LP, the Partnership's operating partner, mines the trona, processes it into soda ash, and distributes the soda ash both domestically and internationally to the glass and chemicals industries.

In December 2018, the Partnership sold its construction aggregates business for $205 million, before customary purchase price adjustments and transaction expenses, and recorded a gain of $13.1 million. The Partnership's exit from the construction aggregates business enabled it to further reduce debt, focus on its Coal Royalty and Other and Soda Ash business segments and represented a strategic shift as it exited the operations of its construction aggregates business. The gain on sale and operating results of the construction aggregates business is included in Income from discontinued operations on the Consolidated Statements of Comprehensive Income and the net cash proceeds received is included in Cash provided by investing activities of discontinued operations in the Partnership's Consolidated Statements of Cash Flows for the year ended December 31, 2018. See Note 4. Discontinued Operations for more information.

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

Corporate and Financing includes functional corporate departments that do not earn revenues. Costs incurred by these departments include interest and financing, corporate headquarters and overhead, centralized treasury and accounting and other corporate-level activity not specifically allocated to a segment and are included in General and administrative expenses and General and administrative expenses—affiliates on the Consolidated Statements of Comprehensive Income.

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The following table summarizes certain financial information for each of the Partnership's business segments:

	Operating Segments			
(In thousands)	Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
For the Year Ended December 31, 2018				
Revenues (including affiliates)	$202,765	$48,306	$—	$251,071
Gain on litigation settlement	25,000	—	—	25,000
Gain on asset sales, net	2,441	—	—	2,441
Operating and maintenance expenses (including affiliates)	29,509	—	—	29,509
Depreciation, depletion and amortization	21,689	—	—	21,689
General and administrative (including affiliates)	—	—	16,496	16,496
Asset impairments	18,280	—	—	18,280
Other expense, net	—	—	70,178	70,178
Net income (loss) from continuing operations	160,728	48,306	(86,674)	122,360
Net income from discontinued operations	—	—	—	17,687
As of December 31, 2018				
Total assets of continuing operations	$986,680	$247,051	$106,923	$1,340,654
Total assets of discontinued operations	—	—	—	993
For the Year Ended December 31, 2017				
Revenues (including affiliates)	$202,323	$40,457	$—	$242,780
Gain on asset sales, net	3,545	—	—	3,545
Operating and maintenance expenses (including affiliates)	24,883	—	—	24,883
Depreciation, depletion and amortization (including affiliates)	23,414	—	—	23,414
General and administrative (including affiliates)	—	—	18,502	18,502
Asset impairments	2,967	—	—	2,967
Other expense, net	—	—	94,074	94,074
Net income (loss) from continuing operations	154,604	40,457	(112,576)	82,485
Net income from discontinued operations	—	—	—	6,182
As of December 31, 2017				
Total assets of continuing operations	$945,237	$245,433	$6,129	$1,196,799
Total assets of discontinued operations	—	—	—	192,365
For the Year Ended December 31, 2016				
Revenues (including affiliates)	$210,115	$40,061	$—	$250,176
Gain on asset sales, net	29,068	—	—	29,068
Operating and maintenance expenses (including affiliates)	29,890	—	—	29,890
Depreciation, depletion and amortization (including affiliates)	31,766	—	—	31,766

General and administrative (including affiliates)	—	—	20,570	20,570
Asset impairments	15,861	—	—	15,861
Other expense, net	—	—	90,531	90,531
Net income (loss) from continuing operations	161,666	40,061	(111,101)	90,626
Net income from discontinued operations	—	—	—	6,266
Capital expenditures	5	—	—	5

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9. Equity Investment

The Partnership accounts for its 49% investment in Ciner Wyoming using the equity method of accounting. Activity related to this investment is as follows:

	For the Year Ended December 31,		
(In thousands)	2018	2017	2016
Balance at beginning of period	$245,433	$255,901	$261,942
Income allocation to NRP's equity interests[1]	53,095	44,846	44,882
Amortization of basis difference	(4,789)	(4,389)	(4,821)
Comprehensive income (loss) from unconsolidated investment	(138)	(1,925)	448
Distribution	(46,550)	(49,000)	(46,550)
Balance at end of period	$247,051	$245,433	$255,901

(1) Includes reclassifications of accumulated other comprehensive loss to income allocation to NRP equity interest of $0.5 million, $0.7 million and $0.9 million for the year ended December 31, 2018, 2017 and 2016, respectively.

The difference between the amount at which the investment in Ciner Wyoming is carried and the amount of underlying equity in Ciner Wyoming's net assets was $140.8 million and $145.6 million as of December 31, 2018 and 2017, respectively. This excess basis relates to property, plant and equipment and right to mine assets. The excess basis difference that relates to property, plant and equipment is being amortized into income using the straight-line method over 28 years. The excess basis difference that relates to right to mine assets is being amortized into income using the units of production method.

The following table represents summarized financial information for Ciner Wyoming as derived from the respective financial statements for the years ended December 31, 2018, 2017, and 2016:

	For the Year Ended December 31,		
(In thousands)	2018	2017	2016
Sales	$486,759	$497,340	$475,187
Gross profit	104,053	114,202	114,232
Net income	108,357	91,523	91,596

The financial position of Ciner Wyoming is summarized as follows:

	December 31,	
(In thousands)	2018	2017
Current assets	$138,080	$180,433
Noncurrent assets	252,743	228,002
Current liabilities	64,012	56,219
Noncurrent liabilities	109,921	148,401

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10. Plant and Equipment, Net

The Partnership’s plant and equipment consist of the following:

	December 31,	
(In thousands)	2018	2017
Plant and equipment at cost	$6,865	$6,865
Less: accumulated depreciation	(5,881)	(5,517)
Total plant and equipment, net	$984	$1,348

Depreciation expense included in Depreciation, depletion and amortization on the Partnership's Consolidated Statements of Comprehensive Income totaled $0.4 million, $0.4 million and $0.8 million for the year ended December 31, 2018, 2017 and 2016, respectively.

Impairment expense related to the Partnership's plant and equipment included in Asset impairments on the Consolidated Statements of Comprehensive Income totaled $2.0 million for the year ended December 31, 2016.

11. Mineral Rights, Net

The Partnership’s mineral rights consist of the following:

	December 31, 2018		
(In thousands)	Carrying Value	Accumulated Depletion	Net Book Value
Coal properties	$1,164,845	$(451,210)	$713,635
Aggregates properties	24,920	(11,814)	13,106
Oil and gas royalty properties	12,395	(7,632)	4,763
Other	13,158	(1,550)	11,608
Total mineral rights, net	$1,215,318	$(472,206)	$743,112

	December 31, 2017		
(In thousands)	Carrying Value	Accumulated Depletion	Net Book Value
Coal properties	$1,170,104	$(436,964)	$733,140
Aggregates properties	37,942	(9,602)	28,340
Oil and gas royalty properties	12,395	(7,158)	5,237
Other	13,168	(1,466)	11,702
Total mineral rights, net	$1,233,609	$(455,190)	$778,419

Depletion expense related to the Partnership’s mineral rights is included in Depreciation, depletion and amortization on the Partnership's Consolidated Statements of Comprehensive Income and totaled $17.0 million, $20.1 million and $27.8 million for the year ended December 31, 2018, 2017 and 2016, respectively.

Sales of Mineral Rights

During the year ended December 31, 2018, the Partnership sold mineral reserves in its Coal Royalty and Other segment in multiple transactions for cumulative gross proceeds of $2.4 million and recorded a cumulative gain of $2.4 million included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income.

During the year ended December 31, 2017, the Partnership sold mineral reserves in its Coal Royalty and Other segment in multiple transactions for cumulative gross proceeds of $1.0 million and recorded a cumulative gain of $3.5 million included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income.

During the year ended December 31, 2016, the Partnership sold the following assets:
1)Oil and gas royalty and overriding royalty interests in the Coal Royalty and Other segment in several producing properties located in the Appalachian Basin for $36.4 million gross sales proceeds. The effective date of the sale was January 1, 2016, and the Partnership recorded an $18.6 million gain from this sale included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income.
2)Aggregates reserves and related royalty rights in the Coal Royalty and Other segment at three aggregates operations located in Texas, Georgia and Tennessee for $10.0 million gross sales proceeds. The effective date of the sale was February 1, 2016, and the Partnership recorded a $1.5 million gain from this sale included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income.
In addition to the two asset sales described above, during the year ended December 31, 2016, the Partnership sold mineral reserves within its Coal Royalty and Other segment in multiple sale transactions for $17.3 million of cumulative gross sales proceeds and recorded a cumulative gain of $8.6 million from these sale transactions that are included in Gain on asset sales, net on its Consolidated Statement of Comprehensive Income. These amounts primarily relate to eminent domain transactions with governmental agencies and the sale of additional oil and gas royalty interests.

Impairment of Mineral Rights

During the years ended December 31, 2018, 2017 and 2016, the Partnership identified facts and circumstances that indicated that the carrying value of certain of its mineral rights exceed future cash flows from those assets and recorded non-cash impairment expense included in Asset impairments on the Consolidated Statements of Comprehensive Income as follows:

	For the Years Ended December 31,		
(In thousands)	2018	2017	2016
Coal properties (1)	$5,259	$595	$12,088
Oil and gas properties	—	—	36
Aggregates and timber royalty properties (2)	13,021	2,372	1,677
Total	$18,280	$2,967	$13,801

(1) The Partnership recorded $5.3 million of coal property impairments during the year ended December 31, 2018 primarily as a result of lease terminations, of which it recorded $5.0 million of impairment expense to fully impair certain coal properties during the three months ended December 31, 2018. The Partnership recorded $0.6 million of coal property impairments during the year ended December 31, 2017. The Partnership recorded $12.1 million of coal property impairments during the year ended December 31, 2016 primarily as a result of lease surrender and termination. The Partnership recorded $3.8 million of coal property impairment during the three months ended September 30, 2016 and the fair value of the impaired asset was reduced to $4.0 million at September 30, 2016. The Partnership recorded $8.2 million of impairment expense to fully impair certain coal property impairment during the three months ended December 31, 2016.

(2) During the three months ended December 31, 2018, the Partnership recorded $13.0 million of impairment expense related to an aggregates property that the Partnership owns and leases to its former construction aggregates business, which mines, produces and sells the aggregates. The fair value of the impaired asset was reduced to $2.3 million at December 31, 2018. The Partnership recorded $2.4 million and $1.7 million of aggregates and timber royalty properties impairments during the year ended December 31, 2017 and 2016, respectively.

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12. Intangible Assets, Net

The Partnership's intangible assets consist of above-market coal and related transportation contracts with subsidiaries of Foresight Energy in which the Partnership receives throughput fees for the handling and transportation of coal. The Partnership's intangible assets included on its Consolidated Balance Sheets are as follows:

	December 31,	
(In thousands)	2018	2017
Intangible assets	$81,109	$81,109
Less: accumulated amortization	(38,596)	(34,289)
Total intangible assets, net	$42,513	$46,820

Amortization expense included in Depreciation, depletion and amortization on the Partnership's Consolidated Statements of Comprehensive Income was $4.3 million and $2.0 million for the years ended December 31, 2018 and 2017, respectively. Amortization expense included in Amortization expense—affiliates on the Partnership's Consolidated statements of Comprehensive income was $1.0 million and $3.2 million for the years ended December 31, 2017 and 2016, respectively. As of May 9, 2017, Foresight Energy was no longer deemed to be an affiliate of the Partnership. Refer to Note 15. Related Party Transactions for additional details.

The estimates of amortization expense for the years ended December 31, as indicated below, are based on current mining plans and are subject to revision as those plans change in future periods.

(In thousands)	Estimated Amortization Expense
2019	$ 3,251
2020	3,741
2021	3,660
2022	3,636
2023	3,602

The weighted average remaining amortization period for contract intangibles was 16 years.

13. Debt, Net

The Partnership's debt consists of the following:

	December 31,	
(In thousands)	2018	2017
NRP LP debt:		
10.500% senior notes, with semi-annual interest payments in March and September, due March 2022, $241 million issued at par and $105 million issued at 98.75%	$345,638	$345,638
Opco debt:		
Revolving credit facility	—	60,000
Senior notes		
4.91% with semi-annual interest payments in June and December, with annual principal payments in June, due June 2018	—	4,586
8.38% with semi-annual interest payments in March and September, with annual principal payments in March, due March 2019	21,319	42,670
5.05% with semi-annual interest payments in January and July, with annual principal payments in July, due July 2020	15,290	22,946
5.55% with semi-annual interest payments in June and December, with annual principal payments in June, due June 2023	13,414	16,115
4.73% with semi-annual interest payments in June and December, with annual principal payments in December, due December 2023	37,195	44,693
5.82% with semi-annual interest payments in March and September, with annual principal payments in March, due March 2024	89,529	104,520
8.92% with semi-annual interest payments in March and September, with annual principal payments in March, due March 2024	27,185	31,733
5.03% with semi-annual interest payments in June and December, with annual principal payments in December, due December 2026	107,013	120,547
5.18% with semi-annual interest payments in June and December, with annual principal payments in December, due December 2026	30,555	34,396
Total debt at face value	$687,138	$827,844
Net unamortized debt discount	(1,266)	(1,661)
Net unamortized debt issuance costs	(13,114)	(16,835)
Total debt, net	$672,758	$809,348
Less: current portion of long-term debt	115,184	79,740
Total long-term debt, net	$557,574	$729,608

NRP LP Debt

2022 Senior Notes

In March 2017, NRP and NRP Finance issued $346 million aggregate principal amount of 2022 Senior Notes to several holders of their 2018 Senior Notes. Of the $346 million of 2022 Senior Notes issued, $241 million in aggregate principal amount were issued in exchange for $241 million in aggregate principal amount of 2018 Senior Notes, and $105 million of the 2022 Senior Notes were issued to the holders for cash. The 2022 Senior Notes are issued under an Indenture dated as of March 2, 2017 (the "Indenture"), bear interest at 10.500% per year, are payable semi-annually on March 15 and September 15, beginning September 15, 2017, and mature on March 15, 2022. The $105.0 million in 2022 Senior Notes purchased for cash were issued at a price of 98.75% (original issue discount of 1.25%), and each holder exchanging 2018 Senior Notes received a fee of 5.813% of the aggregate principal amount of all 2018 Senior Notes tendered for exchange by such holder, as well as all accrued and unpaid interest thereon. The 5.813% fee included a 4.563% call premium on the early repayment of the 2018 Senior Notes and a 1.25% fee on the exchange of the 2018 Notes for 2022 Senior Notes. This fee is accounted for as a debt issuance cost, capitalized and shown net of the debt liability on the Partnership's Consolidated Balance Sheets.

NRP and NRP Finance have the option to redeem the 2022 Senior Notes, in whole or in part, at any time on or after March 15, 2019, at the redemption prices (expressed as percentages of principal amount) of 105.25% for the 12-month period beginning March 15, 2019, 102.625% for the 12-month period beginning March 15, 2020, and thereafter at 100.000%, together, in each case, with any accrued and unpaid interest to the date of redemption. Furthermore, before March 15, 2019, NRP may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2022 Senior Notes with the net proceeds of certain public or private equity offerings at a redemption price of 110.500% of the principal amount of 2022 Senior Notes, plus any accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the aggregate principal amount of the 2022 Senior Notes issued under the 2022 Indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. In the event of a change of control, as defined in the 2022 Indenture, the holders of the 2022 Senior Notes may require the Partnership to purchase their 2022 Senior Notes at a purchase price equal to 101% of the principal amount of the 2022 Senior Notes, plus accrued and unpaid interest, if any.
The 2022 Indenture contains restrictive covenants that are substantially similar to those contained in the Indenture governing the 2018 Senior Notes, except that the debt incurrence and restricted payments covenants contain additional restrictions. Under the debt incurrence covenant, NRP's non-guarantor restricted subsidiaries will not be permitted to incur additional indebtedness unless their consolidated leverage ratio is less than 3.00x (measured on a pro forma basis and assuming that the greater of (i) $150.0 million of debt (or, if less, at NRP's election, the amount of total lending commitments under any revolving credit facility) and (ii) the actual amount of debt outstanding is outstanding under any revolving credit facility); provided, however, that such non-guarantor restricted subsidiaries will be permitted to make up to $150 million in borrowings under a revolving credit facility (which amount will be reduced on a dollar-for-dollar basis to the extent NRP has made the election described in clause (i) above). Under the restricted payments covenant, NRP will not be able to increase the quarterly distribution on its common units or elect to pay more than 50% of the distributions required to be made on the Preferred Units in cash, unless, in each case, its consolidated leverage ratio is less than 4.00x. The 2022 Indenture also contains restrictions on NRP's ability to redeem the Preferred Units.

The 2022 Senior Notes are the senior unsecured obligations of NRP and NRP Finance. The 2022 Senior Notes rank equal in right of payment to all existing and future senior unsecured debt of NRP and NRP Finance and senior in right of payment to any of NRP's subordinated debt. The 2022 Senior Notes are effectively subordinated in right of payment to all future secured debt of NRP and NRP Finance to the extent of the value of the collateral securing such indebtedness and are structurally subordinated in right of payment to all existing and future debt and other liabilities of our subsidiaries, including the Opco Credit Facility and each series of Opco’s existing Senior Notes, as defined below. None of NRP's subsidiaries guarantee the 2022 Senior Notes.

As of December 31, 2018 and December 31, 2017, NRP and NRP Finance were in compliance with the terms of their debt agreements.

Opco Debt

All of Opco’s debt is guaranteed by its wholly owned subsidiaries and is secured by certain of the assets of Opco and its wholly owned subsidiaries other than NRP Trona LLC. As of December 31, 2018 and 2017, Opco was in compliance with the terms of the financial covenants contained in its debt agreements.

Opco Credit Facility

Opco’s Third Amended and Restated Credit Agreement, as amended (the "Opco Credit Facility"), matures on April 30, 2020. As of December 31, 2018, Opco had $100 million in available borrowing capacity under the Opco Credit Facility. As discussed in Note 4. Discontinued Operations, in December 2018 the Partnership repaid the outstanding balance of the Opco Credit Facility as a result of the sale of its construction aggregates business.

Indebtedness under the Opco Credit Facility bears interest, at Opco's option, at:

- the higher of (i) the prime rate as announced by the agent bank; (ii) the federal funds rate plus 0.50%; or (iii) LIBOR plus 1%, in each case plus an applicable margin ranging from 2.50% to 3.50%; or
- a rate equal to LIBOR plus an applicable margin ranging from 3.50% to 4.50%.

The weighted average interest rates for the borrowings outstanding under the Opco Credit Facility for the years ended December 31, 2018 and 2017 were 6.23% and 5.32%, respectively. Debt issuance costs related to the OpCo credit facility were $1.7 million and $4.6 million at December 31, 2018 and 2017, respectively and have been capitalized and included in Other assets on the Partnership's Consolidated Balance Sheets. Opco will incur a commitment fee on the unused portion of the revolving credit facility at a rate of 0.50% per annum. Opco may prepay all amounts outstanding under the Opco Credit Facility at any time without penalty.

The Opco Credit Facility contains financial covenants requiring Opco to maintain:

- a leverage ratio of consolidated indebtedness to EBITDDA (as defined in the Opco Credit Facility) not to exceed 4.0x; provided, however, that if NRP increases its quarterly distribution to its common unitholders above $0.45 per common unit, the maximum leverage ratio under the Opco Credit Facility will permanently decrease from 4.0x to 3.0x; and
- a fixed charge coverage ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease expense) of not less than 3.5 to 1.0.

The Opco Credit Facility contains certain additional customary negative covenants that, among other items, restrict Opco's ability to incur additional debt, grant liens on its assets, make investments, sell assets and engage in business combinations. Included in the investment covenant are restrictions upon Opco's ability to acquire assets where Opco does not maintain certain levels of liquidity. In addition, Opco is required to use 75% of the net cash proceeds of certain non-ordinary course asset sales to repay the Opco Credit Facility (without any corresponding commitment reduction) and use the remaining 25% of the net cash proceeds to offer to repay its Senior Notes on a pro-rata basis, as described below under "—Opco Senior Notes." The Opco Credit Facility also contains customary events of default, including cross-defaults under Opco's Senior Notes.

The Opco Credit Facility is collateralized and secured by liens on certain of Opco's assets with carrying values of $548.9 million and $553.9 million classified as Plant and equipment and Mineral rights as of December 31, 2018 and 2017, respectively, and $95.7 million included in Long-term assets of discontinued operations on the Partnership's Consolidated Balance Sheets as of December 31, 2017. The collateral includes (1) the equity interests in all of Opco's wholly owned subsidiaries, other than NRP Trona LLC (which owns a 49% non-controlling equity interest in Ciner Wyoming), (2) the personal property and fixtures owned by Opco's wholly owned subsidiaries, other than NRP Trona LLC, (3) Opco's material coal royalty revenue producing properties, and (4) certain of Opco's coal-related infrastructure assets.

Opco Senior Notes

Opco has issued several series of private placement senior notes (the "Opco Senior Notes") with various interest rates and principal due dates. As of December 31, 2018 and 2017, the Opco Senior Notes had cumulative principal balances of $341.5 million and $422.2 million, respectively. Opco made mandatory principal payments on the Opco Senior Notes of $80.7 million, $80.8 million and $82.9 million for the years ended December 31, 2018, 2017 and 2016, respectively. As discussed in Note 4. Discontinued Operations, as a result of the sale of the Partnership's construction aggregates business, $49 million was offered to the holders of the Opco Senior Notes and paid during the first quarter of 2019. The remaining $55 million of net cash proceeds from the sale of the construction aggregates business is restricted and the Partnership intends to use these remaining proceeds to repay its Opco Senior Notes as they amortize in 2019.

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

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

In addition, the Note Purchase Agreements include a covenant that provides that, in the event NRP Operating or any of its subsidiaries is subject to any additional or more restrictive covenants under the agreements governing its material indebtedness (including the Opco Credit Facility and all renewals, amendments or restatements thereof), such covenants shall be deemed to be incorporated by reference in the Note Purchase Agreements and the holders of the Notes shall receive the benefit of such additional or more restrictive covenants to the same extent as the lenders under such material indebtedness agreement.

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The 8.38% and 8.92% Opco Senior Notes also provide that in the event that Opco's leverage ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the Note Purchase Agreements) exceeds 3.75 to 1.00 at the end of any fiscal quarter, then in addition to all other interest accruing on these notes, additional interest in the amount of 2.00% per annum shall accrue on the notes for the two succeeding quarters and for as long thereafter as the leverage ratio remains above 3.75 to 1.00. Opco has not exceeded the 3.75 to 1.00 ratio at the end of any fiscal quarter through December 31, 2018.

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

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

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

Consolidated Principal Payments

The consolidated principal payments due are set forth below:

(In thousands)	NRP LP Senior Notes (1)	Opco Senior Notes	Credit Facility	Total
2019	$ —	$116,125	$ —	$116,125
2020	—	46,436	—	46,436
2021	—	39,634	—	39,634
2022	345,638	39,634	—	385,272
2023	—	39,634	—	39,634
Thereafter	—	60,037	—	60,037
	$ 345,638	$341,500	$ —	$687,138

(1) The 10.500% senior notes due 2022 were issued at a discount and were carried at $344.4 million and $344.0 million as of December 31, 2018 and 2017, respectively.

14. Fair Value Measurements

Fair Value of Financial Assets and Liabilities

The Partnership’s financial assets and liabilities consist of cash and cash equivalents, restricted cash, contracts receivable, debt, Preferred Units and Warrants. The carrying amounts reported on the Consolidated Balance Sheets for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature. There were no transfers between Level 1, Level 2 or Level 3 of the fair value hierarchy during the years ended December 31, 2018 or 2017.

The Partnership uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Partnership would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Partnership's default or repayment risk. The following table shows the carrying amount and estimated fair value of the Partnership's debt and contracts receivable:

	December 31, 2018		December 31, 2017	
(In thousands)	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Debt:				
NRP 2022 Senior Notes (1)	$334,024	$356,871	$330,404	$366,376
Opco Senior Notes (2)	338,734	352,599	418,944	447,538
Opco Revolving Credit Facility (3)	—	—	60,000	60,000
Assets:				
Contracts receivable, current and long-term (4)	$40,776	$34,704	$43,826	$30,517

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

(2) Due to no observable quoted prices on these instruments, the Level 3 fair value is estimated by management using quotations obtained for the NRP Senior Notes on the closing trading prices near period end.

(3) The Level 3 fair value approximates the outstanding borrowing amount because the interest rates are variable and reflective of market rates and the terms of the credit facility allow the Partnership to repay this debt at any time without penalty.

(4) The Level 3 fair value is determined based on the present value of future cash flow projections related to the underlying assets.

NRP has embedded derivatives in the Preferred Units related to certain conversion options, redemption features and the change of control provision that are accounted for separately from the Preferred Units as assets and liabilities at fair value on the Partnership's Consolidated Balance Sheets. Level 3 valuation of the embedded derivatives are based on numerous factors including the likelihood of the event occurring. The embedded derivatives are revalued quarterly, and changes in their fair value would be recorded in Other expense, net in the Partnership's Consolidated Statements of Comprehensive Income. The embedded derivatives had zero value as of December 31, 2018 and 2017.

Fair Value of Non-Financial Assets

The Partnership discloses or recognizes its non-financial assets, such as impairments of coal and aggregates properties and other assets, at fair value on a nonrecurring basis. Refer to <u>Note 10. Plant and Equipment, Net</u> and <u>Note 11. Mineral Rights, Net</u> for additional disclosures related to the fair value associated with the impaired assets.

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15. Related Party Transactions

Cline Affiliates and Foresight Energy

Mr. Chris Cline, both individually and through another affiliate, Adena Minerals, LLC ("Adena"), owned a 31% interest in NRP (GP) LP, NRP's general partner ("NRP GP"), through May 9, 2017. On May 9, 2017, Adena sold its 31% limited partner interest in NRP GP to Great Northern Properties Limited Partnership (“GNPLP”) and Western Pocahontas Properties Limited Partnership ("WPPLP") (the “Adena Sale”). GNPLP and WPPLP are companies controlled by Corbin J. Robertson, the Chairman and Chief Executive Officer of GP Natural Resource Partners LLC (the general partner of NRP GP) (“GP LLC”). Upon closing of this transaction, NRP no longer considers the various companies affiliated with Chris Cline, including Foresight Energy to be affiliates of NRP. As a result, all transactions (including revenues, expenses and cash flows) after May 9, 2017 with the various companies affiliated with Chris Cline, including Foresight Energy, are considered to be third party transactions.
Revenues and expenses related to transactions with Foresight Energy are included in the Partnership's Consolidated Statements of Comprehensive Income as follows:

	For the Years Ended December 31,		
(In thousands)	2018	2017	2016
Revenues:			
Coal royalty and other	$30,777	$28,763	$—
Coal royalty and other—affiliates	—	21,204	44,019
Transportation and processing services	23,818	14,510	—
Transportation and processing services—affiliates	—	6,012	19,336
Total	$54,595	$70,489	$63,355
Expenses:			
Operating and maintenance expense	$1,761	$1,066	$—
Operating and maintenance expense—affiliates	—	452	1,347
Total	$1,761	$1,518	$1,347

Coal Royalty and Other Revenues

Various subsidiaries of Foresight Energy lease coal reserves from the Partnership. In addition, NRP owns a contractual overriding royalty interest at Foresight Energy's Sugar Camp mine in the Illinois Basin which provides for payments based upon production from specific tons at Foresight Energy's Sugar Camp operations on certain reserves owned by another affiliate of Chris Cline. This overriding royalty is accounted for as a financing arrangement. Revenues related to these transactions are included in Coal royalty and other revenues in the Partnership's Consolidated Statements of Comprehensive Income.

Transportation and Processing Services Revenues and Expenses

The Partnership owns transportation and processing infrastructure related to certain of its coal properties, including loadout and other transportation assets at Foresight Energy's Williamson and Macoupin mines in the Illinois Basin, for which it collects throughput fees. These fees are included in Transportation and processing services revenues in the Partnership's Consolidated Statements of Comprehensive Income.

NRP is responsible for operating and maintaining the rail loadout transportation assets at the Williamson mine and subcontracts the operating responsibilities to a subsidiary of Foresight Energy. Expenses related to these operations are included in Operating and maintenance expenses in the Partnership's Consolidated Statements of Comprehensive Income.

In addition, NRP owns rail loadout and associated infrastructure at the Sugar Camp mine, an Illinois Basin mine also operated by a subsidiary of Foresight Energy LP. While the Partnership owns coal reserves at the Williamson and Macoupin mines, it does not own coal reserves at the Sugar Camp mine. The infrastructure at the Sugar Camp mine is leased to a subsidiary of Foresight Energy and NRP collects throughput fees, which are included in Transportation and processing services revenues in the Partnership's Consolidated Statements of Comprehensive Income.

NRP's Sugar Camp rail loadout lease with a subsidiary of Foresight Energy is accounted for as a financing lease. Minimum lease payments are $5.0 million per year for the next five years and represent a $1.25 million per quarter deficiency payment. The following table shows certain amounts related to NRP's Sugar Camp rail loadout facility financing lease:

	December 31,	
(In thousands)	2018	2017
Projected remaining payments	$66,495	$71,452
Unearned income	25,058	28,366

Reimbursements to Affiliates of our General Partner

The Partnership's general partner does not receive any management fee or other compensation for its management of NRP. However, in accordance with the partnership agreement, the general partner and its affiliates are reimbursed for services provided to the Partnership and for expenses incurred on the Partnership's behalf. Employees of Quintana Minerals Corporation ("QMC") and WPPLP, affiliates of the Partnership, provide their services to manage the Partnership's business. QMC and WPPLP charge the Partnership the portion of their employee salary and benefits costs related to their employee services provided to NRP. These QMC and WPPLP employee management service costs are presented as Operating and maintenance expenses—affiliates and General and administrative—affiliates on the Partnership's Consolidated Statements of Comprehensive Income. NRP also reimburses overhead costs incurred by its affiliates to manage the Partnership's business. These overhead costs include certain rent, legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by or on behalf of the Partnership's general partner and its affiliates and are presented as Operating and maintenance expenses—affiliates and General and administrative—affiliates on the Partnership's Consolidated Statements of Comprehensive Income.

Direct general and administrative expenses charged to the Partnership by QMC and WPPLP are included in the Partnership's Consolidated Statement of Comprehensive Income as follows:

	For the Years Ended December 31,		
(In thousands)	2018	2017	2016

Operating and maintenance expenses—affiliates	$6,170	$6,184	$8,119
General and administrative—affiliates	3,658	4,989	3,591

During the years ended December 31, 2018, 2017 and 2016, the Partnership recognized $5.4 million, $1.5 million and $0.7 million in Operating and maintenance expenses—affiliates, respectively, on its Consolidated Statements of Comprehensive Income related to a non-participating production royalty payable to WPPLP pursuant to a conveyance agreement entered into in 2007 in which coal royalty revenues received from a third party by NRP are passed back to WPPLP.

Included in Income from discontinued operations on the Partnership's Consolidated Statements of Income are $1.0 million, $1.4 million and $3.1 million of Operating and maintenance expenses charged by QMC for the years ended December 31, 2018, 2017 and 2016, respectively.

At December 31, 2017, the Partnership had Other assets—affiliate from WPPLP on its Consolidated Balance Sheets related to a non-production royalty receivable from WPPLP for overriding royalty interest of $0.2 million. The Partnership had Accounts payable—affiliates on its Consolidated Balance Sheets to QMC of $0.5 million and WPPLP of $1.4 million as of December 31, 2018 and to QMC of $0.4 million and WPPLP of $0.1 million as of December 31, 2017.
Included in Liabilities from discontinued operations on the Partnerships Consolidated Balance Sheets is $0.1 million in Accounts payable, affiliates, due to QMC as of December 31, 2018 and 2017, respectively.

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd. ("Quintana Capital"), which controls several private equity funds focused on investments in the energy business. In connection with the formation of Quintana Capital, the Partnership adopted a formal conflicts policy that establishes the opportunities that will be pursued by the Partnership and those that will be pursued by Quintana Capital. The governance documents of Quintana Capital's affiliated investment funds reflect the guidelines set forth in the Partnership's conflicts policy. At December 31, 2018, a fund controlled by Quintana Capital owned a substantial interest in Corsa Coal Corp. ("Corsa"), a coal mining company traded on the TSX Venture Exchange that is one of the Partnership's lessees in Tennessee. During the second quarter of 2018, Corsa assigned its lease with NRP to a third party and is no longer deemed a related party.
Coal related revenues from Corsa totaled $0.5 million, $1.3 million and $2.2 million for the years ended December 31, 2018, 2017 and 2016. At December 31, 2017, the Partnership had Accounts receivable—affiliates totaling $0.2 million from Corsa on its Consolidated Balance Sheet.

Quinwood Coal Company Royalty

In May 2017, a subsidiary of Alpha Natural Resources assigned two coal leases with us to Quinwood Coal Company ("Quinwood"), an entity wholly owned by Corbin J. Robertson III. In connection with this lease assignment, Quinwood forfeited the historical recoupable balance related to this property. As a result, NRP recognized $0.9 million of deferred minimum payments received in prior periods from a subsidiary of Alpha as Coal royalty and other—affiliates revenue on its Consolidated Statements of Comprehensive Income during the year ended December 31, 2017.

16. Major Customers

Revenues from customers that exceeded 10 percent of total revenues for any of the periods presented below are as follows:

	For the Years Ended December 31,					
	2018		2017		2016	
(In thousands)	Revenues	Percent	Revenues	Percent	Revenues	Percent
Foresight Energy	$54,595	21.7 %	$70,489	29.0 %	$63,355	25.3 %

Revenues from Foresight Energy are included within the Partnership's Coal Royalty and Other segment.

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17. Commitments and Contingencies

Legal

NRP is involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, Partnership management believes these claims will not have a material effect on the Partnership’s financial position, liquidity or operations. During the year ended 2018, NRP was also involved in the matters described below.

Anadarko Contingent Consideration Payment Dispute

In January 2013, NRP acquired a non-controlling 48.51% general partner interest in OCI Wyoming, L.P. ("OCI LP") and all of the preferred stock and a portion of the common stock of OCI Wyoming Co. ("OCI Co") (which in turn owned a 1% limited partner interest in OCI LP) from Anadarko Holding Company and its subsidiary, Big Island Trona Company (together, "Anadarko"). The remaining general partner interest in OCI LP and common stock of OCI Co were owned by subsidiaries of OCI Chemical Corporation.

The acquisition agreement provided for additional contingent consideration of up to $50 million to be paid by NRP if certain performance criteria were met at OCI LP as defined in the purchase and sale agreement in any of the years 2013, 2014 or 2015. For those years, NRP paid an aggregate of $11.5 million to Anadarko in full satisfaction of these contingent consideration payment obligations.

In July 2013, pursuant to a series of transactions in connection with an initial public offering by a subsidiary of OCI Chemical Corporation, the ownership structure in OCI LP was simplified. In connection with such reorganization, NRP exchanged the stock of OCI Co for a limited partner interest in OCI LP. Following the reorganization, NRP's interest in OCI LP increased to 49%, consisting of both limited and general partner interests. The restructuring did not have any impact on the operations, revenues, management or control of OCI LP.

In July 2017, Anadarko filed a lawsuit against Opco and NRP Trona LLC in the District Court of Harris County, Texas, 157th Judicial District. The complaint alleged that the transactions conducted in 2013 triggered an acceleration of NRP's obligation under the purchase agreement with Anadarko to pay additional contingent consideration in full and demanded immediate payment of such amount, together with interest, court costs and attorneys’ fees. NRP does not believe the reorganization transactions triggered an obligation to pay any additional contingent consideration and is vigorously defending this lawsuit. However, the ultimate outcome cannot be predicted with certainty and the Partnership estimates a possible range of loss between $0, if it prevails, and approximately $40 million, plus interest, court costs and attorneys’ fees if Anadarko prevails and is awarded the full damages it seeks.

Foresight Energy Settlement

In October 2018, NRP's lawsuits against Foresight Energy and its subsidiaries Hillsboro Energy and Macoupin Energy were settled. The Hillsboro suit was pending in the Circuit Court of the Fourth Judicial Circuit in Montgomery County, Illinois, and the Macoupin suit was pending in Macoupin County, Illinois. NRP received a payment of $25 million from Foresight Energy in full settlement of the Hillsboro litigation, which was recognized immediately as Gain on litigation settlement in the Consolidated Statement of Comprehensive Income. In addition, NRP and Hillsboro Energy amended the coal mining lease with respect to the Deer Run mine to change the $30 million recoupable annual minimum royalty payments to $11 million non-recoupable annual minimum payments effective

January 1, 2019 and extended the current lease term through the end of 2033. Furthermore, Foresight Energy forfeited its recoupable balances under the Macoupin and Hillsboro leases totaling approximately $37.4 million, the majority of which NRP previously recognized in Cumulative effect of adoption of accounting standard in Partners' capital on its Consolidated Balance Sheet on January 1, 2018. All claims were dismissed in both the Hillsboro and Macoupin lawsuits.

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Environmental Compliance

The operations the Partnership's lessees conduct on its properties, as well as the aggregates/industrial minerals and oil and gas operations in which the Partnership has interests, are subject to federal and state environmental laws and regulations. See "Items 1. and 2. Business and Properties—Regulation and Environmental Matters." As an owner of surface interests in some properties, the Partnership may be liable for certain environmental conditions occurring on the surface properties. The terms of substantially all of the Partnership's coal leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. The Partnership makes regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. The Partnership believes that its lessees will be able to comply with existing regulations and does not expect that any lessee's failure to comply with environmental laws and regulations to have a material impact on the Partnership's financial condition or results of operations. The Partnership has neither incurred, nor is aware of, any material environmental charges imposed on the Partnership related to its properties for the period ended December 31, 2018. The Partnership is not associated with any material environmental contamination that may require remediation costs. However, the Partnership's lessees do conduct reclamation work on the properties under lease to them. Because the Partnership is not the permittee of the mines being reclaimed, the Partnership is not responsible for the costs associated with these reclamation operations.

As a former owner of the working interests in oil and natural gas operations, the Partnership is responsible for its proportionate share of any losses and liabilities, including environmental liabilities, arising from uninsured and underinsured events during the period it was an owner.

18. Unit-Based Compensation

2017 Long-Term Incentive Plan
In December 2017, the 2017 Long-Term Incentive Plan (the "2017 LTIP") was approved and it became effective in January 2018. The 2017 LTIP authorizes 800,000 common units that are available for delivery by the Partnership pursuant to awards under the plan. The term is 10 years from the date of Board approval or, if earlier, the date the 2017 LTIP is terminated by the Board or the committee appointed by the Board to administer the 2017 LTIP, or the date all available common units available have been delivered. Common units delivered pursuant to the 2017 LTIP will consist, in whole or part, of (i) common units acquired in the open market, (ii) common units acquired from the Partnership (including newly issued units), any of our affiliates or any other person or (iii) any combination of the foregoing.
Employees, consultants and non-employee directors of the Partnership, the General Partner, GP LLC and their affiliates are generally eligible to receive awards under the 2017 LTIP. The 2017 LTIP provides for the issuance of a variety of equity-based grants, including grants of (i) options, (ii) unit appreciation rights, (iii) restricted units, (iv) phantom units, (v) cash awards, (vi) performance awards, (vii) distribution equivalent rights, and (viii) other unit-based awards. The plan is administered by the Compensation, Nominating and Governance Committee of the Board, which determines the terms and conditions of awards granted under the 2017 LTIP. The Partnership recognizes forfeitures for any awards issued under this plan as they occur.
Unit-Based Awards

Unit-based awards under the 2017 LTIP are generally issued to certain employees and non-employee directors of the Partnership. Awards granted to employees vest at the end of a 3 year period and awards granted to non-employee directors are immediately vested. Directors are given the option to take immediate issuance of the vested awards or defer such issuance until a later date. Upon deferral of issuance, such units will continue to accumulate DERs until issuance.

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

A summary of activity in the outstanding grants during 2018 is as follows:

(In thousands)	Common Units	Weighted Average Exercise Price
Outstanding grants at January 1, 2018	—	—
Granted	75	29.16
Fully vested and issued	(17)	31.24
Forfeitures	(2)	38.28
Outstanding at December 31, 2018	56	29.10

The awards granted in the first quarter of 2018 were valued using the closing price of NRP's units as of the grant date. The grant date fair value of the 2017 LTIP awards granted during the period was $2.2 million, including awards granted to board members with a grant date fair value of $0.6 million which immediately vested and of which $0.4 million were issued. Total unit-based compensation expense recorded in the year ended December 31, 2018 associated with these awards was $1.0 million and $0.1 million included in General and administrative expense and Operating and maintenance expense, respectively, in the Partnership's Consolidated Statements of Comprehensive Income. The unamortized cost associated with unvested outstanding awards as of December 31, 2018 is $1.2 million, which is to be recognized over a weighted average period of 2.1 years.

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SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following table summarizes quarterly financial data for 2018:

(In thousands, except per unit data)	First Quarter (1) (2)	Second Quarter (1) (2)	Third Quarter (1)	Fourth Quarter (3) (4) (5)	Total 2018
Revenues (including affiliates)	$59,478	$69,451	$58,207	$63,935	$251,071
Gain on litigation settlement	—	—	—	25,000	25,000
Gain on asset sales, net	651	168	—	1,622	2,441
Asset impairments	242	—	—	18,038	18,280
Income from operations	44,236	52,863	43,346	52,093	192,538
Net income from continuing operations	26,286	35,129	25,853	35,092	122,360
Income (loss) from discontinued operations	(1,948)	2,981	2,688	13,966	17,687
Net income	24,338	38,110	28,541	49,058	140,047
Net income attributable to NRP	24,338	37,241	28,900	49,058	139,537
Net income attributable to common unitholders and general partner	16,838	29,741	21,400	41,558	109,537
Income from continuing operations per common unit					
Basic	$1.50	$2.14	$1.50	$2.21	$7.35
Diluted	1.16	1.57	1.18	1.69	5.90
Net income per common unit					
Basic	$1.35	$2.38	$1.71	$3.33	$8.77
Diluted	1.08	1.71	1.30	2.36	6.76
Weighted average number of common units outstanding (basic)	12,238	12,246	12,246	12,247	12,244
Weighted average number of common units outstanding (diluted)	22,125	21,383	21,840	20,394	20,234

(1) As a result of the sale of its construction aggregates business, the Partnership classified the operating results related to this business as discontinued operations in the Consolidated Statements of Comprehensive Income subsequent to the filing of the Third Quarter 2018 Form 10-Q. See below for a reconciliation to the amounts reported in the Third Quarter 2018 Form 10-Q.

(2) During the third quarter of 2018 the Partnership identified an error related to its modified retrospective adoption of ASC 606 on January 1, 2018 for certain coal and aggregates royalty leases and revised its financial statements for the first and second quarter of 2018 in its Third Quarter 2018 Form 10-Q.

(3) During the fourth quarter of 2018 the Partnership recorded $25 million in other income related to the Hillsboro litigation settlement. See Note 17. Commitments and Contingencies for more information.

(4) During the fourth quarter of 2018 the Partnership sold its construction aggregates business for $205 million, before customary purchase price adjustments and transaction expenses, and recorded a gain of $13.1 million included in Income from discontinued operations on the Partnership's Consolidated Statement of Comprehensive Income. See Note 4. Discontinued Operations for more information.

(5) During the fourth quarter of 2018 the Partnership recorded $18.0 million in aggregates and coal property impairment. See Note 11. Mineral Rights, Net for more information.

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SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

The following tables reconcile the previously reported quarterly information to the quarterly financial data disclosed above:

(In thousands, except per unit data)	As Originally Reported	Reclassified to Discontinued Operations	Revised
First Quarter 2018			
Revenues (including affiliates)	$86,630	$ (27,152)	$59,478
Gain on asset sales, net	660	(9)	651
Asset impairments	242	—	242
Income from operations	42,322	1,914	44,236
Net income from continuing operations	24,352	1,934	26,286
Net loss from discontinued operations	(14)	(1,934)	(1,948)
Net income	24,338	—	24,338
Net income attributable to NRP	24,338	—	24,338
Net income attributable to common unitholders and general partner	16,838	—	16,838
Income from continuing operations per common unit			
Basic	$1.35	$ 0.15	$1.50
Diluted	1.08	0.09	1.16
Net income per common unit			
Basic	$1.35	$ —	$1.35
Diluted	1.08	—	1.08
Weighted average number of common units outstanding (basic)	12,238	—	12,238
Weighted average number of common units outstanding (diluted)	22,125	—	22,125
Second Quarter 2018			
Revenues (including affiliates)	$109,860	$ (40,409)	$69,451
Gain on asset sales, net	210	(42)	168
Income from operations	55,878	(3,015)	52,863
Net income from continuing operations	38,144	(3,015)	35,129
Net income (loss) from discontinued operations	(34)	3,015	2,981
Net income	38,110	—	38,110
Net income attributable to NRP	37,241	—	37,241
Net income attributable to common unitholders and general partner	29,741	—	29,741
Income from continuing operations per common unit			
Basic	$2.38	$ (0.24)	$2.14
Diluted	1.71	(0.14)	1.57
Net income per common unit			
Basic	$2.38	$ —	$2.38
Diluted	1.71	—	1.71
Weighted average number of common units outstanding (basic)	12,246	—	12,246
Weighted average number of common units outstanding (diluted)	21,383	—	21,383

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

(In thousands, except per unit data)	As Originally Reported	Reclassified to Discontinued Operations	Revised
Third Quarter 2018			
Revenues (including affiliates)	$ 94,855	$ (36,648)	$ 58,207
Gain on asset sales, net	163	(163)	—
Income from operations	46,066	(2,720)	43,346
Net income from continuing operations	28,565	(2,712)	25,853
Net income (loss) from discontinued operations	(24)	2,712	2,688
Net income	28,541	—	28,541
Net income attributable to NRP	28,900	—	28,900
Net income attributable to common unitholders and general partner	21,400	—	21,400
Income from continuing operations per common unit			
Basic	$ 1.71	$ (0.22)	$ 1.50
Diluted	1.30	(0.12)	1.18
Net income per common unit			
Basic	$ 1.71	$ —	$ 1.71
Diluted	1.30	—	1.30
Weighted average number of common units outstanding (basic)	12,246	—	12,246
Weighted average number of common units outstanding (diluted)	21,840	—	21,840

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

The following table summarizes quarterly financial data for 2017:

(In thousands, except per unit data)	First Quarter (1) (2)	Second Quarter (1) (3)	Third Quarter (1)	Fourth Quarter (1)	Total 2017 (1)
Revenues (including affiliates)	$61,432	$58,015	$58,406	$64,927	$242,780
Gain on asset sales, net	29	3,184	154	178	3,545
Asset impairments	1,778	—	—	1,189	2,967
Income from operations	38,124	47,522	43,052	47,861	176,559
Debt modification expense	7,807	132	—	—	7,939
Loss on extinguishment of debt	—	4,107	—	—	4,107
Net income from continuing operations	7,588	23,153	23,079	28,665	82,485
Net income (loss) from discontinued operations	(1,684)	2,837	2,987	2,042	6,182
Net income	5,904	25,990	26,066	30,707	88,667
Net income attributable to common unitholders and general partner	3,404	18,452	18,416	22,942	63,214
Income from continuing operations per common unit					
Basic	$0.41	$1.25	$1.24	$1.67	$4.57
Diluted	0.50	1.01	0.94	1.18	3.68
Net income per common unit					
Basic	$0.28	$1.47	$1.48	$1.84	$5.06
Diluted	0.28	1.13	1.07	1.26	3.96
Weighted average number of common units outstanding (basic)	12,232	12,232	12,232	12,232	12,232
Weighted average number of common units outstanding (diluted)	14,945	22,459	23,980	23,874	21,950

(1) As a result of the sale of its construction aggregates business, the Partnership classified the operating results related to this business as discontinued operations in the Consolidated Statements of Comprehensive Income subsequent to the filing of the 2017 Form 10-K. See below for a reconciliation to the amounts reported in the 2017 Form 10-K.

(2) During the first quarter of 2017 the Partnership incurred $7.8 million of debt modification costs as a result of the exchange of $241 million of our 2018 Senior Notes for 2022 Senior Notes.

(3) During the second quarter of 2017 the Partnership incurred a $4.1 million loss on extinguishment of debt related to the 4.563% premium paid to redeem the 2018 Senior Notes in April 2017.

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

The following tables reconcile the previously reported quarterly information to the quarterly financial data disclosed above:

(In thousands, except per unit data)	As Originally Reported	Reclassified to Discontinued Operations	Revised
First Quarter 2017			
Revenues (including affiliates)	$ 88,653	$ (27,221)	$ 61,432
Gain on asset sales, net	44	(15)	29
Asset impairments	1,778	—	1,778
Income from operations	37,042	1,082	38,124
Debt modification expense	7,807	—	7,807
Net income from continuing operations	6,111	1,477	7,588
Net income (loss) from discontinued operations	(207)	(1,477)	(1,684)
Net income	5,904	—	5,904
Net income attributable to common unitholders and general partner	3,404	—	3,404
Income from continuing operations per common unit			
Basic	$ 0.30	$ 0.12	$ 0.41
Diluted	0.30	0.10	0.50
Net income per common unit			
Basic	$ 0.28	$ —	$ 0.28
Diluted	0.28	—	0.28
Weighted average number of common units outstanding (basic)	12,232	—	12,232
Weighted average number of common units outstanding (diluted)	14,945	—	14,945
Second Quarter 2017			
Revenues (including affiliates)	$ 91,570	$ (33,555)	$ 58,015
Gain on asset sales, net	3,361	(177)	3,184
Income from operations	50,404	(2,882)	47,522
Debt modification expense	132	—	132
Loss on extinguishment of debt	4,107	—	4,107
Net income from continuing operations	25,857	(2,704)	23,153
Net income (loss) from discontinued operations	133	2,704	2,837
Net income	25,990	—	25,990
Net income attributable to common unitholders and general partner	18,452	—	18,452
Income from continuing operations per common unit			
Basic	$ 1.46	$ (0.22)	$ 1.25
Diluted	1.13	(0.12)	1.01
Net income per common unit			
Basic	$ 1.47	$ —	$ 1.47
Diluted	1.13	—	1.13
Weighted average number of common units outstanding (basic)	12,232	—	12,232
Weighted average number of common units outstanding (diluted)	22,459	—	22,459

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

(In thousands, except per unit data)	As Originally Reported	Reclassified to Discontinued Operations	Revised
Third Quarter 2017			
Revenues (including affiliates)	$93,116	$ (34,710)	$58,406
Gain on asset sales, net	171	(17)	154
Income from operations	46,531	(3,479)	43,052
Net income from continuing operations	26,499	(3,420)	23,079
Net income (loss) from discontinued operations	(433)	3,420	2,987
Net income	26,066	—	26,066
Net income attributable to common unitholders and general partner	18,416	—	18,416
Income from continuing operations per common unit			
Basic	$1.51	$ (0.27)	$1.24
Diluted	1.08	(0.14)	0.94
Net income per common unit			
Basic	$1.48	$ —	$1.48
Diluted	1.07	—	1.07
Weighted average number of common units outstanding (basic)	12,232	—	12,232
Weighted average number of common units outstanding (diluted)	23,980	—	23,980
Fourth Quarter 2017			
Revenues (including affiliates)	$100,822	$ (35,895)	$64,927
Gain on asset sales, net	280	(102)	178
Asset impairments	1,253	(64)	1,189
Income from operations	49,998	(2,137)	47,861
Net income from continuing operations	30,741	(2,076)	28,665
Net income (loss) from discontinued operations	(34)	2,076	2,042
Net income	30,707	—	30,707
Net income attributable to common unitholders and general partner	22,942	—	22,942
Income from continuing operations per common unit			
Basic	$1.84	$ (0.17)	$1.67
Diluted	1.26	(0.09)	1.18
Net income per common unit			
Basic	$1.84	$ —	$1.84
Diluted	1.26	—	1.26
Weighted average number of common units outstanding (basic)	12,232	—	12,232
Weighted average number of common units outstanding (diluted)	23,874	—	23,874

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

(In thousands, except per unit data)	As Originally Reported	Reclassified to Discontinued Operations	Revised
Total 2017			
Revenues (including affiliates)	$374,161	$(131,381)	$242,780
Gain on asset sales, net	3,856	(311)	3,545
Asset impairments	3,031	(64)	2,967
Income from operations	183,975	(7,416)	176,559
Debt modification expense	7,939	—	7,939
Loss on extinguishment of debt	4,107	—	4,107
Net income from continuing operations	89,208	(6,723)	82,485
Net income (loss) from discontinued operations	(541)	6,723	6,182
Net income	88,667	—	88,667
Net income attributable to common unitholders and general partner	63,214	—	63,214
Income from continuing operations per common unit		—	
Basic	$5.11	$(0.54)	$4.57
Diluted	3.98	(0.30)	3.68
Net income per common unit			
Basic	$5.06	$—	$5.06
Diluted	3.96	—	3.96
Weighted average number of common units outstanding (basic)	12,232	—	12,232
Weighted average number of common units outstanding (diluted)	21,950	—	21,950

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2018. This evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures were effective as of December 31, 2018 at the reasonable assurance level in producing the timely recording, processing, summary and reporting of information and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosures.

Management’s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2018 based on the framework in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission "2013 Framework" (COSO). Based on that evaluation, as of December 31, 2018, our management concluded that our internal control over financial reporting was effective at a reasonable assurance level based on those criteria. No changes were made to our internal control over financial reporting during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

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Report of Independent Registered Public Accounting Firm

The Partners of Natural Resource Partners L.P.

Opinion on Internal Control over Financial Reporting

We have audited Natural Resource Partners L.P.'s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Natural Resource Partners L.P. (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2018 and 2017, the related consolidated statements of comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and our report dated March 7, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Ernst & Young LLP
Houston, Texas
March 7, 2019

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ITEM 9B. OTHER INFORMATION

None.

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PART III

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

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

Name	Age	Position with the General Partner
Corbin J. Robertson, Jr.	71	Chairman of the Board and Chief Executive Officer
Craig W. Nunez	57	President and Chief Operating Officer
Christopher J. Zolas	44	Chief Financial Officer and Treasurer
Jennifer L. Odinet	40	Chief Accounting Officer
Kevin J. Craig	50	Executive Vice President, Coal
Kathryn S. Wilson	44	Vice President, General Counsel and Secretary
Gregory F. Wooten	63	Vice President, Chief Engineer
Galdino J. Claro	59	Director
Russell D. Gordy	68	Director
Jasvinder S. Khaira	37	Director
S. Reed Morian	73	Director
Paul B. Murphy, Jr.	59	Director
Richard A. Navarre	58	Director
Corbin J. Robertson, III	48	Director
Stephen P. Smith	58	Director
Leo A. Vecellio, Jr.	72	Director

Corbin J. Robertson, Jr. has served as Chief Executive Officer and Chairman of the Board of Directors of GP Natural Resource Partners LLC since 2002. Mr. Robertson has vast business experience having founded and served as a director and as an officer of multiple companies, both private and public, and has served on the boards of numerous non-profit organizations. He has served as the Chief Executive Officer and Chairman of the Board of the general partner of Great Northern Properties Limited Partnership since 1992 and Quintana Minerals Corporation since 1978, as Chairman of the Board of Directors of New Gauley Coal Corporation since 1986, and the general partner of Western Pocahontas Properties Limited Partnership since 1986. In addition, Mr. Robertson served as Chief Executive Officer of the general partner of Western Pocahontas Properties Limited Partnership from 1986 until 2008 and currently serves on the Board of Managers of Premium Resources, LLC. He also serves as a Principal with Quintana Capital Group, Chairman of the Board of the Cullen Trust for Higher Education and on the boards of the American Petroleum Institute, the National Petroleum Council, the Baylor College of Medicine and the Spirit Golf Association. In 2006, Mr. Robertson was inducted into the Texas Business Hall of Fame. Mr. Robertson is the father of Corbin J. Robertson, III.

Craig W. Nunez has served as President and Chief Operating Officer of GP Natural Resource Partners LLC since August 2017 and previously served as Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC from January 2015 to August 2017. Prior to joining NRP, Mr. Nunez was an owner and Chief Executive Officer of Bocage Group, a private investment company specializing in energy, natural resources and master limited partnerships since March 2012. In addition, until joining NRP, he was a FINRA-registered Investment Advisor Representative with Searle & Co since July 2012 and served as an Executive Advisor to Capital One Asset Management since January 2014. From September 2011 through March 2012, Mr. Nunez served as the Executive Vice President and Chief Financial Officer of Quicksilver Resources Canada, Inc. Mr. Nunez was Senior Vice President and Treasurer of Halliburton Company from January 2007 until September 2011, and Vice President and Treasurer of Halliburton Company from February 2006 to January 2007. Prior to that, he was Treasurer of Colonial Pipeline Company from November 1995 to February 2006. Mr. Nunez has been involved in numerous charitable organizations and currently serves on the boards of Goodwill Industries of Houston and Medical Bridges, Inc.

Christopher J. Zolas has served as Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC since August 2017 and previously served as Chief Accounting Officer of GP Natural Resource Partners from March 2015 to August 2017. Prior to joining NRP, Mr. Zolas served as Director of Financial Reporting at Cheniere Energy, Inc., a publicly traded energy company, where he performed financial statement preparation and analysis, technical accounting and SEC reporting for five separate SEC registrants, including a master limited partnership. Mr. Zolas joined Cheniere Energy, Inc. in 2007 as Manager of SEC Reporting and Technical Accounting and was promoted to Director in 2009. Prior to joining Cheniere Energy, Inc., Mr. Zolas worked in public accounting with KPMG LLP from 2002 to 2007.

Jennifer L. Odinet joined GP Natural Resource Partners LLC as Chief Accounting Officer in October 2017. Ms. Odinet most recently served as Director, Financial Reporting for Cabot Oil & Gas Corporation, a publicly traded energy company, where she was responsible for SEC and internal reporting, complex technical accounting matters and financial statement preparation and analysis. Prior to joining Cabot, Ms. Odinet was a Senior Manager in the Assurance practice for PricewaterhouseCoopers LLC from June 2000 to April 2010.

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

Kathryn S. Wilson has served as Vice President, General Counsel and Secretary of GP Natural Resource Partners LLC since December 2013. Ms. Wilson served as Associate General Counsel from March 2013 to December 2013. Since October 2013, Ms. Wilson has also served as General Counsel and Secretary of each of New Gauley Coal Corporation, the general partner of Western Pocahontas Properties Limited Partnership, and the general partner of

Great Northern Properties Limited Partnership. She served as General Counsel of Quintana Minerals Corporation from December 2013 to November 2018. Ms. Wilson practiced corporate and securities law with Vinson & Elkins L.L.P. from September 2001 to February 2010 and from November 2011 to February 2013. Ms. Wilson served as General Counsel of Antero Resources Corporation from March 2010 to June 2011.

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

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Galdino J. Claro joined the Board of Directors of GP Natural Resource Partners LLC in March 2018. Mr. Claro has 30 years of worldwide executive leadership experience in the primary and secondary metals industries. From October 2013 to August 2017, Mr. Claro served as the Group Chief Executive Officer and Managing Director of Sims Metal Management where he was also a member of the Safety, Health, Environment and Sustainability Committee, the Nomination Governance Committee and the Finance Investment Committee. Before joining Sims Metal Management, Mr. Claro served for four years as the Chief Executive Officer of Harsco Metals and Minerals. He joined Harsco from Aleris, where he served as CEO of Aleris Americas. Before that, he was the CEO of the Metals Processing Group of Heico Companies LLC. During his career with Alcoa Inc., Mr. Claro served for five years as the President of Alcoa China and for six years in Europe as the Vice President of Soft Alloys Extrusions and the President of Alcoa Europe Extrusions. While in South America, Mr. Claro worked for several different divisions of Alcoa Alumni SA as plant manager, technology manager, new products development director and Managing Director of Alcoa Cargo-Van. Before joining Alcoa in 1985, Mr. Claro started his career at Honda-Motogear as a Quality Control Manager where he worked for three years in both Brazil and Japan.

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

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

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

Paul B. Murphy, Jr. joined the Board of Directors of GP Natural Resource Partners LLC in March 2018. Mr. Murphy is the Chairman and Chief Executive Officer and a Director of Cadence Bancorporation and Chairman of Cadence

Bank, N.A. He has served at Cadence and its predecessors since December 2009. Cadence is a $17 billion bank holding company headquartered in Houston and it is traded on the NYSE (CADE). Previously, Mr. Murphy spent 20 years at Amegy Bank of Texas, helping to steer that institution from $75 million in assets and a single location to assets of $11 billion and 85 banking centers at the time of his departure as the Chief Executive Officer and a Director in 2009. Mr. Murphy is an advocate of the community and is a board member of Oceaneering International, Inc. and the Houston Hispanic Chamber of Commerce. He is active in the World Presidents Organization.

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

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

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

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

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Corporate Governance

Board Meetings and Executive Sessions

The Board met 10 times in 2018. During 2018, our non-management directors met in executive session several times. The presiding director was Mr. Vecellio, the Chairman of our Compensation, Nominating and Governance Committee, or CNG Committee. In addition, our independent directors met one time in executive session in December 2018. Mr. Vecellio was the presiding director at that meeting. Interested parties may communicate with our non-management directors by writing a letter to the Chairman of the CNG Committee, NRP Board of Directors, 1201 Louisiana Street, Suite 3400, Houston, Texas 77002.

Independence of Directors

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

Audit Committee

Our Audit Committee is currently comprised of Mr. Smith, who serves as chairman, Mr. Claro and Mr. Navarre. Mr. Smith, Mr. Claro, and Mr. Navarre are "Audit Committee Financial Experts" as determined pursuant to Item 407 of Regulation S-K. During 2018, the Audit Committee met seven times. Mr. Claro joined the Audit Committee effective March 2, 2018. Mr. Gordy served as a member of the Audit Committee from January 1, 2018 through March 1, 2018.

Report of the Audit Committee

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

During 2018, at each of its meetings, the Audit Committee met with the senior members of our financial management team, our general counsel and our independent auditors. The Audit Committee had private sessions at certain of its meetings with our independent auditors and the senior members of our financial management team and the general counsel at which candid discussions of financial management, accounting and internal control and legal issues took place.

The Audit Committee approved the engagement of Ernst & Young LLP as our independent auditors for the year ended December 31, 2018 and reviewed with our financial managers and the independent auditors overall audit scopes and plans, the results of internal and external audit examinations, evaluations by the auditors of our internal controls and the quality of our financial reporting.

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

The Committee also discussed with the independent auditors other matters required to be discussed by the auditors with the Committee by PCAOB Auditing Standard No. 16, Communications With Audit Committees. The Committee received and discussed with the auditors their annual written report on their independence from the partnership and its management, which is made under Rule 3526, Communication With Audit Committees Concerning Independence, and considered with the auditors whether the provision of non-audit services provided by them to the partnership during 2018 was compatible with the auditors' independence.

In performing all of these functions, the Audit Committee acts only in an oversight capacity. The Audit Committee reviews our Quarterly Reports on Form 10-Q and Annual Reports on Form 10-K prior to filing with the Securities and Exchange Commission. In 2018, the Audit Committee also reviewed quarterly earnings announcements with management and representatives of the independent auditor in advance of their issuance. In its oversight role, the Audit Committee relies on the work and assurances of our management, which has the primary responsibility for financial statements and reports, and of the independent auditors, who, in their report, express an opinion on the conformity of our annual financial statements with U.S. generally accepted accounting principles.

In reliance on these reviews and discussions, and the report of the independent auditors, the Audit Committee has recommended to the Board of Directors, and the Board has approved, that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2018, for filing with the Securities and Exchange Commission.

Stephen P. Smith, Chairman
Galdino J. Claro
Richard A. Navarre

Compensation, Nominating and Governance Committee

Executive officer compensation is administered by the CNG Committee, which is currently comprised of three members: Mr. Vecellio, as Chairman, Mr. Gordy and Mr. Smith. The CNG Committee has reviewed and approved the compensation arrangements described in the Compensation Discussion and Analysis section of this Annual Report on Form 10-K. During 2018, the CNG Committee met two times. Our Board of Directors appoints the CNG Committee and delegates to the CNG Committee responsibility for:

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

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

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of their equity securities. These people are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required for transactions occurring in 2017, and we believe that, except as provided below, our officers and directors and persons who beneficially own more than ten percent of a registered class of our equity securities complied with all filing requirements with respect to transactions in our equity securities during 2018. On June 11, 2018, Mr. Murphy filed a Form 4 reporting purchase of 3,159 common units on June 5, 2018 and 3,659 common units on June 6, 2018 that had not been previously reported on a timely basis.

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Partnership Agreement

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

Corporate Governance Guidelines and Code of Business Conduct and Ethics

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

NYSE Certification

Pursuant to Section 303A of the NYSE Listed Company Manual, in 2018, Corbin J. Robertson, Jr. certified to the NYSE that he was not aware of any violation by the Partnership of NYSE corporate governance listing standards.

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ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Overview

As a publicly traded partnership, we have a unique employment and compensation structure that is different from that of a typical public corporation. Our executive officers based in Houston, Texas are employed by Quintana Minerals Corporation (“Quintana”), and our executive officers based in Huntington, West Virginia are employed by Western Pocahontas Properties Limited Partnership (“Western Pocahontas”). Quintana and Western Pocahontas are controlled by our Chairman and Chief Executive Officer and are affiliates of NRP. While our executive officers are employed by affiliates of NRP, each of them has been appointed to serve as an executive officer of GP Natural Resource Partners LLC (“GP LLC”), the general partner of NRP (GP) LLC (“NRP GP”), the general partner of NRP. For a more detailed description of our structure, see "Items 1. and 2. Business and Properties—Partnership Structure and Management" in this Annual Report on Form 10-K.

Although our executives’ salaries and bonuses are paid directly by the private companies that employ them, we reimburse those companies based on the time allocated to NRP by each executive officer. Our reimbursement for the compensation of executive officers is governed by our partnership agreement. For purposes of this Compensation Discussion and Analysis, our “named executive officers” are:

- Corbin J. Robertson, Jr.—Chairman and Chief Executive Officer
- Craig W. Nunez—President and Chief Operating Officer
- Christopher J. Zolas—Chief Financial Officer and Treasurer
- Kathryn S. Wilson—Vice President, General Counsel and Secretary
- Jennifer L. Odinet—Chief Accounting Officer
- Perry W. Donahoo—Former Chief Executive Officer—VantaCore

Executive Officer Compensation Strategy and Philosophy

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Historically, our primary business objective was to generate cash flows at levels that could sustain long-term quarterly cash distributions to our investors. However, given the difficult coal markets over the past few years, coupled with the limitations on our ability to access capital from additional sources, our current objective is to preserve long-term equity value for our unitholders by using our excess free cash flow to reduce our leverage. Our objective in determining the compensation of our executive officers is to retain qualified people to manage the business under current market conditions. Incentive compensation for the year ended December 31, 2018 was discretionary but certain performance criteria were considered as factors, as further described under “—Components of Compensation.”

The 2018 compensation for executive officers consisted of four primary components:

- base salaries;
- short-term cash incentive compensation;
- long-term cash incentive compensation; and
- perquisites and other benefits.

All our named executive officers, other than Corbin J. Robertson, Jr., our Chairman and Chief Executive Officer, spent 100% of their time on NRP matters during 2018, and NRP bears the proportionate cost of their time. Mr. Robertson does not receive a salary in his capacity as Chief Executive Officer. Mr. Robertson is compensated through short-term cash and long-term equity incentive awards.

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Historically, in February of each year, the CNG Committee has approved the short-term cash incentive award for the year just ended and long-term incentive awards for the executive officers. The CNG Committee considers the performance of the partnership, the performance of the individuals and the outlook for the future in determining the amounts of the awards. Prior to 2016, we issued phantom units, coupled with tandem distribution equivalent rights ("DERs"), to our executive officers that were paid in cash based on the average closing price of our common units for the 20-day trading period prior to vesting. The phantom units and DERs typically vested four years from the date of grant, with the last grants of these awards vested in February 2019. We refer to these phantom units as "Cash Settled Phantom Units."

In December 2017, the CNG Committee approved and the Board adopted the Natural Resource Partners 2017 Long-Term Incentive Plan (the "2017 Plan"), subject to unitholder approval. On December 20, 2017, unitholders holding the requisite percentage of votes necessary to approve the 2017 Plan approved the 2017 Plan by written consent in lieu of a special meeting of unitholders. The 2017 Plan became effective on January 16, 2018. Beginning in February 2018, the CNG Committee has made awards of phantom units to be settled in common units under the 2017 Plan to NRP's officers in order to incentivize management while also aligning the long-term interests of management with the interests of NRP's unitholders.

Role of Compensation Experts

Neither the Board nor the CNG Committee retained any consultants to evaluate compensation of officers or directors in 2018.

Role of Our Executive Officers in the Compensation Process

With respect to 2018 salaries and short-term cash incentive awards and long-term equity incentive awards, Mr. Nunez, our President and Chief Operating Officer, provided Mr. Robertson with recommendations relating to the executive officers other than himself. Mr. Robertson considered those recommendations and provided the CNG Committee with recommendations for all of the executive officers other than himself. Messrs. Robertson and Nunez considered the factors described elsewhere in this compensation discussion and analysis in recommending, in their discretion, the appropriate amounts for each named executive officer. Messrs. Robertson and Nunez attended the CNG Committee meetings at which the Committee deliberated and approved 2018 salaries, short-term cash incentive awards and long-term equity incentive awards but were excused from the meetings when the CNG Committee discussed their compensation.

Components of Compensation

Base Salaries

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

In determining salaries for NRP's executive officers for 2018, at the December 2017 meeting, the CNG Committee considered the financial performance of NRP for the nine months ended September 30, 2017 as well as the projected financial performance of NRP for the fourth quarter of 2017 and for the year ending December 31, 2018. The CNG Committee also considered the individual performance of each member of the executive management team during 2017. Salaries for 2018 are shown in the Summary Compensation Table below.

Short-Term Cash Incentive Compensation

Each named executive officer received a discretionary short-term cash incentive award approved in February 2019 by the CNG Committee. The amounts awarded with respect to 2018 under this program are disclosed in the Summary Compensation Table under the Bonus column. With respect to 2018, the CNG Committee provided general guidelines that cash bonuses would be paid based on a range of 60% to 140% of base salary, with Mr. Robertson receiving two times the amount awarded to the President and Chief Operating Officer. In addition, the CNG Committee determined that it would consider certain criteria to determine bonus amounts within this range, but that the criteria utilized at the time of determination, as well as the relative weight of those criteria, would be generally discretionary and subject to change based on developments at the company.

Long-Term Equity Incentive Compensation

Each named executive officer received a discretionary long-term equity incentive award in 2018 under the 2017 Plan. The 2018 awards were made in the form of phantom units that will settle in NRP common units on a one-for-one basis following vesting in February 2021 and will accrue DERs to be paid in cash upon settlement. We refer to these phantom units issued in 2018 as “2017 Plan Phantom Units.” The 2017 Plan Phantom Units are subject to forfeiture and will vest on an accelerated basis following death or disability of the award recipient or following a change in control of NRP. The grant date fair value of the 2017 Plan Phantom Units awarded in 2018 are disclosed in the Summary Compensation Table under the Stock Awards column. For the 2017 Plan Phantom Units awarded in 2018, the CNG Committee generally awarded an amount equal to 60% of base salary, with Mr. Robertson receiving two times the amount awarded to the President and Chief Operating Officer. The CNG Committee considered performance of the company and individual performance in making these awards, as well as the cash incentive awards received by certain of the named executive officers in March 2017.

Perquisites and Other Personal Benefits

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

In 2018, Quintana and Western Pocahontas maintained tax-qualified 401(k) and defined contribution retirement plans. During 2018, Quintana and Western Pocahontas matched 100% of the first 6.0% of the employee contributions under their respective 401(k) plans. As with the other contributions, any amounts contributed by Quintana and Western Pocahontas are reimbursed by us based on the time allocated by the employee to our business. None of NRP, Quintana or Western Pocahontas maintains a pension plan or a defined benefit retirement plan.

Unit Ownership Requirements

NRP maintains Unit Ownership and Retention Guidelines (the “ownership guidelines”) that are administered by the CNG Committee and require NRP’s officers who are required to file ownership reports under Section 16 of the Securities Exchange Act of 1934 (the “Exchange Act”) and certain other officers as designated from time-to-time by the Board or the CNG Committee to retain all common units awarded under any NRP incentive plan (net of any units withheld or sold to cover tax liabilities) until certain ownership guidelines are met. The guideline for NRP’s President and Chief Operating Officer is for such individual to hold common units having a value of four times his or her base salary at the date of measurement. The guideline for NRP's Chief Financial Officer is for such individual to hold common units having a value of two times his or her base salary at the date of measurement. The guideline for NRP's Vice President & General Counsel and Chief Accounting Officer is for such individuals to hold common units having a value of one and one-half times his or her base salary at the date of measurement. There is no minimum time period required to achieve the unit ownership guidelines. Due to his substantial ownership in us, the ownership guidelines do not currently apply to our Chief Executive Officer.

The ownership guidelines also require directors who are not officers to retain common units with a value equal to three times the amount of the annual cash retainer paid to directors. Directors are required to achieve the unit ownership guideline within five years. Until the unit ownership guideline is achieved, each director is encouraged to retain all common units awarded under any NRP incentive plan (net of any units sold to cover tax liabilities).

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Units that count towards the satisfaction of the officer and director guidelines include common units held directly by the executive officer or director, common units owned indirectly by the executive officer or director (e.g., by a spouse or other immediate family member residing in the same household or a trust for the benefit of the executive officer or director or his or her family), units granted under NRP's long-term incentive plans (including phantom units representing the right to receive units), and units purchased in the open market (whether purchased before or after the effective date of the ownership guidelines).

Incentive Compensation Recoupment Policy

NRP maintains the Natural Resource Partners L.P. Incentive Compensation Recoupment Policy, which is administered by the CNG Committee. The policy authorizes the Board or committee thereof to recoup incentive compensation in the event of a restatement of financial statements due to material non-compliance with securities laws, fraud or misconduct.

Securities Trading Policy

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

Report of the Compensation, Nominating and Governance Committee

The CNG Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management. Based on the reviews and discussions referred to in the foregoing sentence, the CNG Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the year ended December 31, 2018.

Leo A. Vecellio, Jr., Chairman
Russell D. Gordy
Stephen P. Smith

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Summary Compensation Table

The following table sets forth the amounts reimbursed to affiliates of our general partner for compensation for 2016, 2017 and 2018:

Name and Principal Position	Year	Salary ($)	Bonus ($)	Non-Equity Incentive Plan Compensation ($)	Stock Awards ($) [1]	All Other Compensation ($) [2]	Total ($)
Corbin J. Robertson, Jr.—Chief Executive Officer							
	2018	—	1,208,247	—	418,836	—	1,627,083
	2017	—	—	3,250,000	—	—	3,250,000
	2016	—	—	—	—	—	—
Craig W. Nunez—President and Chief Operating Officer							
	2018	447,499	604,124	—	209,433	16,800	1,277,856
	2017	375,000	250,000	1,218,750	—	34,650	1,878,400
	2016	375,000	425,000	—	—	34,383	834,383
Christopher J. Zolas—Chief Financial Officer							
	2018	337,499	455,624	—	167,529	16,800	977,452
	2017	300,000	180,000	375,000	—	34,650	889,650
	2016	300,000	200,000	—	—	34,383	534,383
Kathryn S. Wilson—Vice President, General Counsel and Secretary [3]							
	2018	347,499	469,124	—	139,622	16,800	973,045
	2017	321,750	150,000	975,000	—	34,304	1,481,054
	2016	305,500	225,000	—	—	31,631	562,131
Jennifer L. Odinet—Chief Accounting Officer [4]							
	2018	287,082	387,561	—	148,003	16,800	839,446
Perry W. Donahoo—Former Chief Executive Officer—VantaCore [5]							
	2018	314,767	314,767	—	170,322	2,367,756	3,167,612

(1) Amounts represent the grant date fair value of phantom unit awards determined in accordance with Accounting Standards Codification Topic 718 determined without regard to forfeitures. For information regarding the assumptions used in calculating these amounts, see "Item 8. Financial Statements and Supplementary Data—Note 18. Unit-Based Compensation" elsewhere in this Annual Report on Form 10-K for more information.

(2) Includes portions of 401(k) matching allocated to Natural Resource Partners by Quintana and Western Pocahontas.

(3) Ms. Wilson allocated approximately 94%, 99% and 100% of her time to NRP during the years ended December 31, 2016, 2017 and 2018, respectively, and amounts included in the table reflect this allocation.

(4) Ms. Odinet was not a named executive officer for purposes of this table during the years ended December 31, 2016 or 2017.

(5) Mr. Donahoo was not a named executive officer for purposes of this table during the years ended December 31, 2016 or 2017 and resigned as Chief Executive Officer—VantaCore effective December 11, 2018 in connection with

our sale of that business. Upon his resignation, and in accordance with his employment agreement with Quintana, Mr. Donahoo received a severance payment of $500,399, which will be paid out in equal monthly installments during 2019. This severance, as well as a transaction bonus paid to Mr. Donahoo in connection with the VantaCore sale, are disclosed under the All Other Compensation column. See “—Employment Agreements.”

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Grants of Plan-Based Awards in 2018

The following table shows the 2017 Plan Phantom Units granted to named executive officers during 2018. The awards in the table below will vest in February 2021, and upon settlement, an equivalent number of common units will be issued to each named executive officer, subject to withholding. The 2017 Plan Phantom Units also accrue DERs from the grant date, which will be paid out in cash upon settlement following and subject to vesting.

Named Executive Officer	2017 Plan Phantom Units Grant Date	Number of Units	Grant Date Fair Value
Corbin J. Robertson, Jr.	2/14/2018	14,393	$418,836
Craig W. Nunez	2/14/2018	7,197	209,433
Christopher J. Zolas	2/14/2018	5,757	167,529
Kathryn S. Wilson	2/14/2018	4,798	139,622
Jennifer L. Odinet	2/14/2018	5,086	148,003
Perry W. Donahoo[(1)]	2/14/2018	5,853	170,322

(1) Mr. Donahoo's phantom units vested in full on December 11, 2018, the date of the sale of VantaCore. His phantom units were net settled for tax purposes, resulting in the issuance by us of 3,549 common units and a cash payment of the associated accrued DERs.

Employment Agreements

We sold our construction aggregates business, VantaCore, on December 11, 2018. Mr. Donahoo served as Chief Executive Officer of VantaCore and was employed by Quintana. Pursuant to his employment agreement with Quintana, Mr. Donahoo was entitled to certain benefits upon NRP's sale of the VantaCore business. Accordingly, in December 2018, Mr. Donahoo received a bonus amount equal to 100% of his 2018 base salary prorated through the sale date. In addition, the vesting of all of Mr. Donahoo's Cash Settled Phantom Units and 2017 Plan Phantom Units was accelerated to the closing date, and Mr. Donahoo received cash and common units accordingly. Finally, pursuant to his employment agreement, Mr. Donahoo is entitled to receive an amount equal to 18 months of his 2018 base salary, or $500,399, to be paid in equal installments each month during 2019.

None of our other named executive officers has an employment agreement.

Phantom Units Vested in 2018

The table below shows the Cash Settled Phantom Units and 2017 Plan Phantom Units that vested in 2018 with respect to each named executive officer, along with value realized by each individual:

Named Executive Officer	Equity Awards During 2018 Cash Settled Phantom Units	2017 Plan Phantom Units	Value Realized on Vesting[(1)]
Corbin J. Robertson, Jr.	3,360	—	$ 174,678
Craig W. Nunez	1,300	—	53,934
Christopher J. Zolas	800	—	30,390
Kathryn S. Wilson	683	—	35,507
Jennifer L. Odinet	—	—	—
Perry W. Donahoo	1,743[(2)]	5,853[(3)]	314,369

(1) Includes DERs accrued from the issue date to the settlement date.

(2) Includes 850 phantom units that vested February 2018 and 893 phantom units vested in December 2018 in connection with the VantaCore sale, each of which settled in cash based on the average closing price of NRP's common units for the 20 trading days prior to the vesting date.

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(3) 2017 Plan Phantom Units vested in full in December 2018 in connection with the VantaCore sale at a price of $38.28, the closing price of NRP's common units on the closing date of the sale.

Outstanding Equity Awards at December 31, 2018

The table below shows the total number of outstanding Cash Settled Phantom Units and 2017 Plan Phantom Units held by each named executive officer at December 31, 2018.

Named Executive Officer	Unvested Cash Settled Phantom Units(1)	Market Value of Unvested Cash Settled Phantom Units (2)	Unvested 2017 Plan Phantom Units(3)	Market Value of Unvested 2017 Plan Phantom Units(2)
Corbin J. Robertson, Jr.	3,600	$ 137,664	14,393	$ 550,388
Craig W. Nunez	1,400	53,536	7,197	275,213
Christopher J. Zolas	950	36,328	5,757	220,148
Kathryn S. Wilson	950	36,328	4,798	183,476
Jennifer L. Odinet	—	—	5,086	194,489
Perry W. Donahoo	—	—	—	—

(1) Cash Settled Phantom Units were awarded in February 2015 and vested in February 2019.
(2) Based on a unit price of $38.24, the closing price for the common units on December 31, 2018.
(3) 2017 Plan Phantom Units were awarded in February 2018 and vest in February 2021.

Potential Payments upon Termination or Change in Control

Upon the occurrence of a change in control of NRP, our general partner, or GP Natural Resource Partners LLC, any outstanding Cash Settled Phantom Units and 2017 Plan Phantom Units held by each of our named executive officers would immediately vest and become payable. The table below indicates the estimated payments to each named executive officer following a change in control at December 31, 2018.

	Cash Settled Phantom Units			2017 Plan Equity Awards			
Named Executive Officer	Unvested Phantom Units	Market Value(1)	Accumulated DERs	Unvested Phantom Units	Market Value(2)	Accumulated DERs	Total Potential Payments
Corbin J. Robertson, Jr.	3,600	$ 135,580	27,540	14,393	$ 550,388	19,431	$ 732,938
Craig W. Nunez	1,400	52,725	10,710	7,197	275,213	9,716	348,365
Christopher J. Zolas	950	35,778	7,268	5,757	220,148	7,772	270,965
Kathryn S. Wilson	950	35,778	7,268	4,798	183,476	6,477	232,998
Jennifer L. Odinet	—	—	—	5,086	194,489	6,866	201,355
Perry W. Donahoo(3)	893	33,631	6,831	5,853	223,819	7,902	272,183

(1) Calculated based on a per unit price of $37.661, the average closing price for our common units for the 20 trading days ended December 31, 2018, as required by the terms of the phantom unit agreements.
(2) Calculated based on a unit price of $38.24, the closing price for the common units on December 31, 2018.
(3) Amounts represent what Mr. Donahoo would have received if he had been an officer at December 31, 2018. Amounts actually received by Mr. Donahoo are shown in the table under "—Phantom Units Vested in 2018." In accordance with his employment agreement with Quintana, if a change in control of NRP had occurred on December 31, 2018, Mr. Donahoo was also entitled to receive cash payment of $500,399 payable over the following 12 months, a cash bonus of $314,767, and reimbursement of COBRA premiums up to $40,616.

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Directors' Compensation for the Year Ended December 31, 2018

During the year ended December 31, 2018, there were a number of changes to the Board and the committees thereof:

- Effective January 1, 2018 through March 1, 2018, Mr. Russell D. Gordy served on the Audit Committee.
- Effective March 2, 2018, Mr. Paul B. Murphy, Jr. joined the Board; and
- Effective March 2, 2018, Mr. Galdino J. Claro joined the Board and the Audit Committee and the Conflicts Committee;

For more information regarding the Board and committees thereof, see "Item 10. Directors and Executive Officers of the Managing General Partner and Corporate Governance" elsewhere in this Annual Report on Form 10-K. Director compensation during 2018 consisted of a $75,000 cash retainer and an award of common units under the 2017 Plan. The units awarded to Board members are fully vested and not subject to forfeiture; however, the Board members had the option in advance of receipt of the award to elect to defer settlement of the award until after 90 days following such director's retirement or earlier departure from the Board. In addition, members of Board committees received $5,000 for each committee served on, and each committee chairman received an additional $10,000 for acting as chairman.

The table below shows the directors' compensation for the year ended December 31, 2018:

Name of Director	Fees Earned or Paid in Cash	2017 Plan Common Unit Awards(1)	Total Compensation
Russell D. Gordy	$ 81,250	$ 69,811	$ 151,061
Jasvinder S. Khaira(2)	—	—	—
S. Reed Morian	75,000	69,811	144,811
Richard A. Navarre(3)	95,000	69,811	164,811
Corbin J. Robertson, III	75,000	69,811	144,811
Stephen P. Smith(3)	95,000	69,811	164,811
Leo A. Vecellio, Jr.	95,000	69,811	164,811
Paul B. Murphy, Jr.(4)	62,500	65,202	127,702
Galdino J. Claro(4)	70,833	65,202	136,035

(1) Amounts represent the grant date fair value of phantom unit awards determined in accordance with Accounting Standards Codification Topic 718 determined without regard to forfeitures. For information regarding the assumptions used in calculating these amounts, see Note 19 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.
(2) Mr. Khaira does not receive Board compensation as the Blackstone designee.
(3) Messrs. Navarre and Smith elected to defer settlement of their common units awarded under the 2017 Plan until 90 days following their respective retirements or earlier departures from the Board.
(4) Amounts prorated from March 2, 2018, the date Messrs. Murphy and Claro joined the Board.

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The table below shows the Cash Settled Phantom Units that vested in 2018 with respect to each Director, along with the value realized by each individual, including the DERs accruing from the February 2014 grant date. Each director, other than Messrs. Khaira, Murphy, and Claro also held 410 Cash Settled Phantom Units as of December 31, 2018.

Name of Director	Cash Settled Phantom Units	Value Realized on Vesting
Russell D. Gordy	389	$ 20,223
Jasvinder S. Khaira	—	—
S. Reed Morian	389	20,223
Richard A. Navarre	389	20,223
Corbin J. Robertson, III	389	20,223
Stephen P. Smith	389	20,223
Leo A. Vecellio, Jr.	389	20,223
Paul B. Murphy, Jr.	—	—
Galdino J. Claro	—	—

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2018, Messrs. Vecellio, Gordy, and Smith served on the CNG Committee. None of Messrs. Vecellio, Gordy, and Smith has ever been an officer or employee of NRP or GP Natural Resource Partners LLC. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has any executive officer serving as a member of our Board or CNG Committee.

Pay Ratio Disclosure

The Securities and Exchange Commission has adopted a rule requiring annual disclosure of the ratio of the median employee’s total annual compensation to the total annual compensation of the CEO.

The personnel providing services to us, including our executive officers, are employed by Quintana or Western Pocahontas. As of December 31, 2018, 57 such persons were providing services to us. We identified a new median service provider in 2018 by examining the 2018 total taxable compensation, as reflected in our payroll records as reported to the Internal Revenue Service on Form W-2, for all individuals who provided services to us as of December 31, 2018. The calculation does not include compensation paid to employees of the VantaCore construction aggregates business sold in December 2018. We did not make any assumptions, adjustments, or estimates with respect to total cash compensation or equity compensation and we did not annualize the compensation for any service providers that were not employed for all of 2018.

After identifying the median service provider based on total compensation, we calculated annual 2018 compensation for the median service provider using the same methodology used to calculate the Chief Executive Officer’s total compensation as reflected in the Summary Compensation Table above. The median service provider’s annual 2018 compensation was as follows:

Name	Year	Salary	Bonus	Non-Equity Incentive Plan Compensation	Phantom Unit Awards	All Other Compensation	Total
Median Service Provider	2018	$88,400	$20,000	$ —	$ —	$ 5,304	$113,704

Our 2018 ratio of Chief Executive Officer total compensation to our median service provider's total compensation is reasonably estimated to be 14:1.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following tables set forth, as of March 1, 2019, the amount and percentage of our common units and Preferred Units beneficially held by (1) each person known to us to beneficially own 5% or more of any class of our units, (2) by each of our directors and named executive officers and (3) by all directors and executive officers as a group. Unless otherwise noted, each of the named persons and members of the group has sole voting and investment power with respect to the units shown.

Name of Beneficial Owner	Common Units	Percentage of Common Units (1)	
Corbin J. Robertson, Jr. (2)	4,128,605	33.7	%
Premium Resources LLC (3)	4,128,599	33.7	%
JPMorgan Chase & Co. (4)	1,154,442	9.4	%
The Goldman Sachs Group, Inc. (5)	785,207	6.4	%
Craig W. Nunez	—	—	
Kathryn S. Wilson	—	—	
Christopher J. Zolas	—	—	
Perry W. Donahoo (6)	7,504	*	
Jennifer L. Odinet	—	—	
Galdino J. Claro	4,114	*	
Russell D. Gordy (7)	11,354	*	
Jasvinder S. Khaira	—	—	
S. Reed Morian	4,354	*	
Paul B. Murphy, Jr.	7,614	*	
Richard A. Navarre	1,000	*	
Corbin J. Robertson III (8)	177,144	1.4	%
Stephen P. Smith	355	*	
Leo A. Vecellio, Jr.	6,354	*	
Directors and Officers as a Group	4,341,844	35.4	%

*Less than one percent.

(1) Percentages based upon 12,261,199 common units issued and outstanding as of March 1, 2019. Unless otherwise noted, beneficial ownership is less than 1%.

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

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

(4) According to a Schedule 13G filing with the SEC on January 29, 2019, JPMorgan Chase & Co. holds sole voting power and sole dispositive power with respect to 1,154,442 common units in the Partnership. The business address of JPMorgan Chase & Co. is 270 Park Ave., New York, NY 10017.

(5) According to a Schedule13G filing with the SEC on February 7, 2019, The Goldman Sachs Group holds shared voting power and shared dispositive power with respect to 785,207 common units in the Partnership. The business address of The Goldman Sachs Group is 200 West Street, New York, NY 10282.

(6) Mr. Donahoo resigned as Chief Executive Officer—Construction Aggregates in December 2018 in connection with our sale of that business and is one of our Named Executive Officers for purposes of this Annual Report on Form

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

(8) Mr. Robertson III may be deemed to beneficially own 9,783 common units held CIII Capital Management, LLC, 10,000 common units held by BHJ Investments, 5,046 common units held by The Corbin James Robertson III 2009 Family Trust and 39 common units held by his spouse, Brooke Robertson. The address for CIII Capital Management, LLC is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002, the address for BHJ Investments is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002 and the address for The Corbin James Robertson III 2009 Family Trust is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002. The following common units are pledged as collateral for loans: 41,743 common units owned directly by Mr. Robertson III.

Name of Beneficial Owner	Preferred Units	Percentage of Preferred Units	
The Blackstone Group L.P. (1)	142,500	57	%
GoldenTree Asset Management, LP (2)	107,500	43	%

(1) The Preferred Units are owned by funds managed by The Blackstone Group L.P., whose address is 345 Park Ave, New York, NY 10154. Blackstone Group Management L.L.C. is the general partner of The Blackstone Group L.P., and is wholly owned by Blackstone’s senior managing directors and controlled by its founder, Stephen A. Schwarzman.

(2) The Preferred Units are owned by funds managed by GoldenTree Asset Management, LP, whose address is 300 Park Ave, New York, NY 10022. Steven A. Tananbaum serves as senior managing member of GoldenTree Asset Management LLC, the general partner of GoldenTree Asset Management, LP.

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

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

Omnibus Agreement

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

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

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

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

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

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

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

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

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

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

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

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

The omnibus agreement may be amended at any time by the general partner, with the concurrence of the conflicts committee. The respective obligations of the WPP Group under the omnibus agreement terminate when the WPP

Group and its affiliates cease to participate in the control of the general partner.

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Board Representation and Observation Rights Agreement

Effective on March 2, 2017 in connection with the closing of the issuance of the Preferred Units, we entered into the Board Observation and Representation Rights Agreement (the “Board Rights Agreement”) with Blackstone and GoldenTree. Pursuant to the Board Rights Agreement, Blackstone appoints one member to serve on the Board of Directors of GP Natural Resource Partners LLC and also appoints one observer to attend meetings of the Board. Blackstone's rights to appoint a member of the Board and an observer will terminate at such time as Blackstone, together with their affiliates, no longer own at least 20% of the total number of Preferred Units issued on the closing date, together with all PIK Units that have been issued but not redeemed (the "Minimum Preferred Unit Threshold"). Following the time that Blackstone (and their affiliates) no longer own the Minimum Preferred Unit Threshold and until such time as GoldenTree (together with their affiliates) no longer own the Minimum Preferred Unit Threshold, GoldenTree shall have the one-time option to appoint either one person to serve as a member of the Board or one person to serve as a Board observer. To the extent GoldenTree elects to appoint a Board member and later remove such Board member, GoldenTree may then elect to appoint a Board observer. For more information on the Preferred Units, including the rights of the holders thereof, see "Item 8. Financial Statements and Supplementary Data—Note 5. Class A Convertible Preferred Units and Warrants" elsewhere in this Annual Report on Form 10-K.

Transactions with Cline Group and Affiliates

On May 9, 2017, Adena Minerals, LLC (“Adena”), an affiliate of Christopher Cline (“Cline”) sold its 31% limited partner interest in our general partner to Great Northern Properties Limited Partnership and WPPLP (the “Adena Sale”). In connection with the Adena Sale, on May 9, 2017, the Investor Rights Agreement effective as of January 4, 2007 by and among Adena, NRP GP, GP LLC, and Robertson Coal Management (the “Investor Rights Agreement”) terminated pursuant to its terms. Also on May 9, 2017, the Restricted Business Contribution Agreement effective as of January 4, 2007, by and among Christopher Cline, Foresight Reserves LP, Adena, NRP, NRP GP, and NRP (Operating) LLC (the “RBCA”) terminated pursuant to the terms thereof. In addition, the rights of Adena and its affiliates under the Partnership’s partnership agreement are no longer in effect as a result of the Adena Sale (other than customary rights to indemnification).

As a result of the Adena Sale, we no longer consider Cline or his affiliates, including Foresight Energy, affiliates of NRP. For a summary of revenues that we have derived from the Cline relationship, including Foresight Energy LP, see "Item 8. "Item 8. Financial Statements and Supplementary Data—Note 15. Related Party Transactions—Cline Affiliates and Foresight Energy" elsewhere in this Annual Report on Form 10-K..

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd., which controls several private equity funds focused on investments in the energy business. NRP’s Board of Directors has adopted a formal conflicts policy that establishes the opportunities that will be pursued by NRP and those that will be pursued by Quintana Capital. The basic tenets of the policy are set forth below.

NRP’s business strategy has historically focused on:

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

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

NRP’s acquisition strategy also includes:

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

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

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NRP's business strategy does not, and is not expected to, include:

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

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

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

For so long as Corbin Robertson, Jr. remains both an affiliate of Quintana Capital and an executive officer or director of NRP or an affiliate of its general partner, before making an investment in an NRP Business, Quintana Capital has agreed to adhere to the following procedures:

- Quintana Capital will first offer such opportunity in its entirety to NRP. NRP may elect to pursue such investment wholly for its own account, to pursue the opportunity jointly with Quintana Capital or not to pursue such opportunity.
- If NRP elects not to pursue an NRP Business investment opportunity, Quintana Capital may pursue the investment for its own account on similar terms.
- NRP will undertake to advise Quintana Capital of its decision regarding a potential investment opportunity within 10 business days of the identification of such opportunity to the Conflicts Committee.

If the opportunity relates to the acquisition of a Shared Business, NRP and Quintana Capital will adhere to the following procedures:

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

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

A fund controlled by Quintana Capital owns an interest in Corsa Coal Corp, a coal mining company traded on the TSX Venture Exchange that is one of our lessees in Tennessee. Corbin J. Robertson, III, one of our directors, was Chairman of the Board of Corsa through May 10, 2017. In addition, in May 2017, a subsidiary of Alpha Natural Resources assigned two coal leases with us to Quinwood Coal Partners LP ("Quinwood"), an entity controlled by Mr. Robertson, III. In connection with this lease assignment, Quinwood forfeited the historical recoupable balance related to this property.

For more information on our relationship with Corsa Coal and Quinwood, see "Item 8. Financial Statements and Supplementary Data—Note 15. Related Party Transactions—Quintana Capital Group GP, Ltd." and —Quinwood Coal Company Royalty.

Office Building in Huntington, West Virginia

We lease an office building in Huntington, West Virginia from Western Pocahontas Properties Limited Partnership. The initial 10-year term of the lease expired at the end of 2018. On January 1, 2019 we entered into a new lease on the building for a five-year base term, with five additional five-year renewal options. During the years ended December 31, 2018 and 2017, we paid approximately $0.6 million in rent each year to Western Pocahontas under the lease.

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Relationship with Cadence Bank, N.A.

Paul B. Murphy, Jr. one of the members of the Board of Directors of GP Natural Resource Partners LLC, is the Chairman of Cadence Bank, N.A., which is a lender under NRP Operating's revolving credit facility and has received customary fees and interest payments in connection therewith. During the years ended December 31, 2018 and 2017, we paid approximately $0.6 million and $0.3 million, respectively in interest and fees under the credit facility to Cadence Bank, N.A.

Conflicts of Interest

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

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

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

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

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

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

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

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

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

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

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;
- the issuance of additional common units; and
- the creation, reduction or increase of reserves in any quarter.

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

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

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

We do not have any officers or employees. We rely on officers and employees of GP Natural Resource Partners LLC and its affiliates.

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

We reimburse our general partner and its affiliates for expenses.

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

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

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

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

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

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

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

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

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

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

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

Our general partner's affiliates may compete with us.

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

The Conflicts Committee Charter is available upon request.

Director Independence

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

Review, Approval or Ratification of Transactions with Related Persons

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

Pursuant to our Code of Business Conduct and Ethics, conflicts of interest are prohibited as a matter of policy, except under guidelines approved by the Board and as provided in the Omnibus Agreement and our partnership agreement. For the years ended December 31, 2018 and 2017, there were no transactions where such guidelines were not followed.

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ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit Committee of the Board of Directors of GP Natural Resource Partners LLC recommended and we engaged Ernst & Young LLP to audit our accounts and assist with tax work for fiscal 2018 and 2017. All of our audit, audit-related fees and tax services have been approved by the Audit Committee of our Board of Directors. The following table presents fees for professional services rendered by Ernst &Young LLP:

	2018	2017
Audit Fees (1)	$957,272	$1,049,905
Tax Fees (2)	501,426	772,449
All Other Fees (3)	—	1,820

(1) Audit fees include fees associated with the annual integrated audit of our consolidated financial statements and internal controls over financial reporting, separate audits of subsidiaries and reviews of our quarterly financial statement for inclusion in our Form 10-Q and comfort letters; consents; work related to acquisitions; assistance with and review of documents filed with the SEC.

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

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

Audit and Non-Audit Services Pre-Approval Policy

I. Statement of Principles

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

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

For both types of pre-approval, the Audit Committee will consider whether such services are consistent with the SEC’s rules on auditor independence. The Audit Committee will also consider whether the independent auditor is best positioned to provide the most effective and efficient service for reasons such as its familiarity with our business, employees, culture, accounting systems, risk profile and other factors, and whether the service might enhance the

Partnership's ability to manage or control risk or improve audit quality. All such factors will be considered as a whole, and no one factor will necessarily be determinative.

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

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

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

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

II. Delegation

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

III. Audit Services

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

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

IV. Audit-related Services

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

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V. Tax Services

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

VI. Pre-Approval Fee Levels or Budgeted Amounts

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

VII. Procedures

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

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

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

(a)(3) Ciner Wyoming LLC Financial Statements

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

(a)(4) Exhibits

Exhibit Number	Description
2.1	Purchase Agreement, dated as of January 23, 2013, by and among Anadarko Holding Company, Big Island Trona Company, NRP Trona LLC and NRP (Operating) LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on January 25, 2013).
2.2	Purchase and Sale Agreement dated as of November 16, 2018, by and between NRP (Operating) LLC and VantaCore Intermediate Holdings LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on November 20, 2018).
3.1	Fifth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of March 2, 2017 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on March 6, 2017).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of December 16, 2011 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on December 16, 2011).
3.3	Fifth Amended and Restated Limited Liability Company Agreement of GP Natural Resource Partners LLC, dated as of October 31, 2013 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on October 31, 2013).
3.4	Amended and Restated Limited Liability Company Agreement of NRP (Operating) LLC, dated as of October 17, 2002 (incorporated by reference to Exhibit 3.4 of Annual Report on Form 10-K for the year ended December 31, 2002).
3.5	Certificate of Limited Partnership of Natural Resource Partners L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 filed April 19, 2002, File No. 333-86582).
4.1	Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the Purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed June 23, 2003).
4.2	First Amendment, dated as of July 19, 2005, to Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed on July 20, 2005).
4.3	Second Amendment, dated as of March 28, 2007, to Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed on March 29, 2007).
4.4	First Supplement to Note Purchase Agreement, dated as of July 19, 2005 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K

	filed on July 20, 2005).
4.5	Second Supplement to Note Purchase Agreement, dated as of March 28, 2007 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 29, 2007).
4.6	Third Supplement to Note Purchase Agreement, dated as of March 25, 2009 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 26, 2009).
4.7	Fourth Supplement to Note Purchase Agreement, dated as of April 20, 2011 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on April 21, 2011).

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Exhibit Number	Description
4.8	Subsidiary Guarantee of Senior Notes of NRP (Operating) LLC, dated June 19, 2003 (incorporated by reference to Exhibit 4.5 to Current Report on Form 8-K filed June 23, 2003).
4.9	Form of Series A Note (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed June 23, 2003).
4.10	Form of Series D Note (incorporated by reference to Exhibit 4.12 to Annual Report on Form 10-K filed February 28, 2007).
4.11	Form of Series E Note (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed March 29, 2007).
4.12	Form of Series F Note (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed May 7, 2009).
4.13	Form of Series G Note (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed May 7, 2009).
4.14	Form of Series H Note (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed May 5, 2011).
4.15	Form of Series I Note (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed May 5, 2011).
4.16	Form of Series J Note (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 15, 2011).
4.17	Form of Series K Note (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on October 3, 2011).
4.18	Registration Rights Agreement, dated as of January 23, 2013, by and among Natural Resource Partners L.P. and the Investors named therein (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on January 25, 2013).
4.19	Third Amendment, dated as of June 16, 2015, to Note Purchase Agreements, dated as of June 19, 2003, among NRP (Operating) LLC and the holders named therein (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 18, 2015).
4.20	Fourth Amendment, dated as of September 9, 2016, to Note Purchase Agreements, dated as of June 19, 2003, among NRP (Operating) LLC and the holders named therein (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 12, 2016).
4.21	Indenture, dated March 2, 2017, by and among Natural Resource Partners L.P. and NRP Finance Corporation, as issuers, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed on March 6, 2017).
4.22	Form of 10.500% Senior Notes due 2018 (contained in Exhibit 1 to Exhibit 4.21).
4.23	Registration Rights Agreement dated as of March 2, 2017, by and among Natural Resource Partners L.P. and the Purchasers named therein (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed on March 6, 2017).
4.24	Form of Warrant to Purchase Common Units (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 6, 2017).
10.1	Third Amended and Restated Credit Agreement, dated as of June 16, 2015, by and among NRP (Operating) LLC, the lenders party thereto, Citibank, N.A. as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc. and Wells Fargo Securities LLC as Joint Lead Arrangers and Joint Bookrunners, and Citibank, N.A., as Syndication Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on June 18, 2015).
10.2	

	First Amendment, dated as of June 3, 2016, to Third Amended and Restated Credit Agreement, dated as of June 16, 2015, by and among NRP (Operating) LLC, the lenders party thereto, Citibank, N.A. as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc. and Wells Fargo Securities LLC as Joint Lead Arrangers and Joint Bookrunners, and Citibank, N.A., as Syndication Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on June 7, 2016).
10.3	First Amended and Restated Omnibus Agreement, dated as of April 22, 2009, by and among Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation, Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed May 7, 2009).
10.4	Limited Liability Company Agreement of Ciner Wyoming LLC, dated June 30, 2014 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed by Ciner Resources LP on July 2, 2014).

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Exhibit Number	Description
10.5	Amendment No. 1 to the Limited Liability Company Agreement of Ciner Wyoming LLC dated November 5, 2015 (incorporated by reference to Exhibit 10.22 to Annual Report on Form 10-K filed by Ciner Resources LP on March 11, 2016).
10.6	Second Amendment, dated as of March 2, 2017, to Third Amended and Restated Credit Agreement, dated as of June 16, 2015, by and among NRP (Operating) LLC, the lenders party thereto, Citibank, N.A. as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc. and Wells Fargo Securities LLC as Joint Lead Arrangers and Joint Bookrunners, and Citibank, N.A., as Syndication Agent (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed on March 6, 2017).
10.7	Preferred Unit and Warrant Purchase Agreement, dated as of February 22, 2017, by and among Natural Resource Partners L.P. and the Purchasers named therein (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on March 6, 2017.
10.8	Exchange and Purchase Agreement, dated as of February 22, 2017, by and among Natural Resource Partners L.P., NRP Finance Corporation and the Consenting Holders named therein (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K filed on March 6, 2017.
10.9	Board Representation and Observation Rights Agreement dated as of March 2, 2017, by and among Natural Resource Partners L.P., Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, BTO Carbon Holdings L.P. and the GoldenTree Purchasers named therein (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on March 6, 2017)
10.10	Settlement Agreement dated October 19, 2018 by and among WPP LLC and Foresight Energy LP (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2018 filed by Foresight Energy LP on November 7, 2018).
10.11+	Natural Resource Partners Second Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on January 17, 2008).
10.12+	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2007).
10.13+	Natural Resource Partners L.P. 2017 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on January 17, 2018).
10.14+	Form of Phantom Unit Award Agreement (Employees and Service Providers) (incorporated by reference to Exhibit 4.5 to Registration Statement on Form S-8 filed on February 9, 2018).
10.15+	Form of Phantom Unit Award Agreement (Directors) (incorporated by reference to Exhibit 4.6 to Registration Statement on Form S-8 filed on February 9, 2018).
10.16+	Employment Agreement dated August 16, 2017, between Quintana Minerals Corporation and Wyatt L. Hogan (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on November 8, 2017).
10.17*+	General Release of Claims between Quintana Minerals Corporation and Perry W. Donahoo.
21.1*	List of Subsidiaries of Natural Resource Partners L.P.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Deloitte & Touche LLP.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.
95.1*	Mine Safety Disclosure.
99.1*	

<u>Financial Statements of Ciner Wyoming LLC as of December 31, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016.</u>

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Exhibit Number	Description
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

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

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SIGNATURES

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

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

Date: March 7, 2019

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

Date: March 7, 2019

By: /s/ CHRISTOPHER J. ZOLAS
Christopher J. Zolas
Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: March 7, 2019

By: /s/ JENNIFER L. ODINET
Jennifer L. Odinet
Chief Accounting Officer
(Principal Accounting Officer)

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: March 7, 2019

/s/ GALDINO J. CLARO
Galdino J. Claro
Director

Date: March 7, 2019

/s/ RUSSELL D. GORDY
Russell D. Gordy
Director

Date: March 7, 2019

Jasvinder S. Khaira
Director

Date: March 7, 2019

/s/ S. REED MORIAN
S. Reed Morian
Director

Date: March 7, 2019

/s/ PAUL B. MURPHY, JR.
Paul B. Murphy, Jr.
Director

Date: March 7, 2019

/s/ RICHARD A. NAVARRE
Richard A. Navarre
Director

Date: March 7, 2019

/s/ CORBIN J. ROBERTSON III
Corbin J. Robertson III
Director

Date: March 7, 2019

/s/ STEPHEN P. SMITH
Stephen P. Smith
Director

Date: March 7, 2019

/s/ LEO A. VECELLIO, JR.
Leo A. Vecellio, Jr.
Director