UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 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: 001-34892

Rhino Resource Partners LP
(Exact name of registrant as specified in its charter)

Delaware	**27-2377517**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
424 Lewis Hargett Circle, Suite 250 **Lexington, KY**	**40503**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(859) 389-6500**
Securities registered pursuant to Section 12(b) of the Act:

None

Securities registered pursuant to Section 12(g) of the Act:
Common Units representing Limited Partner Interests

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

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

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

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

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

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

Large accelerated filer [ ]	Accelerated filer [ ]	Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [X]

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 Securities Act. [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes [ ] No [X]

As of June 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's equity held by non-affiliates of the registrant was approximately $2.1 million based on the price at which the registrant's common units were last sold on the OTCQB Marketplace on such date. As of March 15, 2019, the registrant had 13,098,353 common units, 1,143,686 subordinated units and 1,500,000 Series A preferred units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K

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GLOSSARY OF KEY TERMS

ash: Inorganic material consisting of iron, alumina, sodium and other incombustible matter that are contained in coal. The composition of the ash can affect the burning characteristics of coal.

assigned reserves: Proven and probable reserves that have the permits and infrastructure necessary for mining.

as received: Represents an analysis of a sample as received at a laboratory.

Btu: *British thermal unit, or Btu,* is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

Central Appalachia: Coal producing area in eastern Kentucky, western Virginia and southern West Virginia.

coal seam: Coal deposits occur in layers typically separated by layers of rock. Each layer is called a "seam." A seam can vary in thickness from inches to a hundred feet or more.

coke: A hard, dry carbon substance produced by heating coal to a very high temperature in the absence of air. Coke is used in the manufacture of iron and steel.

fossil fuel: A hydrocarbon such as coal, petroleum or natural gas that may be used as a fuel.

GAAP: Generally accepted accounting principles in the United States.

high-vol metallurgical coal: Metallurgical coal that has a volatility content of 32% or greater of its total weight.

Illinois Basin: Coal producing area in Illinois, Indiana and western Kentucky.

limestone: A rock predominantly composed of the mineral calcite (calcium carbonate ($CaCO_3$)).

lignite: The lowest rank of coal. It is brownish-black with high moisture content commonly above 35% by weight and heating value commonly less than 8,000 Btu.

low-vol metallurgical coal: Metallurgical coal that has a volatility content of 17% to 22% of its total weight.

mid-vol metallurgical coal: Metallurgical coal that has a volatility content of 23% to 31% of its total weight.

Metallurgical, or "met", coal: The various grades of coal suitable for carbonization to make coke for steel manufacture. Its quality depends on four important criteria: volatility, which affects coke yield; the level of impurities including sulfur and ash, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Metallurgical coal typically has a particularly high Btu but low ash and sulfur content.

non-reserve coal deposits: Non-reserve coal deposits are coal-bearing bodies that have been sufficiently sampled and analyzed in trenches, outcrops, drilling and underground workings to assume continuity between sample points, and therefore warrant further exploration stage work. However, this coal does not qualify as a commercially viable coal reserve as prescribed by standards of the SEC until a final comprehensive evaluation based on unit cost per ton, recoverability and other material factors concludes legal and economic feasibility. Non-reserve coal deposits may be classified as such by either limited property control or geologic limitations, or both.

Northern Appalachia: Coal producing area in Maryland, Ohio, Pennsylvania and northern West Virginia.

overburden: Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

preparation plant: Usually located on a mine site, although one plant may serve several mines. A preparation plant is a facility for crushing, sizing and washing coal to prepare it for use by a particular customer. The washing process separates higher ash coal and may also remove some of the coal's sulfur content.

probable (indicated) coal reserves: Coal reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

proven (measured) coal reserves: Coal reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

reclamation: The process of restoring land to its prior condition, productive use or other permitted condition following mining activities. The process commonly includes "re-contouring" or reshaping the land to its approximate original contour, restoring topsoil and planting native grass and shrubs. Reclamation operations are typically conducted concurrently with mining operations, but the majority of reclamation costs are incurred once mining operations cease. Reclamation is closely regulated by both state and federal laws.

reserve: That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

steam coal: Coal used by power plants and industrial steam boilers to produce electricity, steam or both. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

sulfur: One of the elements present in varying quantities in coal that contributes to environmental degradation when coal is burned. Sulfur dioxide (SO2) is produced as a gaseous by-product of coal combustion.

surface mine: A mine in which the coal lies near the surface and can be extracted by removing the covering layer of soil overburden. Surface mines are also known as open-pit mines.

tons: A "short" or net ton is equal to 2,000 pounds. A "long" or British ton is 2,240 pounds. A "metric" tonne is approximately 2,205 pounds. The short ton is the unit of measure referred to in this report.

Western Bituminous region: Coal producing area located in western Colorado and eastern Utah.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This report contains "forward-looking statements." Statements included in this report that are not historical facts, that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as statements regarding our future financial position, expectations with respect to our liquidity, capital resources and ability to continue as a going concern, plans for growth of the business, future capital expenditures, references to future goals or intentions or other such references are forward-looking statements. These statements can be identified by the use of forward-looking terminology, including "may," "believe," "expect," "anticipate," "estimate," "continue," or similar words. These statements are made by us based on our past experience and our perception of historical trends, current conditions and expected future developments as well as other considerations we believe are reasonable as and when made. Whether actual results and developments in the future will conform to our expectations is subject to numerous risks and uncertainties, many of which are beyond our control. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in these statements. Known material factors that could cause our actual results to differ from those in the forward-looking statements are those described in "Part 1, Item 1A. Risk Factors." The following factors are among those that may cause actual results to differ materially from our forward-looking statements:

- our ability to maintain adequate cash flow to fund our capital expenditures, meet working capital needs and maintain and grow our operations;
- our future levels of indebtedness and compliance with debt covenants;
- declines in coal prices, which depend upon several factors such as the supply of domestic and foreign coal, the demand for domestic and foreign coal, governmental regulations, price and availability of alternative fuels for electricity generation and prevailing economic conditions;
- our ability to comply with the qualifying income requirement necessary to maintain our status as a partnership for U.S. federal income tax purposes;
- declines in demand for electricity and coal;
- current and future environmental laws and regulations, which could materially increase operating costs or limit our ability to produce and sell coal;
- extensive government regulation of mine operations, especially with respect to mine safety and health, which imposes significant actual and potential costs;
- difficulties in obtaining and/or renewing permits necessary for operations;
- a variety of operating risks, such as unfavorable geologic conditions, adverse weather conditions and natural disasters, mining and processing equipment unavailability, failures and unexpected maintenance problems and accidents, including fire and explosions from methane;
- poor mining conditions resulting from the effects of prior mining; the availability and costs of key supplies and commodities such as steel, diesel fuel and explosives;
- fluctuations in transportation costs or disruptions in transportation services, which could increase competition or impair our ability to supply coal;
- a shortage of skilled labor, increased labor costs or work stoppages;
- our ability to secure or acquire new or replacement high-quality coal reserves that are economically recoverable;
- material inaccuracies in our estimates of coal reserves and non-reserve coal deposits;
- existing and future laws and regulations regulating the emission of sulfur dioxide and other compounds, which could affect coal consumers and reduce demand for coal;
- federal and state laws restricting the emissions of greenhouse gases;
- our ability to acquire or failure to maintain, obtain or renew surety bonds used to secure obligations to reclaim mined property;
- our dependence on a few customers and our ability to find and retain customers under favorable supply contracts;
- changes in consumption patterns by utilities away from the use of coal, such as changes resulting from low natural gas prices;
- changes in governmental regulation of the electric utility industry;
- defects in title in properties that we own or losses of any of our leasehold interests;
- our ability to retain and attract senior management and other key personnel;
- material inaccuracy of assumptions underlying reclamation and mine closure obligations; and
- weakness in global economic conditions.

Readers are cautioned not to place undue reliance on forward-looking statements. The forward-looking statements speak only as of the date made, and we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Unless the context clearly indicates otherwise, references in this report to "Rhino Predecessor," "we," "our," "us" or similar terms when used for periods prior to the completion of the initial public offering of common units of Rhino Resource Partners LP on October 5, 2010 (the "IPO") refer to Rhino Energy LLC and its subsidiaries. When used for periods subsequent to the completion of the IPO, "we,""our,""us," or similar terms refer to Rhino Resource Partners LP and its subsidiaries. References to our "general partner" refer to Rhino GP LLC, the general partner of Rhino Resource Partners LP.

Item 1. Business.

We are a diversified coal producing limited partnership formed in Delaware that is focused on coal and energy related assets and activities. We produce, process and sell high quality coal of various steam and metallurgical grades from multiple coal producing basins in the United States. We market our steam coal primarily to electric utility companies as fuel for their steam powered generators. Customers for our metallurgical coal are primarily steel and coke producers who use our coal to produce coke, which is used as a raw material in the steel manufacturing process.

We have a geographically diverse asset base with coal reserves located in Central Appalachia, Northern Appalachia, the Illinois Basin and the Western Bituminous region. As of December 31, 2018, we controlled an estimated 268.5 million tons of proven and probable coal reserves, consisting of an estimated 214.0 million tons of steam coal and an estimated 54.5 million tons of metallurgical coal. Proven and probable coal reserves increased approximately 15.8 million tons from 2017 to 2018 primarily as the result of the revised economic feasibility of our non-reserve coal deposits. In addition, as of December 31, 2018, we controlled an estimated 164.1 million tons of non-reserve coal deposits, which decreased primarily due to the reclassification of non-reserve coal deposits to proven and probable reserves. Periodically, we retain outside experts to independently verify our coal reserve and our non-reserve coal deposit estimates. The most recent audit by an independent engineering firm of our coal reserve and non-reserve coal deposit estimates was completed by Marshall Miller & Associates, Inc. as of December 31, 2018, and covered a majority of the coal reserves and non-reserve coal deposits that we controlled as of such date. We intend to continue to periodically retain outside experts to assist management with the verification of our estimates of our coal reserves and non-reserve coal deposits going forward.

We operate underground and surface mines located in Kentucky, Ohio, West Virginia and Utah. The number of mines that we operate will vary from time to time depending on a number of factors, including the existing demand for and price of coal, depletion of economically recoverable reserves and availability of experienced labor.

For the year ended December 31, 2018, we produced approximately 4.4 million tons of coal from continuing operations and sold approximately 4.6 million tons of coal from continuing operations.

Our principal business strategy is to safely, efficiently and profitably produce and sell both steam and metallurgical coal from our diverse asset base in order to resume, and, over time, increase our quarterly cash distributions. In addition, we continue to seek opportunities to expand and diversify our operations through strategic acquisitions, including the acquisition of long-term, cash generating natural resource assets. We believe that such assets will allow us to grow our cash available for distribution and enhance the stability of our cash flow.

Current Liquidity and Outlook

As of December 31, 2018, our available liquidity was $6.2 million. We also have a delayed draw term loan commitment in the amount of $40 million contingent upon the satisfaction of certain conditions precedent specified in the financing agreement discussed below.

On December 27, 2017, we entered into a Financing Agreement ("Financing Agreement"), which provides us with a multi-draw loan in the aggregate principal amount of $80 million. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the Financing Agreement and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement. We used approximately $17.3 million of the net proceeds thereof to repay all amounts outstanding and terminate the Amended and Restated Credit Agreement with PNC Bank, National Association, as Administrative Agent. The Financing Agreement terminates on December 27, 2020. For more information about our new Financing Agreement, please read "— Recent Developments—Financing Agreement."

We continue to take measures, including the suspension of cash distributions on our common and subordinated units and cost and productivity improvements, to enhance and preserve our liquidity so that we can fund our ongoing operations and necessary capital expenditures and meet our financial commitments and debt service obligations.

Recent Developments

Financing Agreement

On December 27, 2017, we entered into a Financing Agreement with Cortland Capital Market Services LLC, as Collateral Agent and Administrative agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders therein (the "Lenders"), pursuant to which Lenders agreed to provide us with a multi-draw term loan in the aggregate principal amount of $80 million, subject to the terms and conditions set forth in the Financing Agreement. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the Financing Agreement (the "Effective Date Term Loan Commitment") and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement ("Delayed Draw Term Loan Commitment"). Loans made pursuant to the Financing Agreement will be secured by substantially all of our assets. The Financing Agreement terminates on December 27, 2020. For more information about our Financing Agreement, please read "Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Financing Agreement."

On April 17, 2018, we amended the Financing Agreement to allow for certain activities including a sale leaseback of certain pieces of equipment, the due date for the lease consents was extended to June 30, 2018 and confirmation of the distribution to holders of the Series A preferred units of $6.0 million (accrued in our audited consolidated financial statements at December 31, 2017). Additionally, the amendments provided that we could sell additional shares of Mammoth Energy Services, Inc. (NASDAQ: TUSK) (“Mammoth, Inc.”) and retain 50% of the proceeds with the other 50% used to reduce debt. We reduced the debt by $3.4 million with proceeds from the sale of Mammoth Inc. stock in the second quarter of 2018.

On July 27, 2018, we entered into a consent with our Lenders related to the Financing Agreement. The consent included the lenders agreement to make a $5 million loan from the Delayed Draw Term Loan Commitment, which was repaid in full on October 26, 2018 pursuant to the terms of the consent. The consent also included a waiver of the requirements relating to the use of proceeds of any sale of the shares of Mammoth Inc. set forth in the consent to the Financing Agreement, dated as of April 17, 2018 and also waived any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended June 30, 2018.

On November 8, 2018, we entered into a consent with our Lenders related to the Financing Agreement. The consent includes the lenders agreement to waive any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended September 30, 2018.

On December 20, 2018, we entered into a limited waiver and consent (the “Waiver”) to the Financing Agreement. The Waiver relates to our sales of certain real property in Western Colorado, the net proceeds of which are required to be used to reduce the debt under the Financing Agreement. As of the date of the Waiver, we had sold 9 individual lots in smaller transactions. Rather than transmitting net proceeds with respect to each individual transaction, we agreed with the Lenders in principle to delay repayment until an aggregate payment could be made at the end of 2018. On December 18, 2018, we used the sale proceeds of approximately $379,000 to reduce the debt. The Waiver (i) contains a ratification by the Lenders of the sale of the individual lots to date and waives the associated technical defaults under the Financing Agreement for not making immediate payments of net proceeds therefrom, (ii) permits the sale of certain specified additional lots and (iii) subject to Lender consent, permits the sale of other lots on a going forward basis. The net proceeds of future sales will be held by us until a later date to be determined by the Lenders.

On February 13, 2019, we entered into a second amendment (“Amendment”) to the Financing Agreement. The Amendment provides the Lender’s consent for us to pay a one-time cash distribution on February 14, 2019 to the Series A Preferred Unitholders an amount not to exceed approximately $3.2 million. The Amendment allows us to sell our remaining shares of Mammoth Energy Services, Inc. and utilize the proceeds for payment of the one-time cash distribution to the Series A Preferred Unitholders and waives the requirement to use such proceeds to prepay the outstanding principal amount outstanding under the Financing Agreement. The Amendment also waives any Event of Default that has or would otherwise arise under Section 9.01(c) of the Financing Agreement solely by reason of us failing to comply with the Fixed Charge Coverage Ratio covenant in Section 7.03(b) of the Financing Agreement for the fiscal quarter ending December 31, 2018. The Amendment includes an amendment fee of approximately $0.6 million payable by us on May 13, 2019 and an exit fee equal to 1% of the principal amount of the term loans made under the Financing Agreement that is payable on the earliest of (w) the final maturity date of the Financing Agreement, (x) the termination date of the Financing Agreement, (y) the acceleration of the obligations under the Financing Agreement for any reason, including, without limitation, acceleration in accordance with Section 9.01 of the Financing Agreement, including as a result of the commencement of an insolvency proceeding and (z) the date of any refinancing of the term loan under the Financing Agreement. The Amendment amends the definition of the Make-Whole Amount under the Financing Agreement to extend the date of the Make-Whole Amount period to December 31, 2019.

Common Unit Warrants

We entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. The warrant agreement included the issuance of a total of 683,888 warrants of our common units ("Common Unit Warrants") at an exercise price of $1.95 per unit, which was the closing price of our units on the OTC market as of December 27, 2017. The Common Unit Warrants have a five year expiration date. The Common Unit Warrants and the Rhino common units after exercise are both transferable, subject to applicable US securities laws. The Common Unit Warrant exercise price is $1.95 per unit, but the price per unit will be reduced by future common unit distributions and other further adjustments in price included in the warrant agreement for transactions that are dilutive to the amount of Rhino's common units outstanding. The warrant agreement includes a provision for a cashless exercise where the warrant holders can receive a net number of common units. Per the warrant agreement, the warrants are detached from the Financing Agreement and fully transferable.

Letter of Credit Facility – PNC Bank

On December 27, 2017, we entered into a master letter of credit facility, security agreement and reimbursement agreement (the "LoC Facility Agreement") with PNC Bank, National Association ("PNC"), pursuant to which PNC agreed to provide us with a facility for the issuance of standby letters of credit used in the ordinary course of our business (the "LoC Facility"). The LoC Facility Agreement provided that we pay a quarterly fee at a rate equal to 5% per annum calculated based on the daily average of letters of credit outstanding under the LoC Facility, as well as administrative costs incurred by PNC and a $100,000 closing fee. The LoC Facility Agreement provided that we reimburse PNC for any drawing under a letter of credit by a specified beneficiary as soon as possible after payment was made. Our obligations under the LoC Facility Agreement were secured by a first lien security interest on a cash collateral account that was required to contain no less than 105% of the face value of the outstanding letters of credit. In the event the amount in such cash collateral account was insufficient to satisfy our reimbursement obligations, the amount outstanding would bear interest at a rate per annum equal to the Base Rate (as that term was defined in the LoC Facility Agreement) plus 2.0%. We would indemnify PNC for any losses which PNC may have incurred as a result of the issuance of a letter of credit or PNC's failure to honor any drawing under a letter of credit, subject in each case to certain exceptions. We provided cash collateral to our counterparties during the third quarter of 2018 and as of September 30, 2018, the LoC Facility was terminated. We had no outstanding letters of credit as of December 31, 2018.

Distribution Suspension

Beginning with the quarter ended June 30, 2015 and continuing through the quarter ended December 31, 2018, we have suspended the cash distribution on our common units. For each of the quarters ended September 30, 2014, December 31, 2014 and March 31, 2015, we announced cash distributions per common unit at levels lower than the minimum quarterly distribution. We have not paid any distribution on our subordinated units for any quarter after the quarter ended March 31, 2012. The distribution suspension and prior reductions were the result of prolonged weakness in the coal markets, which has continued to adversely affect our cash flow.

Pursuant to our partnership agreement, our common units accrue arrearages every quarter when the distribution level is below the minimum level of $4.45 per unit. Since our distributions for the quarters ended September 30, 2014, December 31, 2014 and March 31, 2015 were below the minimum level and we altogether suspended the distribution beginning with the quarters ended June 30, 2015 through December 31, 2018, we have accumulated arrearages at December 31, 2018 related to the common unit distribution of approximately $673.1 million.

History

Our predecessor was formed in April 2003 by Wexford Capital. We were formed in April 2010 to own and control the coal properties and related assets owned by Rhino Energy LLC. On October 5, 2010, we completed our IPO. Our common units were originally listed on the New York Stock Exchange under the symbol "RNO". In connection with the IPO, Wexford contributed their membership interests in Rhino Energy LLC to us, and in exchange we issued subordinated units representing limited partner interests in us and common units to Wexford and issued incentive distribution rights to our general partner. Through a series of transactions completed in the first quarter of 2016, Royal Energy Resources, Inc. ("Royal") acquired a majority ownership and control of the Partnership and 100% ownership of the Partnership's general partner.

Since April 2003, we have completed numerous coal asset acquisitions with a total purchase price of approximately $357.5 million. Through these acquisitions and coal lease transactions, we have substantially increased our proven and probable coal reserves and non-reserve coal deposits. In addition, we have successfully grown our production through internal development projects.

On April 27, 2016, the NYSE filed with the SEC a notification of removal from listing and registration on Form 25 to delist our common units and terminate the registration of our common units under Section 12(b) of the Securities Exchange Act of 1934. The delisting became effective on May 9, 2016. Our common units trade on the OTCQB Marketplace under the ticker symbol “RHNO.”

We are managed by the board of directors and executive officers of our general partner. Our operations are conducted through, and our operating assets are owned by, our wholly owned subsidiary, Rhino Energy LLC, and its subsidiaries.

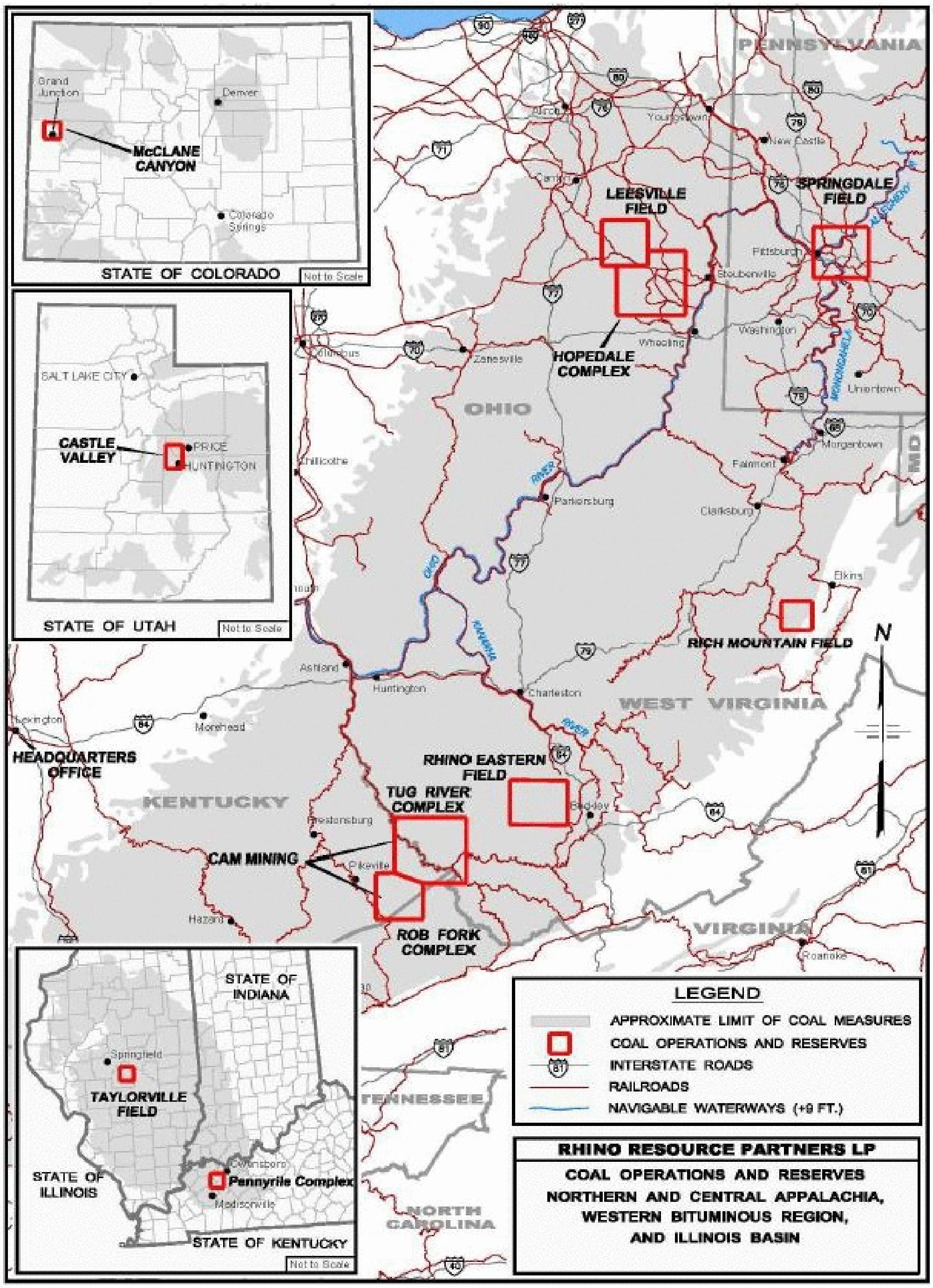
Coal Operations

Mining and Leasing Operations

As of December 31, 2018, we operated two mining complexes located in Central Appalachia (Tug River and Rob Fork). In addition during 2018, we operated one mining complex located in Northern Appalachia (Hopedale). The other Northern Appalachia mining complex, Sands Hill Mining, was sold in November 2017. In the Western Bituminous region, we operated one mining complex located in Emery and Carbon Counties, Utah (Castle Valley). We also operated a mining complex in the Illinois Basin, our Riveredge mine at our Pennyrile mining complex. (See Note 4 of the consolidated financial statements included elsewhere in this annual report for further information on the disposition of Sands Hill Mining)

We define a mining complex as a central location for processing raw coal and loading coal into railroad cars, barges or trucks for shipment to customers. These mining complexes include five active preparation plants and/or loadouts, each of which receive, blend, process and ship coal that is produced from one or more of our active surface and underground mines. All of the preparation plants are modern plants that have both coarse and fine coal cleaning circuits.

The following map shows the location of our coal mining and leasing operations as of December 31, 2018 (Note: the McClane Canyon mine in Colorado was permanently idled at December 31, 2013):



Our surface mines include area mining and contour mining. These operations use truck and wheel loader equipment fleets along with large production tractors and shovels. Our underground mines utilize the room and pillar mining method. These operations generally consist of one or more single or dual continuous miner sections which are made up of the continuous miner, shuttle cars, roof bolters, feeder and other support equipment. We currently own most of the equipment utilized in our mining operations. We employ preventive maintenance and rebuild programs to ensure that our equipment is modern and well-maintained. The rebuild programs are performed either by an on-site shop or by third-party manufacturers.

The following table summarizes our mining complexes and production from continuing operations by region as of December 31, 2018.

Region	Preparation Plants and Loadouts	Transportation to Customers(1)	Number and Type of Active Mines(2)	Tons Produced for the Year Ended December 31, 2018 (3)
				(in million tons)
Central Appalachia				
Tug River Complex (KY, WV)	Tug Fork & Jamboree(4)	Truck, Barge, Rail (NS)	2S	1.2
Rob Fork Complex (KY)	Rob Fork	Truck, Barge, Rail (CSX)	1U,1S	0.5
Northern Appalachia(5)				
Hopedale Complex (OH)	Nelms	Truck, Rail (OHC, WLE)	1U	0.4
Illinois Basin				
Taylorville Field (IL)	n/a	Rail (NS)	—	—
Pennyrile Complex (KY)	Preparation plant & river loadout	Barge	1U	1.3
Western Bituminous				
Castle Valley Complex (UT)	Truck loadout	Truck	1U	1.0
McClane Canyon Mine (CO)(6)	n/a	Truck	—	—
Total			4U,3S	4.4

(1) NS = Norfolk Southern Railroad; CSX = CSX Railroad; OHC = Ohio Central Railroad; WLE = Wheeling & Lake Erie Railroad.

(2) Numbers indicate the number of active mines. U = underground; S = surface. All of our mines as of December 31, 2018 were company-operated.

(3) Total production based on actual amounts and not rounded amounts shown in this table.

(4) Jamboree includes only a loadout facility.

(5) The Sands Hill Mining complex was previously included in our Northern Appalachia region and was sold in November 2017.

(6) The McClane Canyon mine was permanently idled as of December 31, 2013.

Central Appalachia. For the year ended December 31, 2018, we operated two mining complexes located in Central Appalachia consisting of one active underground mine and three surface mines. For the year ended December 31, 2018, the mines at our Tug River and Rob Fork mining complexes produced an aggregate of approximately 1.2 million tons of steam coal and an estimated 0.5 million tons of metallurgical coal.

Tug River Mining Complex. Our Tug River mining complex is located in Kentucky and West Virginia bordering the Tug River. This complex produces coal from two company-operated surface mines, which includes one high-wall mining unit. Coal production from these operations is delivered to the Tug Fork preparation plant for processing and then transported by truck to the Jamboree rail loadout for blending and shipping. Coal suitable for direct-ship to customers is delivered by truck directly to the Jamboree rail loadout from the mine sites. The Tug Fork plant is a modern, 350 tons per hour preparation plant utilizing heavy media circuitry that is capable of cleaning coarse and fine coal size fractions. The Jamboree loadout is located on the Norfolk Southern Railroad and is a modern unit train, batch weigh loadout. This mining complex produced approximately 1.0 million tons of steam coal and approximately 0.2 million tons of metallurgical coal for the year ended December 31, 2018.

Rob Fork Mining Complex. Our Rob Fork mining complex is located in eastern Kentucky and produces coal from one company-operated surface mine and one company-operated underground mine. The Rob Fork mining complex is located on the CSX Railroad and consists of a modern preparation plant utilizing heavy media circuitry that is capable of cleaning coarse and fine coal size fractions and a unit train loadout with batch weighing equipment. The mining complex has significant blending capabilities allowing the blending of raw coals with washed coals to meet a wide variety of customers' needs. The Rob Fork mining complex produced approximately 0.2 million tons of steam coal and 0.3 million tons of metallurgical coal for the year ended December 31, 2018.

Northern Appalachia. For the year ended December 31, 2018, we operated one mining complex located in Northern Appalachia consisting of one company-operated underground mine. For the year ended December 31, 2018, the mine produced an aggregate of approximately 0.4 million tons of steam coal. We sold our Sands Hill Mining operation in November 2017, which consisted of one company-operated surface mine.

Hopedale Mining Complex. The Hopedale mining complex includes an underground mine located in Hopedale, Ohio approximately five miles northeast of Cadiz, Ohio. Coal produced from the Hopedale mine is cleaned at our Nelms preparation plant located on the Ohio Central Railroad and the Wheeling & Lake Erie Railroad and then shipped by train or truck to our customers. The infrastructure includes a full-service loadout facility. This underground mining operation produced approximately 0.4 million tons of steam coal for the year ended December 31, 2018.

Western Bituminous Region. We operate one mining complex in the Western Bituminous region that produces coal from an underground mine located in Emery and Carbon Counties, Utah. We also had one underground mine located in the Western Bituminous region in Colorado (McClane Canyon) that was permanently idled at the end of 2013.

Castle Valley Mining Complex. Our Castle Valley mining complex includes one underground mine located in Emery and Carbon Counties, Utah and include coal reserves and non-reserve coal deposits, underground mining equipment and infrastructure, an overland belt conveyor system, a loading facility and support facilities. We produced approximately 1.0 million tons of steam coal from one underground mine at this complex for the year ended December 31, 2018.

Illinois Basin. We operate one mining complex in the Illinois Basin region that produces coal from an underground mine located in Daviess and McLean counties in western Kentucky contiguous to the Green River. We also have an estimated 111.1 million of proven and probable reserves in the Taylorville Field area in the Illinois Basin that remain undeveloped.

Pennyrile Mining Complex. In mid-2014, we completed the initial construction of a new underground mining operation on the purchased property, referred to as our Pennyrile mining complex, which includes one underground mine, a preparation plant and river loadout facility. The property is adjacent to a navigable waterway, which allows for exports to non-U.S. customers. We produced approximately 1.3 million tons of steam coal from this mine for the year ended December 31, 2018. We believe the possibility exists to expand production up to 2.0 million tons per year with further development of the mine at the Pennyrile complex.

Other Non-Mining Operations

In addition to our mining operations, we operate various subsidiaries which provide auxiliary services for our coal mining operations. Rhino Services is responsible for mine-related construction, site and roadway maintenance and post-mining reclamation. Through Rhino Services, we plan and monitor each phase of our mining projects as well as the post-mining reclamation efforts. We also perform the majority of our drilling and blasting activities at our company-operated surface mines in-house rather than contracting to a third party.

Other Natural Resource Assets

Oil and Natural Gas

In addition to our coal operations, we have invested in oil and natural gas assets and operations.

In December 2012, we made an initial investment in a new joint venture, Muskie Proppant LLC ("Muskie"), with affiliates of Wexford Capital. In November 2014, we contributed our investment interest in Muskie to Mammoth Energy Partners LP ("Mammoth") in return for a limited partner interest in Mammoth. In October 2016, we contributed our limited partner interests in Mammoth to Mammoth, Inc. in exchange for 234,300 shares of common stock of Mammoth, Inc.

In September 2014, we made an initial investment of $5.0 million in a new joint venture, Sturgeon Acquisitions LLC ("Sturgeon"), with affiliates of Wexford Capital and Gulfport Energy Corporation (NASDAQ: GPOR) ("Gulfport"). We accounted for the investment in this joint venture and results of operations under the equity method based upon our ownership percentage. We recorded our proportionate share of the operating income for this investment for the year ended December 31, 2017 of approximately $36,000. In June 2017, we contributed our limited partner interests in Sturgeon to Mammoth Inc. in exchange for 336,447 shares of common stock of Mammoth Inc. As of December 31, 2018, we owned 104,100 shares of Mammoth Inc.

As of December 31, 2018 and 2017, we recorded our investment in Mammoth Inc. as a current asset, which was classified as available-for-sale. We have included our investment in Mammoth Inc. in the Other category for segment reporting purposes.

Coal Customers

General

Our primary customers for our steam coal are electric utilities and industrial consumers, and the metallurgical coal we produce is sold primarily to domestic and international steel producers and coal brokers. For the year ended December 31, 2018, approximately 81.0% of our coal sales tons consisted of steam coal and approximately 19.0% consisted of metallurgical coal. For the year ended December 31, 2018, approximately 40.0% of our coal sales tons that we produced were sold to electric utilities. The majority of our electric utility customers purchase coal for terms of one to three years, but we also supply coal on a spot basis for some of our customers. For the year ended December 31, 2018, we derived approximately 80.0% of our total coal revenues from sales to our ten largest customers, with affiliates of our top three customers accounting for approximately 40.4% of our coal revenues for that period.

Coal Supply Contracts

For the years ended December 31, 2018 and 2017, approximately 64% and 59%, respectively, of our aggregate coal tons sold were sold through supply contracts. We expect to continue selling a significant portion of our coal under supply contracts. As of December 31, 2018, we had commitments under supply contracts to deliver annually scheduled base quantities as follows:

Year	Tons (in thousands)	Number of customers
2019	3,699	18
2020	1,979	6
2021	352	2

Some of the contracts have sales price adjustment provisions, subject to certain limitations and adjustments, based on a variety of factors and indices.

Quality and volumes for the coal are stipulated in coal supply contracts, and in some instances buyers have the option to vary annual or monthly volumes. Most of our coal supply contracts contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content, sulfur, ash, hardness and ash fusion temperature. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts. Some of our contracts specify approved locations from which coal may be sourced. Some of our contracts set out mechanisms for temporary reductions or delays in coal volumes in the event of a force majeure, including events such as strikes, adverse mining conditions, mine closures, or serious transportation problems that affect us or unanticipated plant outages that may affect the buyers.

The terms of our coal supply contracts result from competitive bidding procedures and extensive negotiations with customers. As a result, the terms of these contracts, including price adjustment features, price re-opener terms, coal quality requirements, quantity parameters, permitted sources of supply, future regulatory changes, extension options, force majeure, termination and assignment provisions, vary significantly by customer.

Transportation

We ship coal to our customers by rail, truck or barge. A significant portion of our coal is transported to customers by either the CSX Railroad or the Norfolk Southern Railroad in eastern Kentucky and by the Ohio Central Railroad or the Wheeling & Lake Erie Railroad in Ohio. We use third-party trucking to transport coal to our customers in Utah. For our Pennyrile complex in western Kentucky, coal is transported to our customers via barge from our river loadout on the Green River located on our Pennyrile mining complex. In addition, coal from certain of our Central Appalachia mines is located within economical trucking distance to the Big Sandy River and can be transported by barge. It is customary for customers to pay the transportation costs to their location.

We believe that we have good relationships with rail carriers, barge companies and truck companies due, in part, to our modern coal-loading facilities at our loadouts and the working relationships and experience of our transportation and distribution employees.

Suppliers

Principal supplies used in our business include diesel fuel, explosives, maintenance and repair parts and services, roof control and support items, tires, conveyance structures, ventilation supplies and lubricants. We use third-party suppliers for a significant portion of our equipment rebuilds and repairs and construction.

We have a centralized sourcing group for major supplier contract negotiation and administration, for the negotiation and purchase of major capital goods and to support the mining and coal preparation plants. We are not dependent on any one supplier in any region. We promote competition between suppliers and seek to develop relationships with those suppliers whose focus is on lowering our costs. We seek suppliers who identify and concentrate on implementing continuous improvement opportunities within their area of expertise.

Competition

The coal industry is highly competitive. There are numerous large and small producers in all coal producing regions of the United States and we compete with many of these producers. Our main competitors include Alliance Resource Partners LP, Alpha Natural Resources, Inc., Arch Coal, Inc., Booth Energy Group, Blackhawk Mining, LLC, Murray Energy Corporation, Foresight Energy LP, and Wolverine Fuels, LLC.

The most important factors on which we compete are coal price, coal quality and characteristics, transportation costs and the reliability of supply. Demand for coal and the prices that we will be able to obtain for our coal are closely linked to coal consumption patterns of the domestic electric generation industry and international consumers. These coal consumption patterns are influenced by factors beyond our control, including demand for electricity, which is significantly dependent upon economic activity and summer and winter temperatures in the United States, government regulation, technological developments and the location, availability, quality and price of competing sources of fuel such as natural gas, oil and nuclear, and alternative energy sources such as hydroelectric power, solar power and wind power.

Regulation and Laws

Our operations are subject to regulation by federal, state and local authorities on matters such as:

- employee health and safety;
- governmental approvals and other authorizations such as mine permits, as well as other licensing requirements;
- air quality standards;
- water quality standards;
- storage, treatment, use and disposal of petroleum products and other hazardous substances;
- plant and wildlife protection;
- reclamation and restoration of mining properties after mining is completed;
- the discharge of materials into the environment, including waterways or wetlands;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining;
- the effects, if any, that mining has on groundwater quality and availability; and
- legislatively mandated benefits for current and retired coal miners.

In addition, many of our customers are subject to extensive regulation regarding the environmental impacts associated with the combustion or other use of coal, which could affect demand for our coal. The possibility exists that new laws or regulations, or new interpretations of existing laws or regulations, may be adopted that may have a significant impact on our mining operations or our customers' ability to use coal. Moreover, environmental citizen groups frequently challenge coal mining, terminal construction, and other related projects.

We are committed to conducting mining operations in compliance with applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time. Violations, including violations of any permit or approval, can result in substantial civil and in severe cases, criminal fines and penalties, including revocation or suspension of mining permits. None of the violations to date have had a material impact on our operations or financial condition.

While it is not possible to quantify the costs of compliance with applicable federal and state laws and regulations, those costs have been and are expected to continue to be significant. Nonetheless, capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value of estimated cost of reclamation and mine closings, including the cost of treating mine water discharge when necessary. The accruals for reclamation and mine closing costs are based upon permit requirements and the costs and timing of reclamation and mine closing procedures. Although management believes it has made adequate provisions for all expected reclamation and other costs associated with mine closures, future operating results would be adversely affected if we later determined these accruals to be insufficient. Compliance with these laws and regulations has substantially increased the cost of coal mining for all domestic coal producers.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for coal mining operations. When we apply for these permits and approvals, we are often required to assess the effect or impact that any proposed production of coal may have upon the environment. The permit application requirements may be costly and time consuming, and may delay or prevent commencement or continuation of mining operations in certain locations. In addition, these permits and approvals can result in the imposition of numerous restrictions on the time, place and manner in which coal mining operations are conducted. Future laws and regulations may emphasize more heavily the protection of the environment and, as a consequence, our activities may be more closely regulated. Laws and regulations, as well as future interpretations or enforcement of existing laws and regulations, may require substantial increases in equipment and operating costs, or delays, interruptions or terminations of operations, the extent of any of which cannot be predicted. In addition, the permitting process for certain mining operations can extend over several years, and can be subject to judicial challenge, including by the public. Some required mining permits are becoming increasingly difficult to obtain in a timely manner, or at all. We may experience difficulty and/or delay in obtaining mining permits in the future.

Regulations provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations which have outstanding environmental violations. Although, like other coal companies, we have been cited for violations in the ordinary course of business, we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

Before commencing mining on a particular property, we must obtain mining permits and approvals by state regulatory authorities of a reclamation plan for restoring, upon the completion of mining, the mined property to its approximate prior condition, productive use or other permitted condition.

Mine Health and Safety Laws

Stringent safety and health standards have been in effect since the adoption of the Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 (the “Mine Act”), and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards and imposed comprehensive safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. The Mine Safety and Health Administration (“MSHA”) monitors compliance with these laws and regulations. In addition, the states where we operate also have state programs for mine safety and health regulation and enforcement. Federal and state safety and health regulations affecting the coal industry are complex, rigorous and comprehensive, and have a significant effect on our operating costs.

The Mine Act is a strict liability statute that requires mandatory inspections of surface and underground coal mines and requires the issuance of enforcement action when it is believed that a standard has been violated. A penalty is required to be imposed for each cited violation. Negligence and gravity assessments result in a cumulative enforcement scheme that may result in the issuance of an order requiring the immediate withdrawal of miners from the mine or shutting down a mine or any section of a mine or any piece of mine equipment. The Mine Act contains criminal liability provisions. For example, criminal liability may be imposed for corporate operators who knowingly or willfully authorize, order or carry out violations. The Mine Act also provides that civil and criminal penalties may be assessed against individual agents, officers and directors who knowingly authorize, order or carry out violations.

We have developed a health and safety management system that, among other things, includes training regarding worker health and safety requirements including those arising under federal and state laws that apply to our mines. In addition, our health and safety management system tracks the performance of each operational facility in meeting the requirements of safety laws and company safety policies. As an example of the resources we allocate to health and safety matters, our safety management system includes a company-wide safety director and local safety directors who oversee safety and compliance at operations on a day-to-day basis. We continually monitor the performance of our safety management system and from time-to-time modify that system to address findings or reflect new requirements or for other reasons. We have even integrated safety matters into our compensation and retention decisions. For instance, our bonus program includes a meaningful evaluation of each eligible employee’s role in complying with, fostering and furthering our safety policies.

We evaluate a variety of safety-related metrics to assess the adequacy and performance of our safety management system. For example, we monitor and track performance in areas such as "accidents, reportable accidents, lost time accidents and the lost-time accident frequency rate" and a number of others. Each of these metrics provides insights and perspectives into various aspects of our safety systems and performance at particular locations or mines generally and, among other things, can indicate where improvements are needed or further evaluation is warranted with regard to the system or its implementation. An important part of this evaluation is to assess our performance relative to certain national benchmarks.

For the year ended December 31, 2018 our average MSHA violations per inspection day was 0.39 as compared to the most recent national average of 0.59 violations per inspection day for coal mining activity as reported by MSHA, or 33.89% below this national average.

Mining accidents in the last several years in West Virginia, Kentucky and Utah have received national attention and instigated responses at the state and national levels that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. For example, in 2014, MSHA adopted a final rule to lower miners' exposure to respirable coal mine dust. The rule had a phased implementation schedule. The second phase of the rule went into effect in February 2016, and requires increased sampling frequency and the use of continuous personal dust monitors. In August 2016, the third and final phase of the rule became effective, reducing the overall respirable dust standard in coal mines from 2.0 to 1.5 milligrams per cubic meter of air. Additionally, in September 2015, MSHA issued a proposed rule requiring the installation of proximity detection systems on coal hauling machines and scoops. Proximity detection is a technology that uses electronic sensors to detect motion and the distance between a miner and a machine. These systems provide audible and visual warnings, and automatically stop moving machines when miners are in the machines' path. These and other new safety rules could result in increased compliance costs on our operations.

In addition, more stringent mine safety laws and regulations promulgated by the states and the federal government have included increased sanctions for non-compliance. For example, in 2006, the Mine Improvement and New Emergency Response Act of 2006, or MINER Act, was enacted. The MINER Act significantly amended the Mine Act, requiring improvements in mine safety practices, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection and enforcement activities. Since passage of the MINER Act in 2006, enforcement scrutiny has increased, including more inspection hours at mine sites, increased numbers of inspections and increased issuance of the number and the severity of enforcement actions and related penalties. For example, in July 2014, MSHA proposed a rule that revises its civil penalty assessment provisions and how regulators should approach calculating penalties, which, in some instances, could result in increased civil penalty assessments for medium and larger mine operators and contractors by 300 to 1,000 percent. MSHA proposed some revisions to the original proposed rule in February 2015, but, to date, has not taken any further action. Other states have proposed or passed similar bills, resolutions or regulations addressing enhanced mine safety practices and increased fines and penalties. Moreover, workplace accidents, such as the April 5, 2010, Upper Big Branch Mine incident, have resulted in more inspection hours at mine sites, increased number of inspections and increased issuance of the number and severity of enforcement actions and the passage of new laws and regulations. These trends are likely to continue.

In 2013, MSHA began implementing its Pattern of Violation ("POV") regulations under the Mine Act. Under this regulation, MSHA eliminated the ninety (90) day window to take corrective action and engage in mitigation efforts for mine operators who met certain initial POV screening criteria. Additionally, MSHA will make POV determinations based upon enforcement actions as issued, rather than enforcement actions that have been rendered final following the opportunity for administrative or judicial review. After a mine operator has been placed on POV status, MSHA will thereafter issue an order withdrawing miners from the area affected by any enforcement action designated by MSHA as posing a significant and substantial, or S&S, hazard to the health and/or safety of miners. Further, once designated as a POV mine, a mine operator can be removed from POV status only upon: (1) a complete inspection of the entire mine with no S&S enforcement actions issued by MSHA; or (2) no POV-related withdrawal orders being issued by MSHA within ninety (90) days of the mine operator being placed on POV status. Although it remains to be seen how these new regulations will ultimately affect production at our mines, they are consistent with the trend of more stringent enforcement.

From time to time, certain portions of individual mines have been required to suspend or shut down operations temporarily in order to address a compliance requirement or because of an accident. For instance, MSHA issues orders pursuant to Section 103(k) that, among other things, call for operations in the area of the mine at issue to suspend operations until compliance is restored. Likewise, if an accident occurs within a mine, the MSHA requirements call for all operations in that area to be suspended until the circumstance leading to the accident has been resolved. During the fiscal year ended December 31, 2018 (as in earlier years), we received such orders from government agencies and have experienced accidents within our mines requiring the suspension or shutdown of operations in those particular areas until the circumstances leading to the accident have been resolved. While the violations or other circumstances that caused such an accident were being addressed, other areas of the mine could and did remain operational. These circumstances did not require us to suspend operations on a mine-wide level or otherwise entail material financial or operational consequences for us. Any suspension of operations at any one of our locations that may occur in the future may have material financial or operational consequences for us.

It is our practice to contest notices of violations in cases in which we believe we have a good faith defense to the alleged violation or the proposed penalty and/or other legitimate grounds to challenge the alleged violation or the proposed penalty. We exercise substantial efforts toward achieving compliance at our mines. For example, we have further increased our focus with regard to health and safety at all of our mines. These efforts include hiring additional skilled personnel, providing training programs, hosting quarterly safety meetings with MSHA personnel and making capital expenditures in consultation with MSHA aimed at increasing mine safety. We believe that these efforts have contributed, and continue to contribute, positively to safety and compliance at our mines. In “Part 1, Item 4. Mine Safety Disclosure” and in Exhibit 95.1 to this Annual Report on Form 10-K, we provide additional details on how we monitor safety performance and MSHA compliance, as well as provide the mine safety disclosures required pursuant to Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Black Lung Laws

Under the Black Lung Benefits Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, coal mine operators must make payments of black lung benefits to current and former coal miners with black lung disease, some survivors of a miner who dies from this disease, and to fund a trust fund for the payment of benefits and medical expenses to claimants who last worked in the industry prior to January 1, 1970. To help fund these benefits, a tax is levied on production of $0.50 per ton for underground-mined coal and $0.25 per ton for surface-mined coal, but not to exceed 2.0% of the applicable sales price (rates effective January 1, 2019). This excise tax does not apply to coal that is exported outside of the United States. In 2018, we recorded approximately $2.5 million of expense related to this excise tax.

The Patient Protection and Affordable Care Act includes significant changes to the federal black lung program including an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes could have a material impact on our costs expended in association with the federal black lung program. We may also be liable under state laws for black lung claims that are covered through either insurance policies or state programs.

Workers’ Compensation

We are required to compensate employees for work-related injuries under various state workers’ compensation laws. The states in which we operate consider changes in workers’ compensation laws from time to time. Our costs will vary based on the number of accidents that occur at our mines and other facilities, and our costs of addressing these claims. We are insured under the Ohio State Workers Compensation Program for our operations in Ohio. Our remaining operations, including Central Appalachia, the Illinois Basin and the Western Bituminous region, are insured through Rockwood Casualty Insurance Company.

Surface Mining Control and Reclamation Act ("SMCRA")

SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining, including the surface effects of underground coal mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities. In conjunction with mining the property, we reclaim and restore the mined areas by grading, shaping and preparing the soil for seeding. Upon completion of mining, reclamation generally is completed by seeding with grasses or planting trees for a variety of uses, as specified in the approved reclamation plan. We believe we are in compliance in all material respects with applicable regulations relating to reclamation.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. The act requires that we restore the surface to approximate the original contours as soon as practicable upon the completion of surface mining operations. The mine operator must submit a bond or otherwise secure the performance of these reclamation obligations. Mine operators can also be responsible for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of long-wall mining and possibly other mining operations. In addition, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed prior to SMCRA's adoption in 1977. The maximum tax for the period from October 1, 2012 through September 30, 2021, has been decreased to 28 cents per ton on surface mined coal and 12 cents per ton on underground mined coal. However, this fee is subject to change. Should this fee be increased in the future, given the market for coal, it is unlikely that coal mining companies would be able to recover all of these fees from their customers. As of December 31, 2018, we had accrued approximately $18.5 million for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation of orphaned mine sites and abandoned mine drainage control on a statewide basis.

After a mine application is submitted, public notice or advertisement of the proposed permit action is required, which is followed by a public comment period. It is not uncommon for a SMCRA mine permit application to take over two years to prepare and review, depending on the size and complexity of the mine, and another two years or even longer for the permit to be issued. The variability in time frame required to prepare the application and issue the permit can be attributed primarily to the various regulatory authorities' discretion in the handling of comments and objections relating to the project received from the general public and other agencies. Also, it is not uncommon for a permit to be delayed as a result of judicial challenges related to the specific permit or another related company's permit.

Federal laws and regulations also provide that a mining permit or modification can be delayed, refused or revoked if owners of specific percentages of ownership interests or controllers (i.e., officers and directors or other entities) of the applicant have, or are affiliated with another entity that has outstanding violations of SMCRA or state or tribal programs authorized by SMCRA. This condition is often referred to as being "permit blocked" under the federal Applicant Violator Systems, or AVS. Thus, non-compliance with SMCRA can provide the basis to deny the issuance of new mining permits or modifications of existing mining permits, although we know of no basis by which we would be (and we are not now) permit-blocked.

In addition, a February 2014 decision by the U.S. District Court for the District of Columbia invalidated the Office of Surface Mining Reclamation and Enforcement's ("OSM") 2008 Stream Buffer Zone Rule, which prohibited mining disturbances within 100 feet of streams, subject to various exemptions. In December 2016, the OSM published the final Stream Protection Rule, which, among other things, would have required operators to test and monitor conditions of streams they might impact before, during and after mining. The final rule took effect in January 2017 and would have required mine operators to collect additional baseline data about the site of the proposed mining operation and adjacent areas; imposed additional surface and groundwater monitoring requirements; enacted specific requirements for the protection or restoration of perennial and intermittent streams; and imposed additional bonding and financial assurance requirements. However, in February 2017, the rule was revoked pursuant to the Congressional Review Act. Accordingly, the rule "shall have no force or effect" and OSM cannot promulgate a substantially similar rule absent future legislation. Whether Congress will enact future legislation to require a new Stream Protection Rule remains uncertain. A new Stream Protection Rule, or other new SMCRA regulations, could result in additional material costs, obligations, and restrictions associated with our operations.

Surety Bonds

Federal and state laws require a mine operator to secure the performance of its reclamation obligations required under SMCRA through the use of surety bonds or other approved forms of performance security to cover the costs the state would incur if the mine operator were unable to fulfill its obligations. It has become increasingly difficult for mining companies to secure new surety bonds without the posting of partial collateral. In August 2016, the OSMRE issued a Policy Advisory discouraging state regulatory authorities from approving self-bonding arrangements. The Policy Advisory indicated that the OSM would begin more closely reviewing instances in which states accept self-bonds for mining operations. In the same month, the OSM also announced that it was beginning the rulemaking process to strengthen regulations on self-bonding. In addition, surety bond costs have increased while the market terms of surety bond have generally become less favorable. It is possible that surety bond issuers may refuse to renew bonds or may demand additional collateral upon those renewals. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on our ability to produce coal, which could affect our profitability and cash flow.

As of December 31, 2018, we had approximately $42.6 million in surety bonds outstanding to secure the performance of our reclamation obligations. Of the $42.6 million, approximately $0.4 million relates to surety bonds for Deane Mining, LLC and approximately $3.4 million relates to surety bonds for Sands Hill Mining, LLC, which in each case have not been transferred or replaced by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC as was agreed to by the parties as part of the transactions. We can provide no assurances that a surety company will underwrite the surety bonds of the purchasers of these entities, nor are we aware of the actual amount of reclamation at any given time. Further, if there was a claim under these surety bonds prior to the transfer or replacement of such bonds by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC, then we may be responsible to the surety company for any amounts it pays in respect of such claim. While the buyers are required to indemnify us for damages, including reclamation liabilities, pursuant the agreements governing the sales of these entities, we may not be successful in obtaining any indemnity or any amounts received may be inadequate.

Air Emissions

The federal Clean Air Act (the “CAA”) and similar state and local laws and regulations, which regulate emissions into the air, affect coal mining operations both directly and indirectly. The CAA directly impacts our 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 CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants and other industrial consumers of coal, including air emissions of sulfur dioxide, nitrogen oxides, particulates, mercury and other compounds. There have been a series of recent federal rulemakings from the U.S. Environmental Protection Agency, or EPA, which are focused on emissions from coal-fired electric generating facilities. For example, in June 2015, the United States Supreme Court decided Michigan v. the EPA, which held that the EPA should have considered the compliance costs associated with its Mercury and Air Toxics Standards, or MATS, in deciding to regulate power plants under Section 112(n)(1) of the Clean Air Act. The Court did not vacate the MATS rule, and MATS has remained in place. In April 2016, EPA published its final supplemental finding that it is “appropriate and necessary” to regulate coal and oil-fired units under Section 112 of the Clean Air Act. That finding was challenged in court, but the rule remained in effect. In April 2017, the D.C. Circuit agreed to EPA’s request to delay proceedings while the EPA reviewed the supplemental finding to determine whether it should be maintained, modified, or otherwise reconsidered. In December 2018, the EPA issued a proposed revised Supplemental Cost Finding for the MATS rule proposing to determine that it is not “appropriate and necessary” to regulate Hazardous Air Pollutant (“HAP”) emissions from power plants under Section 112 of the Clean Air Act. The EPA did not propose, however, to rescind or repeal the HAP emission standards and other requirements of the MATS rule, which would remain in place under the proposal. Installation of additional emissions control technology and additional measures required under laws and regulations related to air emissions will make it more costly to operate coal-fired power plants and possibly other facilities that consume coal and, depending on the requirements of individual state implementation plans, or SIPs, could make coal a less attractive fuel alternative in the planning and building of power plants in the future.

In addition to the greenhouse gas ("GHG") regulations discussed below, air emission control programs that affect our operations, directly or indirectly, through impacts to coal-fired utilities and other manufacturing plants, include, but are not limited to, the following:

- The EPA's Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility's sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or "scrubbers," or by reducing electricity generating levels.

- On July 6, 2011, the EPA finalized the Cross State Air Pollution Rule ("CSAPR"), which requires the District of Columbia and 27 states from Texas eastward (not including the New England states or Delaware) to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. In September 2016, EPA finalized the CSAPR Rule Update for the 2008 ozone national air quality standards ("NAAQS"). The rule aims to reduce summertime NOx emissions from power plants in 22 states in the eastern United States. Consolidated judicial challenges to the rule are now pending in the D.C. Circuit Court of Appeals.

- In addition, in January 2013, the EPA issued final MACT standards for several classes of boilers and process heaters, including large coal-fired boilers and process heaters (Boiler MACT), which require significant reductions in the emission of particulate matter, carbon monoxide, hydrogen chloride, dioxins and mercury. Various legal challenges were filed and EPA promulgated a revised final rule in November 2015. In December 2016, the D.C. Circuit remanded the Boiler MACT standards to the EPA requiring the agency to revise emissions standards for certain boiler subcategories. The court determined that the existing MACT standards should remain in place while the revised standards are being developed, but did not establish a deadline for the EPA to complete the rulemaking. In June 2017, the U.S. Supreme Court declined to review the D.C. Circuit ruling. We cannot predict the outcome of any legal challenges that may be filed in the future. Before reconsideration, the EPA estimated that the rule would affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. Some owners will make capital expenditures to retrofit boilers and process heaters, while a number of boilers and process heaters will be prematurely retired. The retirements are likely to reduce the demand for coal. The impact of the regulations will depend on the outcome of future legal challenges and EPA actions that cannot be determined at this time.

- The EPA has adopted new, more stringent NAAQS for ozone, fine particulate matter, nitrogen dioxide and sulfur dioxide. As a result, some states will be required to amend their existing SIPs to attain and maintain compliance with the new air quality standards. For example, in June 2010, the EPA issued a final rule setting forth a more stringent primary NAAQS applicable to sulfur dioxide. The rule also modifies the monitoring increment for the sulfur dioxide standard, establishing a 1-hour standard, and expands the sulfur dioxide monitoring network. Initial non-attainment determinations related to the 2010 sulfur dioxide rule were published in August 2013 with an effective date in October 2013. States with non-attainment areas had to submit their SIP revisions in April 2015, which must meet the modified standard by summer 2017. For all other areas, states will be required to submit "maintenance" SIPs. EPA finalized its PM2.5 NAAQS designations in December 2014. Individual states must now identify the sources of PM2.5 emissions and develop emission reduction plans, which may be state-specific or regional in scope. Nonattainment areas must meet the revised standard no later than 2021. More recently, in October 2015, the EPA lowered the NAAQS for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. Significant additional emissions control expenditures will likely be required at coal-fired power plants and coke plants to meet the new standards. The EPA completed area designations for the 2015 ozone standards in July 2018. Because coal mining operations and coal-fired electric generating facilities emit particulate matter and sulfur dioxide, our mining operations and customers could be affected when the standards are implemented by the applicable states. Moreover, we could face adverse impacts on our business to the extent that these and any other new rules affecting coal-fired power plants result in reduced demand for coal.

- In June 2005, the EPA amended its regional haze program to improve visibility in national parks and wilderness areas. Affected states were required to develop SIPs by December 2007 that, among other things, were to identify facilities that would have to reduce emissions and comply with stricter emission limitations. The vast majority of states failed to submit their plans by the December 2017 deadline. The EPA ultimately agreed in a consent decree with environmental groups to impose regional haze federal implementation plans or to take action on regional haze SIPs before the agency for 42 states and the District of Columbia. The EPA has completed those actions for all but several states in its first planning period (2008-2010). The continued implementation of this program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas and may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide, and particulate matter. Consequently, demand for our steam coal could be affected. However, in January 2018 EPA announced that it was revisiting the 2017 Regional Haze Rule revisions, and announced an intent to commence a new rulemaking. In September 2018, EPA released the Regional Haze Reform Roadmap directing EPA staff to take certain actions to ensure adequate support for states to enable timely and effective implementation of the regional haze program and announcing EPA's intent to issue new guidance and continue exploring further regulatory changes. Accordingly, future implementation of these rules is unclear.

In addition, over the years, the Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the new source review provisions of the CAA. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for our coal could be affected.

Non-government organizations have also petitioned EPA to regulate coal mines as stationary sources under the Clean Air Act. On May 13, 2014, the D.C. Circuit in WildEarth Guardians v. United States Environmental Protection Agency upheld EPA's denial of one such petition. On July 18, 2014, the D.C. Circuit denied a petition to rehear that case en banc. We cannot guarantee that these groups will not make similar efforts in the future. If such efforts are successful, emissions of these or other materials associated with our mining operations could become subject to further regulation pursuant to existing laws such as the CAA. In that event, we may be required to install additional emissions control equipment or take other steps to lower emissions associated with our operations, thereby reducing our revenues and adversely affecting our operations.

Climate Change

One by-product of burning coal is carbon dioxide or CO_2, which EPA considers a GHG and a major source of concern with respect to climate change and global warming.

On the international level, the United States was one of almost 200 nations that agreed on December 12, 2015 to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emission targets and be transparent about the measures each country will use to achieve its GHG emission targets; however, the agreement does not set binding GHG emission reduction targets. The Paris climate agreement entered into force in November 2016; however, in August 2017 the U.S. State Department officially informed the United Nations of the intent of the U.S. to withdraw from the agreement, with the earliest possible effective date of withdrawal being November 4, 2020. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. These commitments could further reduce demand and prices for coal.

At the Federal level, EPA has taken a number of steps to regulate GHG emissions. For example, in August 2015, the EPA issued its final Clean Power Plan (the "CPP") rules that establish carbon pollution standards for power plants, called CO_2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay of the implementation of the CPP in February 2016. By its terms, this stay will remain in effect throughout the pendency of the appeals process. The Supreme Court's stay applies only to EPA's regulations for CO_2 emissions from existing power plants and will not affect EPA's standards for new power plants. It is not yet clear how the courts will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with the proposed repeal, EPA issued an Advance Notice of Proposed Rulemaking ("ANPRM") in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. In August 2018, the EPA issued the proposed Affordable Clean Energy ("ACE") Rule, which would replace the CPP. If the ACE Rule is finalized, it will likely be subject to judicial challenge. If the effort to repeal the CPP is unsuccessful and the rules were upheld at the conclusion of the appellate process and were implemented in their current form or if the ACE Rule results in state plans to reduce the level of GHG emissions from electric utility generating units, demand for coal will likely be further decreased. The EPA also issued a final rule for new coal-fired power plants in August 2015, which essentially set performance standards for coal-fired power plants that requires partial carbon capture and sequestration ("CCS"). Additional legal challenges have been filed against the EPA's rules for new power plants. The EPA's GHG rules for new and existing power plants, taken together, have the potential to severely reduce demand for coal. In addition, passage of any comprehensive federal climate change and energy legislation could impact the demand for coal. Any reduction in the amount of coal consumed by North American electric power generators could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

Many states and regions have adopted greenhouse gas initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of greenhouse gases by certain facilities, including coal-fired electric generating facilities. For example, in 2005, ten northeastern states entered into the Regional Greenhouse Gas Initiative agreement ("RGGI") calling for implementation of a cap and trade program aimed at reducing carbon dioxide emissions from power plants in the participating states. The members of RGGI have established in statute and/or regulation a carbon dioxide trading program. Auctions for carbon dioxide allowances under the program began in September 2008. Though New Jersey withdrew from RGGI in 2011, since its inception, several additional northeastern states and Canadian provinces have joined as participants or observers.

Following the RGGI model, five Western states launched the Western Regional Climate Action Initiative to identify, evaluate and implement collective and cooperative methods of reducing greenhouse gases in the region to 15% below 2005 levels by 2020. These states were joined by two additional states and four Canadian provinces and became collectively known as the Western Climate Initiative Partners. However, in November 2011, six states withdrew, leaving California and the four Canadian provinces as members. At a January 12, 2012 stakeholder meeting, this group confirmed a commitment and timetable to create the largest carbon market in North America and provide a model to guide future efforts to establish national approaches in both Canada and the U.S. to reduce GHG emissions. It is likely that these regional efforts will continue.

Many coal-fired plants have already closed or announced plans to close and proposed new construction projects have also come under additional scrutiny with respect to GHG emissions. There have been an increasing number of protests and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators due to concerns related to greenhouse gas emissions. Other state regulatory authorities have also rejected the construction of new coal-fueled power plants based on the uncertainty surrounding the potential costs associated with GHG emissions from these plants under future laws limiting the emissions of carbon dioxide. In addition, several permits issued to new coal-fired power plants without limits on GHG emissions have been appealed to the EPA's Environmental Appeals Board. In addition, over 30 states have adopted mandatory "renewable portfolio standards," which require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect our current and prospective customers, they may reduce the demand for coal-fired power, and may affect long-term demand for our coal.

If mandatory restrictions on CO_2 emissions are imposed, the ability to capture and store large volumes of carbon dioxide emissions from coal-fired power plants may be a key mitigation technology to achieve emissions reductions while meeting projected energy demands. A number of recent legislative and regulatory initiatives to encourage the development and use of carbon capture and storage technology have been proposed or enacted. For example, in October 2015, the EPA released a rule that established, for the first time, new source performance standards under the federal Clean Air Act for CO_2 emissions from new fossil fuel-fired electric utility generating power plants. The EPA has designated partial carbon capture and sequestration as the best system of emission reduction for newly constructed fossil fuel-fired steam generating units at power plants to employ to meet the standard. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available at economically competitive prices and supportive national policy frameworks are in place.

There have also been attempts to encourage greater regulation of coalbed methane because methane has a greater GHG effect than CO2. Methane from coal mines can give rise to safety concerns, and may require that various measures be taken to mitigate those risks. If new laws or regulations were introduced to reduce coalbed methane emissions, those rules could adversely affect our costs of operations.

These and other current or future global climate change laws, regulations, court orders or other legally enforceable mechanisms, or related public perceptions regarding climate change, are expected to require additional controls on coal-fired power plants and industrial boilers and may cause some users of coal to further switch from coal to alternative sources of fuel, thereby depressing demand and pricing for coal.

Finally, some scientists have warned that increasing concentrations of greenhouse gases ("GHGs") in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If these warnings are correct, and if any such effects were to occur in areas where we or our customers operate, they could have an adverse effect on our assets and operations.

Clean Water Act

The Federal Clean Water Act (the "CWA") and similar state and local laws and regulations affect coal mining operations by imposing restrictions on the discharge of pollutants, including dredged or fill material, into waters of the U.S. The CWA establishes in-stream water quality and treatment standards for wastewater discharges that are applied to wastewater dischargers through Section 402 National Pollutant Discharge Elimination System ("NPDES") permits. Regular monitoring, as well as compliance with reporting requirements and performance standards, are preconditions for the issuance and renewal of Section 402 NPDES permits. Individual permits or general permits under Section 404 of the CWA are required to discharge dredged or fill materials into waters of the U.S. including wetlands, streams, and other areas meeting the regulatory definition. Expansion of EPA jurisdiction over these areas has the potential to adversely impact our operations. Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the Clean Water Act. A 2015 rulemaking by EPA to revise the standard was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit and stayed for certain primarily western states by a United States District Court in North Dakota. In January 2018, the Supreme Court determined that the circuit courts do not have jurisdiction to hear challenges to the 2015 rule, removing the basis for the Sixth Circuit to continue its nationwide stay. In February 2018, the EPA and the U.S. Army Corps of Engineers (the "Corps") published a final rule extending the applicability date of the 2015 rule such that the rule would not be applicable until February 2020. In August 2018, the U.S. District Court for the District of South Carolina invalidated the two-year nationwide delay of the rule, leaving the 2015 rule in effect in 26 states, while the pre-2015 regulations and guidance continue to apply in 24 states. In December 2018, the EPA and the Corps proposed a new definition of "waters of the United States." Judicial challenges to the 2015 rulemaking are likely to continue to work their way through the courts along with challenges to the more recent rulemaking extending the applicability date of the 2015 rule. The agencies' efforts to repeal the 2015 rule and to revise the definition of "waters of the United States" will also likely be subject to lengthy judicial challenges. For now, EPA and the Corps are complying with the South Carolina District Court's order in the 26 states in which it applies. Should the 2015 rule be enforced in the states in which we operate, or should a different rule expanding the definition of what constitutes a water of the United States be finalized as a result of EPA and the Corps's rulemaking process, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

Our surface coal mining and preparation plant operations typically require such permits to authorize activities such as the creation of slurry ponds, stream impoundments, and valley fills. The EPA, or a state that has been delegated such authority by the EPA, issues NPDES permits for the discharge of pollutants into navigable waters, while the U.S. Army Corps of Engineers (the "Corps") issues dredge and fill permits under Section 404 of the CWA. Where Section 402 NPDES permitting authority has been delegated to a state, the EPA retains a limited oversight role. The CWA also gives the EPA an oversight role in the Section 404 permitting program, including drafting substantive rules governing permit issuance by the Corps, providing comments on proposed permits, and, in some cases, exercising the authority to delay or pre-empt Corps issuance of a Section 404 permit. The EPA has recently asserted these authorities more forcefully to question, delay, and prevent issuance of some Section 402 and 404 permits for surface coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

For instance, even though the Commonwealth of Kentucky and the State of West Virginia have been delegated the authority to issue NPDES permits for coal mines in those states, the EPA is taking a more active role in its review of NPDES permit applications for coal mining operations in Appalachia. The EPA issued final guidance on July 21, 2011 that encouraged EPA Regions 3, 4 and 5 to object to the issuance of state program NPDES permits where the Region does not believe that the proposed permit satisfies the requirements of the CWA and with regard to state issued general Section 404 permits, support the previously drafted Enhanced Coordination Process ("ECP") among the EPA, the Corps, and the U.S. Department of the Interior for issuing Section 404 permits, whereby the EPA undertook a greater level of review of certain Section 404 permits than it had previously undertaken. The D.C. Circuit upheld EPA's use of the ECP in July 2014. Future application of the ECP, such as may be enacted following notice and comment rulemaking, would have the potential to delay issuance of permits for surface coal mines, or to change the conditions or restrictions imposed in those permits.

The EPA also has statutory "veto" power under Section 404(c) to effectively revoke a previously issued Section 404 permit if the EPA determines, after notice and an opportunity for a public hearing, that the permit will have an "unacceptable adverse effect." The Court previously upheld the EPA's ability to exercise this authority. Any future use of the EPA's Section 404 "veto" power could create uncertainty with regard to our continued use of their current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting our revenues.

The Corps is authorized to issue general "nationwide" permits for specific categories of activities that are similar in nature and that are determined to have minimal adverse environmental effects. We may no longer seek general permits under Nationwide Permit 21 ("NWP 21") because in February 2012, the Corps reinstated the use of NWP 21, but limited application of NWP 21 authorizations to discharges with impacts not greater than a half-acre of water, including no more than 300 linear feet of streambed, and disallowed the use of NWP 21 for valley fills. This limitation remains in place in the NWP 21 issued in January of 2017. If the 2017 NWP 21 cannot be used for any of our proposed surface coal mining projects, we will have to obtain individual permits from the Corps subject to the additional EPA measures discussed below with the uncertainties and delays attendant to that process.

We currently have a number of Section 404 permit applications pending with the Corps. Not all of these permit applications seek approval for valley fills or other obvious "fills"; some relate to other activities, such as mining through streams and the associated post-mining reconstruction efforts. We sought to prepare all pending permit applications consistent with the requirements of the Section 404 program. Our five year plan of mining operations does not rely on the issuance of these pending permit applications. However, the Section 404 permitting requirements are complex, and regulatory scrutiny of these applications, particularly in Appalachia, has increased such that our applications may not be granted or, alternatively, the Corps may require material changes to our proposed operations before it grants permits. While we will continue to pursue the issuance of these permits in the ordinary course of our operations, to the extent that the permitting process creates significant delay or limits our ability to pursue certain reserves beyond our current five year plan, our revenues may be negatively affected.

Total Maximum Daily Load ("TMDL") regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired water body can receive and still meet state water quality standards, and to allocate pollutant loads among the point- and non-point pollutant sources discharging into that water body. Likewise, when water quality in a receiving stream is better than required, states are required to conduct an anti-degradation review before approving discharge permits. The adoption of new TMDLs and load allocations or any changes to anti-degradation policies for streams near our coal mines could limit our ability to obtain NPDES permits, require more costly water treatment, and adversely affect our coal production.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Some products used by coal companies in operations generate waste containing hazardous substances. We are not aware of any material liability associated with the release or disposal of hazardous substances from our past or present mine sites.

The federal Resource Conservation and Recovery Act ("RCRA") and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous wastes. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, such costs are not believed to have a material impact on our operations.

In December 2014, EPA finalized regulations that address the management of coal ash as a non-hazardous solid waste under Subtitle D. The rules impose engineering, structural and siting standards on surface impoundments and landfills that hold coal combustion wastes and mandate regular inspections. The rule also requires fugitive dust controls and imposes various monitoring, cleanup, and closure requirements. The rule leaves intact the Bevill exemption for beneficial uses of CCB, though it defers a final Bevill regulatory determination with respect to CCB that is disposed of in landfills or surface impoundments. Additionally, in December 2016, Congress passed the Water Infrastructure Improvements for the Nation Act, which provides for the establishment of state and EPA permit programs for the control of coal combustion residuals and authorizes states to incorporate EPA's final rule for coal combustion residuals or develop other criteria that are at least as protective as the final rule. The costs of complying with these new requirements may result in a material adverse effect on our business, financial condition or results of operations, and could potentially increase our customers' operating costs, thereby reducing their ability to purchase coal as a result. In addition, contamination caused by the past disposal of CCB, including coal ash, can lead to material liability to our customers under RCRA or other federal or state laws and potentially reduce the demand for coal.

Endangered Species Act

The federal Endangered Species Act and counterpart state legislation protect species threatened with possible extinction. Protection of threatened and endangered species may have the effect of prohibiting or delaying us from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species or their habitats. A number of species indigenous to our properties are protected under the Endangered Species Act. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our ability to mine coal from our properties in accordance with current mining plans.

Use of Explosives

We use explosives in connection with our surface mining activities. The Federal Safe Explosives Act ("SEA") applies to all users of explosives. Knowing or willful violations of the SEA may result in fines, imprisonment, or both. In addition, violations of SEA may result in revocation of user permits and seizure or forfeiture of explosive materials.

The storage of explosives is also subject to regulatory requirements. For example, pursuant to a rule issued by the Department of Homeland Security in 2007, facilities in possession of chemicals of interest (including ammonium nitrate at certain threshold levels) are required to complete a screening review in order to help determine whether there is a high level of security risk, such that a security vulnerability assessment and a site security plan will be required. It is possible that our use of explosives in connection with blasting operations may subject us to the Department of Homeland Security's chemical facility security regulatory program. The costs of compliance with these requirements should not have a material adverse effect on our business, financial condition or results of operations.

In December 2014, OSM announced its decision to propose a rule that will address all blast generated fumes and toxic gases. OSM has not yet issued a proposed rule to address these blasts. We are unable to predict the impact, if any, of these actions by the OSM, although the actions potentially could result in additional delays and costs associated with our blasting operations.

Other Environmental and Mine Safety Laws

We are required to comply with numerous other federal, state and local environmental and mine safety laws and regulations in addition to those previously discussed. These additional laws include, for example, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right-to-Know Act. The costs of compliance with these requirements is not expected to have a material adverse effect on our business, financial condition or results of operations.

Federal Power Act – Grid Reliability Proposal

Pursuant to a direction from the Secretary of the Department of Energy, the Federal Energy Regulatory Commission ("FERC") issued a notice of proposed rulemaking under the Federal Power Act regarding the valuation by regional electric grid system operators of the reliability and resilience attributes of electricity generation. The rulemaking would have required the FERC to impose market rules that would allow certain cost recovery by electricity-generating units that maintain a 90-day fuel supply on-site and that are therefore capable of providing electricity during supply disruptions from emergencies, extreme weather or natural or man-made disasters. Many coal-fired electricity generating plants could have qualified under this criteria and the cost recovery could have helped improve the economics of their operations. However, in January 2018, the FERC terminated the proposed rulemaking, finding that it failed to satisfy the legal requirements of section 206 of the Federal Power Act, and initiated a new proceeding to further evaluate whether additional FERC action regarding resilience is appropriate. Should a version of this rule be adopted in the future along the lines originally proposed, it could provide economic incentives for companies that produce electricity from coal, among other fuels, which could either slow or stabilize the trend in the shuttering of coal-fired power plants and could thereby maintain certain levels of domestic demand for coal. We cannot speculate on the timing or nature of any subsequent FERC or grid operator actions resulting from the FERC's decision to further study the issue of grid resiliency.

Employees

To carry out our operations, our general partner and our subsidiaries employed 701 full-time employees as of December 31, 2018. None of the employees are subject to collective bargaining agreements. We believe that we have good relations with these employees and since our inception we have had no history of work stoppages or union organizing campaigns.

Available Information

Our internet address is *http://www.rhinolp.com*, and we make available free of charge on our website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and Forms 3, 4 and 5 for our Section 16 filers (and amendments and exhibits, such as press releases, to such filings) as soon as reasonably practicable after we electronically file with or furnish such material to the SEC. Also included on our website are our "Code of Business Conduct and Ethics", our "Insider Trading Policy," "Whistleblower Policy" and our "Corporate Governance Guidelines" adopted by the board of directors of our general partner and the charters for the Audit Committee and Compensation Committee. Information on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

We file or furnish annual, quarterly and current reports and other documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). The SEC's website, *http://www.sec.gov,* contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC.

Item 1A. Risk Factors.

In addition to the factors discussed elsewhere in this report, including the financial statements and related notes, you should consider carefully the risks and uncertainties described below. If any of these risks or uncertainties, as well as other risks and uncertainties that are not currently known to us or that we currently believe are not material, were to occur, our business, financial condition or results of operation could be materially adversely affected and you may lose all or a significant part of your investment.

Risks Inherent in Our Business

Our common units are currently traded on the OTCQB as a result of the NYSE's delisting our common units and will trade indefinitely on the OTCQB or one of the other over-the-counter markets, which could adversely affect the market liquidity of our common units and harm our business.

Our common units were suspended from trading on the NYSE at the close of trading on December 17, 2015 and delisted from the NYSE on May 9, 2016. Our common units trade on the OTCQB under the ticker symbol "RHNO." The common units will continue to trade on the OTCQB or one of the other over-the-counter markets.

Trading on the OTCQB or one of the other over-the-counter markets may result in a reduction in some or all of the following, each of which could have a material adverse effect on our unitholders:

- the liquidity of our common units;
- the market price of our common units;
- our ability to issue additional securities or obtain financing;
- the number of institutional and other investors that will consider investing in our common units;
- the number of market makers in our common units;
- the availability of information concerning the trading prices and volume of our common units; and
- the number of broker-dealers willing to execute trades in our common units.

Further, since our common units were delisted from the NYSE, we are no longer subject to the NYSE rules including rules requiring us to meet certain corporate governance standards. Without required compliance of these corporate governance standards, investor interest in our common units may decrease.

We may not have sufficient cash to enable us to pay the minimum quarterly distribution on our common units following establishment of cash reserves and payment of costs and expenses, including reimbursement of expenses to our general partner.

We may not have sufficient cash each quarter to pay the full amount of our minimum quarterly distribution of $4.45 per unit, or $17.80 per unit per year, which will require us to have available cash of approximately $58.6 million per quarter, or $234.2 million per year, based on the number of common and subordinated units outstanding as of December 31, 2018 and the general partner interest. The amount of cash we can distribute on our common and subordinated units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of coal we are able to produce from our properties, which could be adversely affected by, among other things, operating difficulties and unfavorable geologic conditions;
- the price at which we are able to sell coal, which is affected by the supply of and demand for domestic and foreign coal;

- the level of our operating costs, including reimbursement of expenses to our general partner and its affiliates. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed;

- the proximity to and capacity of transportation facilities;

- the price and availability of alternative fuels;

- the impact of future environmental and climate change regulations, including those impacting coal-fired power plants;

- the level of worldwide energy and steel consumption;

- prevailing economic and market conditions;

- difficulties in collecting our receivables because of credit or financial problems of customers;

- the effects of new or expanded health and safety regulations;

- domestic and foreign governmental regulation, including changes in governmental regulation of the mining industry, the electric utility industry or the steel industry;

- changes in tax laws;

- weather conditions; and

- force majeure.

We may reduce or eliminate distributions at any time we determine that our cash reserves are insufficient or are otherwise required to fund current or anticipated future operations, capital expenditures, acquisitions, growth or expansion projects, debt repayment or other business needs. Beginning with the quarter ended September 30, 2014, distributions on our common units were below the minimum level and, beginning with the quarter ended June 30, 2015, we suspended the quarterly distribution on our common units altogether. Pursuant to our partnership agreement, our common units accrue arrearages every quarter when the distribution level is below the minimum quarterly distribution level and our subordinated units do not accrue such arrearages. In the future, if and as distributions are made for any quarter, the first priority is to pay the then minimum quarterly distribution to common unitholders. Any additional distribution amounts paid at that time are then paid to common unitholders until previously unpaid accumulated arrearage amounts have been paid in full. Thus, we have arrearages accumulating on our common units since the distribution level has been below our minimum quarterly level of $4.45 per unit. In addition, we have not paid any distributions on our subordinated units for any quarter after the quarter ended March 31, 2012. We may not have sufficient cash available for distributions on our common or subordinated units in the future. Any further reduction in the amount of cash available for distributions could impact our ability to pay any quarterly distribution on our common units. Moreover, we may not be able to increase distributions on our common units if we are unable to pay the accumulated arrearages on our common units as well as the full minimum quarterly distribution on our subordinated units.

A decline in coal prices could adversely affect our results of operations and cash available for distribution to our unitholders.

Our results of operations and the value of our coal reserves are significantly dependent upon the prices we receive for our coal as well as our ability to improve productivity and control costs. Prices for coal tend to be cyclical. The prices we receive for coal depend upon factors beyond our control, including:

- the supply of domestic and foreign coal;

- the demand for domestic and foreign coal, which is significantly affected by the level of consumption of steam coal by electric utilities and the level of consumption of metallurgical coal by steel producers;
- the price and availability of alternative fuels for electricity generation;
- the proximity to, and capacity of, transportation facilities;
- domestic and foreign governmental regulations, particularly those relating to the environment, climate change, health and safety;
- the level of domestic and foreign taxes;
- weather conditions;
- terrorist attacks and the global and domestic repercussions from terrorist activities; and
- prevailing economic conditions.

Any adverse change in these factors could result in weaker demand and lower prices for our products. In addition, global financial and credit market disruptions have historically had an impact on the coal industry generally and may continue to do so. The demand for electricity and steel may decline if economic conditions weaken. If electricity and steel demand weaken, we may not be able to sell all of the coal we are capable of producing or sell our coal at acceptable prices.

In addition to competing with other coal producers, we compete generally with producers of other fuels, such as natural gas. A decline in the price of natural gas has made natural gas more competitive against coal and resulted in utilities switching from coal to natural gas. Sustained low natural gas prices may also cause utilities to phase out or close existing coal-fired power plants or reduce or eliminate construction of any new coal-fired power plants, which could have a material adverse effect on demand and prices received for our coal. A substantial or extended decline in the prices we receive for our coal supply contracts could materially and adversely affect our results of operations.

We performed a comprehensive review of our coal mining operation as well as potential future development projects for the year ended December 31, 2018 to ascertain any potential impairment losses. We did not record any impairment losses for coal properties, mine development costs or coal mining equipment and related facilities for the year ended December 31, 2018.

We performed a comprehensive review of our current coal mining operation as well as potential future development projects for the year ended December 31, 2017 to ascertain any potential impairment losses. We engaged an independent third party to perform a fair market value appraisal on certain parcels of land that we own in Mesa County, Colorado. The parcels appraised for $6.0 million compared to the carrying value of $6.8 million. We recorded an impairment loss of $0.8 million, which is recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income. No other coal properties, mine development costs or other coal mining equipment and related facilities were impaired as of December 31, 2017.

We also recorded an impairment charge of $21.8 million related to the call option received from a third party to acquire substantially all of the outstanding common stock of Armstrong Energy, Inc. On October 31, 2017, Armstrong Energy filed Chapter 11 petitions in the Eastern District of Missouri's United States Bankruptcy Court. Per the Chapter 11 petitions, Armstrong Energy filed a detailed restructuring plan as part of the Chapter 11 proceedings. On February 9, 2018, the U.S. Bankruptcy Court confirmed Armstrong Energy's Chapter 11 reorganization plan and as such we concluded that the call option had no carrying value. An impairment charge of $21.8 million related to the call option was recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income.

We could be negatively impacted by the competitiveness of the global markets in which we compete and declines in the market demand for coal.

We compete with coal producers in various regions of the United States and overseas for domestic and international sales. The domestic demand for, and prices of, our coal primarily depend on coal consumption patterns of the domestic electric utility industry and the domestic steel industry. Consumption by the domestic electric utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel sources, such as natural gas, nuclear, hydroelectric, solar and wind power and other renewable energy sources. Consumption by the domestic steel industry is primarily affected by economic growth and the demand for steel used in construction as well as appliances and automobiles. The competitive environment for coal is impacted by a number of the largest markets in the world, including the United States, China, Japan and India, where demand for both electricity and steel has supported prices for steam and metallurgical coal. The economic stability of these markets has a significant effect on the demand for coal and the level of competition in supplying these markets. The cost of ocean transportation and the value of the U.S. dollar in relation to foreign currencies significantly impact the relative attractiveness of our coal as we compete on price with foreign coal producing sources. During the last several years, the U.S. coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. Increased competition by coal producers or producers of alternate fuels could decrease the demand for, or pricing of, or both, for our coal, adversely impacting our results of operations and cash available for distribution.

Any change in consumption patterns by utilities away from the use of coal, such as resulting from current low natural gas prices, could affect our ability to sell the coal we produce, which could adversely affect our results of operations and cash available for distribution to our unitholders.

Steam coal accounted for approximately 81% of our coal sales volume for the year ended December 31, 2018. The majority of our sales of steam coal during this period were to electric utilities for use primarily as fuel for domestic electricity consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and oil as well as alternative sources of energy. We compete generally with producers of other fuels, such as natural gas and oil. A decline in price for these fuels could cause demand for coal to decrease and adversely affect the price of our coal. For example, sustained low natural gas prices have led, in some instances, to decreased coal consumption by electricity-generating utilities. If alternative energy sources, such as nuclear, hydroelectric, wind or solar, become more cost-competitive on an overall basis, demand for coal could decrease and the price of coal could be materially and adversely affected. Further, legislation requiring, subsidizing or providing tax benefits for the use of alternative energy sources and fuels, or legislation providing financing or incentives to encourage continuing technological advances in this area, could further enable alternative energy sources to become more competitive with coal. A decrease in coal consumption by the domestic electric utility industry could adversely affect the price of coal, which could materially adversely affect our results of operations and cash available for distribution to our unitholders.

Numerous political and regulatory authorities, along with environmental activist groups, are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation, domestically and internationally, thereby further reducing the demand and pricing for coal, and potentially materially and adversely impacting our future financial results, liquidity and growth prospects.

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, unfavorable lending policies by government-backed lending institutions and development banks toward the financing of new overseas coal-fueled power plants and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities. Global climate issues continue to attract public and scientific attention. Numerous reports, such as the Fourth and Fifth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In turn, increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions of carbon dioxide from coal combustion by power plants. The 2015 Paris climate summit agreement resulted in voluntary commitments by numerous countries to reduce their GHG emissions, and could result in additional firm commitments by various nations with respect to future GHG emissions. These commitments could further disfavor coal-fired generation, particularly in the medium- to long-term.

Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the United States, some of its states or other countries, or other actions to limit such emissions, could also result in electricity generators further switching from coal to other fuel sources or additional coal-fueled power plant closures. Further, policies limiting available financing for the development of new coal-fueled power plants could adversely impact the global demand for coal in the future.

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 fuel reserves. In California, for example, legislation was signed into law in October 2015 that requires California's state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining by July 2017. More recently, in December 2017, the Governor of New York announced that the New York Common Fund will immediately cease all new investments in entities with "significant fossil fuel activities," and the World Bank announced that it will no longer finance upstream oil and gas after 2019, except in "exceptional circumstances." Other activist campaigns have urged banks to cease financing coal-driven businesses. As a result, numerous major banks have enacted such policies. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

In addition, several well-funded non-governmental organizations have explicitly undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation. For example, the goals of Sierra Club's "Beyond Coal" campaign include retiring one-third of the nation's coal-fired power plants by 2020, replacing retired coal plants with "clean energy solutions," and "keeping coal in the ground."

The net effect of these developments is to make it more costly and difficult to maintain our business and to continue to depress demand and pricing for our coal. A substantial or extended decline in the prices we receive for our coal due to these or other factors could further reduce our revenue and profitability, cash flows, liquidity, and value of our coal reserves and result in losses.

Our mining operations are subject to extensive and costly environmental laws and regulations, and such current and future laws and regulations could materially increase our operating costs or limit our ability to produce and sell coal.

The coal mining industry is subject to numerous and extensive federal, state and local environmental laws and regulations, including laws and regulations pertaining to permitting and licensing requirements, air quality standards, plant and wildlife protection, reclamation and restoration of mining properties, the discharge of materials into the environment, the storage, treatment and disposal of wastes, protection of wetlands, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. The costs, liabilities and requirements associated with these laws and regulations are significant and time-consuming and may delay commencement or continuation of our operations. Moreover, the possibility exists that new laws or regulations (or new judicial interpretations or enforcement policies of existing laws and regulations) could materially affect our mining operations, results of operations and cash available for distribution to our unitholders, either through direct impacts such as those regulating our existing mining operations, or indirect impacts such as those that discourage or limit our customers' use of coal. Violations of applicable laws and regulations would subject us to administrative, civil and criminal penalties and a range of other possible sanctions. The enforcement of laws and regulations governing the coal mining industry has increased substantially. As a result, the consequences for any noncompliance may become more significant in the future.

Our operations use petroleum products, coal processing chemicals and other materials that may be considered "hazardous materials" under applicable environmental laws and have the potential to generate other materials, all of which may affect runoff or drainage water. In the event of environmental contamination or a release of these materials, we could become subject to claims for toxic torts, natural resource damages and other damages and for the investigation and cleanup of soil, surface water, groundwater, and other media, as well as abandoned and closed mines located on property we operate. Such claims may arise out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire.

The government extensively regulates mining operations, especially with respect to mine safety and health, which imposes significant actual and potential costs on us, and future regulation could increase those costs or limit our ability to produce coal.

Coal mining is subject to inherent risks to safety and health. As a result, the coal mining industry is subject to stringent safety and health standards. Fatal mining accidents in the United States have received national attention and have led to responses at the state and federal levels that have resulted in increased regulatory scrutiny of coal mining operations, particularly underground mining operations. More stringent state and federal mine safety laws and regulations have included increased sanctions for non-compliance. Moreover, future workplace accidents are likely to result in more stringent enforcement and possibly the passage of new laws and regulations.

Within the last few years, the industry has seen enactment of the Federal Mine Improvement and New Emergency Response Act of 2006 (the "MINER Act"), subsequent additional legislation and regulation imposing significant new safety initiatives and the Dodd-Frank Act, which, among other things, imposes new mine safety information reporting requirements. The MINER Act significantly amended the Federal Mine Safety and Health Act of 1977 (the "Mine Act"), imposing more extensive and stringent compliance standards, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection, and enforcement activities. Following the passage of the MINER Act, the U.S. Mine Safety and Health Administration ("MSHA") issued new or more stringent rules and policies on a variety of topics, including:

- sealing off abandoned areas of underground coal mines;
- mine safety equipment, training and emergency reporting requirements;
- substantially increased civil penalties for regulatory violations;
- training and availability of mine rescue teams;
- underground "refuge alternatives" capable of sustaining trapped miners in the event of an emergency;
- flame-resistant conveyor belt, fire prevention and detection, and use of air from the belt entry; and
- post-accident two-way communications and electronic tracking systems.

For example, in 2014, MSHA adopted a final rule that reduces the permissible concentration of respirable dust in underground coal mines from the current standard of 2.0 milligrams per cubic meter of air to 1.5 milligram per cubic meter. The rule had a phased implementation schedule, and the third and final phase of the rule became effective in August 2016. Under the phased approach, operators were required to adopt new measures and procedures for dust sampling, record keeping, and medical surveillance. Additionally, in September 2015, MSHA issued a proposed rule that would require underground coal mine operators to equip coal hauling machines and scoops on working sections with proximity detection systems. Proximity detection is a technology that uses electronic sensors to detect motion and the distance between a miner and a machine. These systems provide audible and visual warnings, and automatically stop moving machines when miners are in the machines' path. These and other new safety rules could result in increased compliance costs on our operations. Subsequent to passage of the MINER Act, various coal producing states, including West Virginia, Ohio and Kentucky, have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight. Other states may pass similar legislation in the future. Additional federal and state legislation that would further increase mine safety regulation, inspection and enforcement, particularly with respect to underground mining operations, has also been considered.

Although we are unable to quantify the full impact, implementing and complying with these new laws and regulations could have an adverse impact on our results of operations and cash available for distribution to our unitholders and could result in harsher sanctions in the event of any violations. Please read "Part 1, Item 1. Business—Regulation and Laws."

Penalties, fines or sanctions levied by MSHA could have a material adverse effect on our business, results of operations and cash available for distribution.

Surface and underground mines like ours and those of our competitors are continuously inspected by MSHA, which often leads to notices of violation. Recently, MSHA has been conducting more frequent and more comprehensive inspections. In addition, in July 2014, MSHA proposed a rule that revises its civil penalty assessment provisions and how regulators should approach calculating penalties, which, in some instances, could result in increased civil penalty assessments for medium and larger mine operators and contractors by 300% to 1,000%. MSHA issued a revised proposed rule in February 2015, but, to date, has not taken any further action. However, increased scrutiny by MSHA and enforcement against mining operations are likely to continue.

We have in the past, and may in the future, be subject to fines, penalties or sanctions resulting from alleged violations of MSHA regulations. Any of our mines could be subject to a temporary or extended shut down as a result of an alleged MSHA violation. Any future penalties, fines or sanctions could have a material adverse effect on our business, results of operations and cash available for distribution.

We may be unable to obtain and/or renew permits necessary for our operations, which could prevent us from mining certain reserves.

Numerous governmental permits and approvals are required for mining operations, and we can face delays, challenges to, and difficulties in acquiring, maintaining or renewing necessary permits and approvals, including environmental permits. The permitting rules, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by regulators, all of which may make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing mining operations or the development of future mining operations. In addition, the public has certain statutory rights to comment upon and otherwise impact the permitting process, including through court intervention. Over the past few years, the length of time needed to bring a new surface mine into production has increased because of the increased time required to obtain necessary permits. The slowing pace at which permits are issued or renewed for new and existing mines has materially impacted production in Appalachia, but could also affect other regions in the future.

Section 402 National Pollutant Discharge Elimination System permits and Section 404 CWA permits are required to discharge wastewater and discharge dredged or fill material into waters of the United States (“WOTUS”). Expansion of EPA jurisdiction over these areas has the potential to adversely impact our operations. Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the Clean Water Act. Please read “Part I, Item 1. Business—Regulation and Laws—Clean Water Act.” Currently, 26 states are subject to the 2015 rule, while the pre-2015 regulations and guidance continue to apply in 24 states. Should the 2015 rule be enforced in the states in which we operate, or should a different rule expanding the definition of what constitutes a water of the United States be finalized as a result of EPA and the Corps’s rulemaking process, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Our surface coal mining operations typically require such permits to authorize such activities as the creation of slurry ponds, stream impoundments, and valley fills. Although the CWA gives the EPA a limited oversight role in the Section 404 permitting program, the EPA has recently asserted its authorities more forcefully to question, delay, and prevent issuance of some Section 404 permits for surface coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

Our mining operations are subject to operating risks that could adversely affect production levels and operating costs.

Our mining operations are subject to conditions and events beyond our control that could disrupt operations, resulting in decreased production levels and increased costs.

These risks include:

- unfavorable geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposit;

- inability to acquire or maintain necessary permits or mining or surface rights;
- changes in governmental regulation of the mining industry or the electric utility industry;
- adverse weather conditions and natural disasters;
- accidental mine water flooding;
- labor-related interruptions;
- transportation delays;
- mining and processing equipment unavailability and failures and unexpected maintenance problems; and
- accidents, including fire and explosions from methane.

Any of these conditions may increase the cost of mining and delay or halt production at particular mines for varying lengths of time, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

In general, mining accidents present a risk of various potential liabilities depending on the nature of the accident, the location, the proximity of employees or other persons to the accident scene and a range of other factors. Possible liabilities arising from a mining accident include workmen's compensation claims or civil lawsuits for workplace injuries, claims for personal injury or property damage by people living or working nearby and fines and penalties including possible criminal enforcement against us and certain of our employees. In addition, a significant accident that results in a mine shut-down could give rise to liabilities for failure to meet the requirements of coal supply agreements especially if the counterparties dispute our invocation of the force majeure provisions of those agreements. We maintain insurance coverage to mitigate the risks of certain of these liabilities, including business interruption insurance, but those policies are subject to various exclusions and limitations and we cannot assure you that we will receive coverage under those policies for any personal injury, property damage or business interruption claims that may arise out of such an accident. Moreover, certain potential liabilities such as fines and penalties are not insurable risks. Thus, a serious mine accident may result in material liabilities that adversely affect our results of operations and cash available for distribution.

Fluctuations in transportation costs or disruptions in transportation services could increase competition or impair our ability to supply coal to our customers, which could adversely affect our results of operations and cash available for distribution to our unitholders.

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer's purchasing decision. Increases in transportation costs could make coal a less competitive energy source or could make our coal production less competitive than coal produced from other sources.

Significant decreases in transportation costs could result in increased competition from coal producers in other regions. For instance, coordination of the many eastern U.S. coal loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make shipments originating in the eastern United States inherently more expensive on a per-mile basis than shipments originating in the western United States. Historically, high coal transportation rates from the western coal producing regions limited the use of western coal in certain eastern markets. The increased competition could have an adverse effect on our results of operations and cash available for distribution to our unitholders.

We depend primarily upon railroads, barges and trucks to deliver coal to our customers. Disruption of any of these services due to weather-related problems, strikes, lockouts, accidents, mechanical difficulties and other events could temporarily impair our ability to supply coal to our customers, which could adversely affect our results of operations and cash available for distribution to our unitholders.

In recent years, the states of Kentucky and West Virginia have increased enforcement of weight limits on coal trucks on their public roads. It is possible that other states may modify their laws to limit truck weight limits. Such legislation and enforcement efforts could result in shipment delays and increased costs. An increase in transportation costs could have an adverse effect on our ability to increase or to maintain production and could adversely affect our results of operations and cash available for distribution.

A shortage of skilled labor in the mining industry could reduce productivity and increase operating costs, which could adversely affect our results of operations and cash available for distribution to our unitholders.

Efficient coal mining using modern techniques and equipment requires skilled laborers. During periods of high demand for coal, the coal industry has experienced a shortage of skilled labor as well as rising labor and benefit costs, due in large part to demographic changes as existing miners retire at a faster rate than new miners are entering the workforce. If a shortage of experienced labor should occur or coal producers are unable to train enough skilled laborers, there could be an adverse impact on labor productivity, an increase in our costs and our ability to expand production may be limited. If coal prices decrease or our labor prices increase, our results of operations and cash available for distribution to our unitholders could be adversely affected.

Unexpected increases in raw material costs, such as steel, diesel fuel and explosives could adversely affect our results of operations.

Our coal mining operations are affected by commodity prices. We use significant amounts of steel, diesel fuel, explosives and other raw materials in our mining operations, and volatility in the prices for these raw materials could have a material adverse effect on our operations. Steel prices and the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel fluctuate significantly and may change unexpectedly. Additionally, a limited number of suppliers exist for explosives, and any of these suppliers may divert their products to other industries. Shortages in raw materials used in the manufacturing of explosives, which, in some cases, do not have ready substitutes, or the cancellation of supply contracts under which these raw materials are obtained, could increase the prices and limit the ability of us or our contractors to obtain these supplies. Future volatility in the price of steel, diesel fuel, explosives or other raw materials will impact our operating expenses and could adversely affect our results of operations and cash available for distribution.

If we are not able to acquire replacement coal reserves that are economically recoverable, our results of operations and cash available for distribution to our unitholders could be adversely affected.

Our results of operations and cash available for distribution to our unitholders depend substantially on obtaining coal reserves that have geological characteristics that enable them to be mined at competitive costs and to meet the coal quality needed by our customers. Because we deplete our reserves as we mine coal, our future success and growth will depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. If we fail to acquire or develop additional reserves, our existing reserves will eventually be depleted. Replacement reserves may not be available when required or, if available, may not be capable of being mined at costs comparable to those characteristic of the depleting mines. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our results of operations and cash available for distribution to our unitholders. Exhaustion of reserves at particular mines with certain valuable coal characteristics also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

Inaccuracies in our estimates of coal reserves and non-reserve coal deposits could result in lower than expected revenues and higher than expected costs.

We base our coal reserve and non-reserve coal deposit estimates on engineering, economic and geological data assembled and analyzed by our staff, which is periodically audited by independent engineering firms. These estimates are also based on the expected cost of production and projected sale prices and assumptions concerning the permitability and advances in mining technology. The estimates of coal reserves and non-reserve coal deposits as to both quantity and quality are periodically updated to reflect the production of coal from the reserves, updated geologic models and mining recovery data, recently acquired coal reserves and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating quantities and qualities of coal reserves and non-reserve coal deposits and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves necessarily depend upon a number of variable factors and assumptions, all of which may vary considerably from actual results. These factors and assumptions relate to:

- quality of coal;
- geological and mining conditions and/or effects from prior mining that may not be fully identified by available exploration data or which may differ from our experience in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;
- historical production from the area compared with production from other similar producing areas;
- the timing for the development of reserves; and
- assumptions concerning equipment and productivity, future coal prices, operating costs, capital expenditures and development and reclamation costs.

For these reasons, estimates of the quantities and qualities of the economically recoverable coal attributable to any particular group of properties, classifications of coal reserves and non-reserve coal deposits based on risk of recovery, estimated cost of production and estimates of net cash flows expected from particular reserves as prepared by different engineers or by the same engineers at different times may vary materially due to changes in the above factors and assumptions. Actual production from identified coal reserve and non-reserve coal deposit areas or properties and revenues and expenditures associated with our mining operations may vary materially from estimates. Accordingly, these estimates may not reflect our actual coal reserves or non-reserve coal deposits. Any inaccuracy in our estimates related to our coal reserves and non-reserve coal deposits could result in lower than expected revenues and higher than expected costs, which could have a material adverse effect on our ability to make cash distributions.

The amount of estimated maintenance capital expenditures our general partner is required to deduct from operating surplus each quarter could increase in the future, resulting in a decrease in available cash from operating surplus that could be distributed to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus each quarter estimated maintenance capital expenditures as opposed to actual maintenance capital expenditures in order to reduce disparities in operating surplus caused by fluctuating maintenance capital expenditures, such as reserve replacement costs or refurbishment or replacement of mine equipment. Our annual estimated maintenance capital expenditures for purposes of calculating operating surplus is based on our estimates of the amounts of expenditures we will be required to make in the future to maintain our long-term operating capacity. Our partnership agreement does not cap the amount of maintenance capital expenditures that our general partner may estimate. The amount of our estimated maintenance capital expenditures may be more than our actual maintenance capital expenditures, which will reduce the amount of available cash from operating surplus that we would otherwise have available for distribution to unitholders. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by the board of directors of our general partner at least once a year, with any change approved by the conflicts committee. In addition to estimated maintenance capital expenditures, reimbursement of expenses incurred by our general partner and its affiliates will reduce the amount of available cash from operating surplus that we would otherwise have available for distribution to our unitholders. Please read "—Risks Inherent in an Investment in Us—Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce cash available for distribution to our unitholders. The amount and timing of such reimbursements will be determined by our general partner."

Existing and future laws and regulations regulating the emission of sulfur dioxide and other compounds could affect coal consumers and as a result reduce the demand for our coal. A reduction in demand for our coal could adversely affect our results of operations and cash available for distribution to our unitholders.

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants and other consumers of our coal. These laws and regulations can require significant emission control expenditures, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. A certain portion of our coal has a medium to high sulfur content, which results in increased sulfur dioxide emissions when combusted and therefore the use of our coal imposes certain additional costs on customers. Accordingly, these laws and regulations may affect demand and prices for our higher sulfur coal. Please read “Part I, Item 1. Business—Regulation and Laws.”

Federal and state laws restricting the emissions of greenhouse gases could adversely affect our operations and demand for our coal.

One by-product of burning coal is CO_2, which EPA considers a GHG, and a major source of concern with respect to climate change and global warming. Global warming has garnered significant public attention, and measures have been implemented or proposed at the international, federal, state and regional levels to limit GHG emissions. Please read “Part I, Item 1. Business—Regulation and Laws—Climate Change.”

For example, on the international level, the United States was one of almost 200 nations that agreed on December 12, 2015 to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emission targets and be transparent about the measures each country will use to achieve its GHG emission targets; however, the agreement does not set binding GHG emission reduction targets. The Paris climate agreement entered into force in November 2016; however, in August 2017 the U.S. State Department officially informed the United Nations of the intent of the U.S. to withdraw from the agreement, with the earliest possible effective date of withdrawal being November 4, 2020. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. These commitments could further reduce demand and prices for coal.

At the federal level, EPA has finalized a number of rules related to GHG emissions. For example, the EPA issued its final CPP rules that establish carbon pollution standards for power plants, called CO_2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay of the implementation of the CPP in February 2016. By its terms, this stay will remain in effect throughout the pendency of the appeals process. The stay suspends the rule, including the requirement that states submit their initial plans by September 2016. The Supreme Court’s stay applies only to EPA’s regulations for CO_2 emissions from existing power plants and will not affect EPA’s standards for new power plants. It is not yet clear how the courts will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with the proposed repeal, EPA issued an Advance Notice of Proposed Rulemaking (“ANPRM”) in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. In August 2018, the EPA issued the proposed ACE Rule, which would replace the CPP. If the ACE Rule is finalized, it will likely be subject to judicial challenge. If the effort to repeal and replace the CPP is unsuccessful and the rules were upheld at the conclusion of the appellate process and were implemented in their current form, or if the ACE Rule results in state plans to reduce the level of GHG emissions from electric utility generating units, demand for coal will likely be further decreased. The EPA also issued a final rule for new coal-fired power plants in August 2015, which essentially set performance standards for coal-fired power plants that requires partial carbon capture and sequestration. Additional legal challenges have been filed against the EPA’s rules for new power plants. The EPA’s GHG rules for new and existing power plants, taken together, have the potential to severely reduce demand for coal. In addition, passage of any comprehensive federal climate change and energy legislation could impact the demand for coal. Any reduction in the amount of coal consumed by North American electric power generators could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

Many states and regions have adopted greenhouse gas initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of greenhouse gases by certain facilities, including coal-fired electric generating facilities. For example, in 2005, ten northeastern states entered into the Regional Greenhouse Gas Initiative agreement (the “RGGI”), calling for implementation of a cap and trade program aimed at reducing carbon dioxide emissions from power plants in the participating states. Following the RGGI model, several western states and Canadian provinces have confirmed a commitment and timetable to create a carbon market in North America. It is likely that these regional efforts will continue.

Many coal-fired plants have already closed or announced plans to close and proposed new construction projects have also come under additional scrutiny with respect to GHG emissions. There have been an increasing number of protests and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators due to concerns related to greenhouse gas emissions. Other state regulatory authorities have also rejected the construction of new coal-fueled power plants based on the uncertainty surrounding the potential costs associated with GHG emissions from these plants under future laws limiting the emissions of GHGs. In addition, several permits issued to new coal-fired power plants without limits on GHG emissions have been appealed to the EPA's Environmental Appeals Board. In addition, over 30 states have adopted mandatory "renewable portfolio standards," which require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect our current and prospective customers; they may reduce the demand for coal-fired power, and may affect long-term demand for our coal.

If mandatory restrictions on carbon dioxide emissions are imposed, the ability to capture and store large volumes of carbon dioxide emissions from coal-fired power plants may be a key mitigation technology to achieve emissions reductions while meeting projected energy demands. A number of recent legislative and regulatory initiatives to encourage the development and use of CCS technology have been proposed or enacted. For example, in October 2015, the EPA released a rule that established, for the first time, new source performance standards under the federal Clean Air Act for CO_2 emissions from new fossil fuel-fired electric utility generating power plants. The EPA has designated partial carbon capture and sequestration as the best system of emission reduction for newly constructed fossil fuel-fired steam generating units at power plants to employ to meet the standard. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available at economically competitive prices and supportive national policy frameworks are in place.

In the meantime, the EPA and other regulators are using existing laws, including the federal Clean Air Act, to limit emissions of carbon dioxide and other GHGs from major sources, including coal-fired power plants that may require the use of "best available control technology" or "BACT." As state permitting authorities continue to consider GHG control requirements as part of major source permitting BACT requirements, costs associated with new facility permitting and use of coal could increase substantially. A growing concern is the possibility that BACT will be determined to be the use of an alternative fuel to coal.

As a result of these current and proposed laws, regulations and trends, electricity generators may elect to switch to other fuels that generate less GHG emissions, possibly further reducing demand for our coal, which could adversely affect our results of operations and cash available for distribution to our unitholders.

Finally, some scientists have warned that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If these warnings are correct, and if any such effects were to occur in areas where we or our customers operate, they could have an adverse effect on our assets and operations.

Federal and state laws require bonds to secure our obligations to reclaim mined property. Our inability to acquire or failure to maintain, obtain or renew these surety bonds could have an adverse effect on our ability to produce coal, which could adversely affect our results of operations and cash available for distribution to our unitholders.

We are required under federal and state laws to place and maintain bonds to secure our obligations to repair and return property to its approximate original state after it has been mined (often referred to as "reclamation") and to satisfy other miscellaneous obligations. Federal and state governments could increase bonding requirements in the future. In August 2016, the OSMRE issued a Policy Advisory discouraging state regulatory authorities from approving self-bonding arrangements. The Policy Advisory indicated that the OSMRE would begin more closely reviewing instances in which states accept self-bonds for mining operations. In the same month, the OSMRE also announced that it was beginning the rulemaking process to strengthen regulations on self-bonding. Certain business transactions, such as coal leases and other obligations, may also require bonding. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including supporting letters of credit or posting cash collateral or other terms less favorable to us upon those renewals. The failure to maintain or the inability to acquire sufficient surety bonds, as required by state and federal laws, could subject us to fines and penalties as well as the loss of our mining permits. Such failure could result from a variety of factors, including:

- the lack of availability, higher expense or unreasonable terms of new surety bonds;
- the ability of current and future surety bond issuers to increase required collateral; and
- the exercise by third-party surety bond holders of their right to refuse to renew the surety bonds.

We maintain surety bonds with third parties for reclamation expenses and other miscellaneous obligations. It is possible that we may in the future have difficulty maintaining our surety bonds for mine reclamation. Due to adverse economic conditions and the volatility of the financial markets, surety bond providers may be less willing to provide us with surety bonds or maintain existing surety bonds or may demand terms that are less favorable to us than the terms we currently receive. We may have greater difficulty satisfying the liquidity requirements under our existing surety bond contracts. As of December 31, 2018, we had $42.6 million in reclamation surety bonds, secured by $3.0 million in cash collateral held by our surety bond provider. Of the $42.6 million, approximately $0.4 million relates to surety bonds for Deane Mining, LLC and approximately $3.4 million relates to surety bonds for Sands Hill Mining, LLC, which in each case have not been transferred or replaced by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC as was agreed to by the parties as part of the transactions. We can provide no assurances that a surety company will underwrite the surety bonds of the purchasers of these entities, nor are we aware of the actual amount of reclamation at any given time. Further, if there was a claim under these surety bonds prior to the transfer or replacement of such bonds by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC, then we may be responsible to the surety company for any amounts it pays in respect of such claim. While the buyers are required to indemnify us for damages, including reclamation liabilities, pursuant the agreements governing the sales of these entities, we may not be successful in obtaining any indemnity or any amounts received may be inadequate. For more information, please read "Part I, Item 1. Business— Recent Developments—Letter of Credit Facility—PNC Bank." If we do not maintain sufficient borrowing capacity or have other resources to satisfy our surety and bonding requirements, our operations and cash available for distribution to our unitholders could be adversely affected.

We depend on a few customers for a significant portion of our revenues. If a substantial portion of our supply contracts terminate or if any of these customers were to significantly reduce their purchases of coal from us, and we are unable to successfully renegotiate or replace these contracts on comparable terms, then our results of operations and cash available for distribution to our unitholders could be adversely affected.

We sell a material portion of our coal under supply contracts. As of December 31, 2018, we had sales commitments for approximately 74% of our estimated coal production (including purchased coal to supplement our production) for the year ending December 31, 2019. When our current contracts with customers expire, our customers may decide not to extend or enter into new contracts. Of our total future committed tons, under the terms of the supply contracts, we will ship 61% in 2019, 33% in 2020, and 6% in 2021. We derived approximately 80.5% of our total coal revenues from coal sales to our ten largest customers for the year ended December 31, 2018, with affiliates of our top three customers accounting for approximately 40.4% of our coal revenues during that period.

In the absence of long-term contracts, our customers may decide to purchase fewer tons of coal than in the past or on different terms, including different pricing terms. Negotiations to extend existing contracts or enter into new long-term contracts with those and other customers may not be successful, and those customers may not continue to purchase coal from us under long-term coal supply contracts or may significantly reduce their purchases of coal from us. In addition, interruption in the purchases by or operations of our principal customers could significantly affect our results of operations and cash available for distribution. Unscheduled maintenance outages at our customers' power plants and unseasonably moderate weather are examples of conditions that might cause our customers to reduce their purchases. Our mines may have difficulty identifying alternative purchasers of their coal if their existing customers suspend or terminate their purchases. For additional information relating to these contracts, please read "Part I, Item 1. Business—Customers—Coal Supply Contracts."

Certain provisions in our long-term coal supply contracts may provide limited protection during adverse economic conditions, may result in economic penalties to us or permit the customer to terminate the contract.

Price adjustment, "price re-opener" and other similar provisions in our supply contracts may reduce the protection from short-term coal price volatility traditionally provided by such contracts. Price re-opener provisions typically require the parties to agree on a new price. Failure of the parties to agree on a price under a price re-opener provision can lead to termination of the contract. Any adjustment or renegotiations leading to a significantly lower contract price could adversely affect our results of operations and cash available for distribution to our unitholders.

Coal supply contracts also typically contain force majeure provisions allowing temporary suspension of performance by us or our customers during the duration of specified events beyond the control of the affected party. Most of our coal supply contracts also contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, hardness and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts. In addition, certain of our coal supply contracts permit the customer to terminate the agreement in the event of changes in regulations affecting our industry that increase the price of coal beyond a specified limit.

Defects in title in the coal properties that we own or loss of any leasehold interests could limit our ability to mine these properties or result in significant unanticipated costs.

We conduct a significant part of our mining operations on leased properties. A title defect or the loss of any lease could adversely affect our ability to mine the associated coal reserves. Title to most of our owned and leased properties and the associated mineral rights is not usually verified until we make a commitment to develop a property, which may not occur until after we have obtained necessary permits and completed exploration of the property. In some cases, we rely on title information or representations and warranties provided by our grantors or lessors, as the case may be. Our right to mine some coal reserves would be adversely affected by defects in title or boundaries or if a lease expires. Any challenge to our title or leasehold interest could delay the exploration and development of the property and could ultimately result in the loss of some or all of our interest in the property. Mining operations from time to time may rely on a lease that we are unable to renew on terms at least as favorable, if at all. In such event, we may have to close down or significantly alter the sequence of mining operations or incur additional costs to obtain or renew such leases, which could adversely affect our future coal production. If we mine on property that we do not control, we could incur liability for such mining.

Our work force could become unionized in the future, which could adversely affect our production and labor costs and increase the risk of work stoppages.

Currently, none of our employees are represented under collective bargaining agreements. However, all of our work force may not remain union-free in the future. If some or all of our work force were to become unionized, it could adversely affect our productivity and labor costs and increase the risk of work stoppages.

If we sustain cyber-attacks or other security breaches that disrupt our operations, or that result in the unauthorized release of proprietary or confidential information, we could be exposed to significant liability, reputational harm, loss of revenue, increased costs or other risks.

We may be subject to security breaches which could result in unauthorized access to our facilities or to information we are trying to protect. Unauthorized physical access to one or more of our facilities or locations, or electronic access to our proprietary or confidential information could result in, among other things, unfavorable publicity, litigation by parties affected by such breach, disruptions to our operations, loss of customers, and financial obligations for damages related to the theft or misuse of such information, any of which could have a substantial impact on our results of operations, financial condition or cash flow.

We depend on key personnel for the success of our business.

We depend on the services of our senior management team and other key personnel, including senior management of our general partner. The loss of the services of any member of senior management or key employee could have an adverse effect on our business and reduce our ability to make distributions to our unitholders. We may not be able to locate or employ on acceptable terms qualified replacements for senior management or other key employees if their services were no longer available.

If the assumptions underlying our reclamation and mine closure obligations are materially inaccurate, we could be required to expend greater amounts than anticipated.

The Federal Surface Mining Control and Reclamation Act of 1977 and counterpart state laws and regulations establish operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of underground mining. Estimates of our total reclamation and mine closing liabilities are based upon permit requirements and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed both periodically by our management and annually by independent third-party engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. Please read “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Asset Retirement Obligations.”

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures (including acquisitions) or other purposes may be impaired or such financing may not be available on favorable terms;
- covenants contained in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- we will need a portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, distributions to unitholders and future business opportunities;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Increases in our total indebtedness would increase our total interest expense, which would in turn reduce our forecasted cash available for distribution. As of December 31, 2018 our current portion of long-term debt that will be funded from cash flows from operating activities during 2019 was approximately $2.2 million. Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying our business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms, or at all.

Our financing agreement contains operating and financial restrictions that may restrict our business and financing activities and limit our ability to pay distributions upon the occurrence of certain events.

The operating and financial restrictions and covenants in our financing agreement and any future financing agreements could restrict our ability to finance future operations or capital needs or to engage, expand or pursue our business activities. For example, our financing agreement restricts our ability to:

- incur additional indebtedness or guarantee other indebtedness;
- grant liens;

- make certain loans or investments;
- dispose of assets outside the ordinary course of business, including the issuance and sale of capital stock of our subsidiaries;
- change the line of business conducted by us or our subsidiaries;
- enter into a merger, consolidation or make acquisitions; or
- make distributions if an event of default occurs.

In addition, our payment of principal and interest on our debt will reduce cash available for distribution on our units. Our financing agreement limits our ability to pay distributions upon the occurrence of the following events, among others, which would apply to us and our subsidiaries:

- failure to pay principal, interest or any other amount when due;
- breach of the representations or warranties in the credit agreement;
- failure to comply with the covenants in the credit agreement;
- cross-default to other indebtedness;
- bankruptcy or insolvency;
- failure to have adequate resources to maintain, and obtain, operating permits as necessary to conduct our operations substantially as contemplated by the mining plans used in preparing the financial projections; and
- a change of control.

Any subsequent refinancing of our current debt or any new debt could have similar restrictions. Our ability to comply with the covenants and restrictions contained in our financing agreement may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit agreement, a significant portion of our indebtedness may become immediately due and payable, and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our credit agreement will be secured by substantially all of our assets, and if we are unable to repay our indebtedness under our financing agreement, the lenders could seek to foreclose on such assets. For more information, please read "Part I, Item 1. Business—Recent Developments—Financing Agreement."

Our business is subject to cybersecurity risks.

As is typical of modern businesses, we are reliant on the continuous and uninterrupted operation of its information technology ("IT") systems. User access of our sites and IT systems can be critical elements to our operations, as is cloud security and protection against cyber security incidents. Any IT failure pertaining to availability, access or system security could potentially result in disruption of our activities, and could adversely affect our reputation, operations or financial performance.

Potential risks to the our IT systems could include unauthorized attempts to extract business sensitive, confidential or personal information, denial of access extortion, corruption of information or disruption of business processes, or by inadvertent or intentional actions by the our employees or vendors. A cybersecurity incident resulting in a security breach or failure to identify a security threat could disrupt business and could result in the loss of sensitive, confidential information or other assets, as well as litigation, regulatory enforcement, violation of privacy or securities laws and regulations, and remediation costs, all of which could materially impact the our business or reputation.

Risks Inherent in an Investment in Us

Royal owns and controls our general partner. Our general partner has fiduciary duties to its owners, and the interests of its owners may differ significantly from, or conflict with, the interests of our public common unitholders.

Royal owns and controls our general partner. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners. Therefore, conflicts of interest may arise between its owners and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its owners over the interests of our common unitholders. These conflicts include the following situations:

- our general partner is allowed to take into account the interests of parties other than us, such as its owners, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- neither our partnership agreement nor any other agreement requires Royal to pursue a business strategy that favors us;
- our partnership agreement limits the liability of and reduces fiduciary duties owed by our general partner and also restricts the remedies available to unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any capital expenditure and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus;
- our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;
- our partnership agreement permits us to distribute up to $25.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or the incentive distribution rights;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units;

- our general partner controls the enforcement of obligations that it and its affiliates owe to us;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or the unitholders. This election may result in lower distributions to the common unitholders in certain situations.

In addition, Royal, its owners and entities in which they have an interest may compete with us. Please read "—Our sponsor, Royal and affiliates of our general partner may compete with us."

Common units held by unitholders who are not eligible citizens will be subject to redemption.

In order to comply with U.S. laws with respect to the ownership of interests in mineral leases on federal lands, we have adopted certain requirements regarding those investors who own our common units. As used in this report, an eligible citizen means a person or entity qualified to hold an interest in mineral leases on federal lands. As of the date hereof, an eligible citizen must be: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; or (3) an association of U.S. citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof. For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof. Unitholders who are not persons or entities who meet the requirements to be an eligible citizen run the risk of having their units redeemed by us at the lower of their purchase price cost or the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

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 counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its 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. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally; our cash distribution policy will significantly impair our ability to grow.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. We may, in certain circumstances, be permitted under our partnership agreement and credit agreement to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common and subordinated units.

Our partnership agreement contains provisions that modify and reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common and subordinated units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning that it believed that the decision was in the best interest of our partnership;
- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is:

  (1) approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

  (2) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

  (3) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

  (4) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (3) and (4) above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our sponsor, Royal, and affiliates of our general partner may compete with us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership interest in us. However, affiliates of our general partner, including our sponsor, Royal, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. In addition, Royal and its affiliates may compete with us for investment opportunities and may own an interest in entities that compete with us. Further, Royal and its affiliates may acquire, develop or dispose of additional coal properties or other assets in the future without any obligation to offer us the opportunity to purchase or develop any of those assets.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors and Royal. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the conflicts committee of its board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units and will retain its then-current general partner interest. The number of common units to be issued to our general partner will equal the number of common units, which would have entitled the holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which the common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by Royal, as a result of it owning our general partner, and not by our unitholders. Unlike publicly traded corporations, we do not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they cannot currently remove our general partner without its consent.

If our unitholders are dissatisfied with the performance of our general partner, they will have limited ability to remove our general partner. Unitholders are currently unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least $66^2/_3$% of all outstanding common and subordinated units voting together as a single class is required to remove our general partner. As of March 15, 2019, Royal owned an aggregate of approximately 52.9% of our common and subordinated units. Also, if our general partner is removed without cause during the subordination period and no units held by the holders of the subordinated units or their affiliates are voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. Cause is narrowly defined in our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

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, our partnership agreement does not restrict the ability of the members of our general partner to transfer their respective membership interests in our general partner to a third party. The new members of our general partner would then be in a position to replace the board of directors and executive officers of our general partner with their own designees and thereby exert significant control over the decisions taken by the board of directors and executive officers of our general partner. This effectively permits a "change of control" without the vote or consent of the unitholders.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Securities Exchange Act of 1934 (the "Exchange Act"). As of March 15, 2019, Royal owned an aggregate of approximately 49.4% of our common units and approximately 93.2% of our subordinated units.

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

Our partnership agreement does not limit the number of additional limited partner interests we may issue at any time without the approval of our unitholders. The issuance of additional common units, preferred units or other equity interests of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

The Series A 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 Series A preferred units are a new class of partnership interests that rank senior to our common units with respect to distribution rights and rights upon liquidation. We are required to pay annual distributions on the Series A preferred units in an amount equal to the greater of (i) 50% of CAM Mining free cash flow (which is defined in our partnership agreement as (i) the total revenue of the our Central Appalachia business segment, minus (ii) the cost of operations (exclusive of depreciation, depletion and amortization) for the our Central Appalachia business segment, minus (iii) an amount equal to $6.50, multiplied by the aggregate number of met coal and steam coal tons sold by us from our Central Appalachia business segment) and (ii) an amount equal to the number of outstanding Series A preferred units multiplied by $0.80. If we fail to pay the any or all of the distributions in respect of the Series A preferred units, such deficiency will accrue until paid in full and we will not be permitted to pay any distributions on our partnership interests that rank junior to the Series A preferred units, including 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.

We may convert the Series A preferred units into common units at any time on or after the time at which the amount of aggregate distributions paid in respect of each Series A preferred unit exceeds $10.00 per unit. All unconverted Series A preferred units will convert into common units on December 31, 2021. The number of common units issued in any conversion will be based on the volume-weighted average closing price of the common units for 90 days preceding the date of conversion. Accordingly, the lower the trading price of our common units over the 90 day measurement period, 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 us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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.

Holders of our Series A preferred units have substantial negative control rights.

For as long as the Series A preferred units are outstanding, we will be restricted from taking certain actions without the consent of the holders of a majority of the Series A preferred units, including: (i) the issuance of additional Series A preferred units, or securities that rank senior or equal to the Series A preferred units; (ii) the sale or transfer of CAM Mining, LLC or a material portion of its assets; (iii) the repurchase of common units, or the issuance of rights or warrants to holders of common units entitling them to purchase common units at less than fair market value; (iv) consummation of a spin off; (v) the incurrence, assumption or guaranty indebtedness for borrowed money in excess of $50.0 million except indebtedness relating to entities or assets that are acquired by the Partnership or its affiliates that is in existence at the time of such acquisition or (vi) the modification of CAM Mining’s accounting principles or the financial or operational reporting principles of the our Central Appalachia business segment, subject to certain exceptions. These consent rights effectively add a constituency to our fundamental decision-making process, and failure to obtain such consent from the Series A preferred holders could prevent us from taking an action that our management or board of directors otherwise view as prudent or necessary for our business operations or the execution of our business strategy.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets, including sales by Royal or other large holders.

As of March 15, 2019, we had 13,098,353 common units, 1,143,686 subordinated units and 1,500,000 Series A preferred units outstanding. All of the subordinated units will convert into common units on a one-for-one basis at the end of the subordination period. On March 21, 2016, we issued 6,000,000 common units to Royal in a private placement. In connection with this issuance, we entered into a registration rights agreement with Royal which grants Royal piggyback registration rights under certain circumstances with respect to these common units. In addition, under our partnership agreement, our general partner and its affiliates (including Royal) have registration rights relating to the offer and sale of any units that they hold, subject to certain limitations. Sales by Royal or other large holders of a substantial number of our common units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders’ voting rights by providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce cash available for distribution to our unitholders. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our unitholders.

While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended.

While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders. However, our partnership agreement can be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by Royal) after the subordination period has ended. As of March 15, 2019, Royal owned approximately 49.4% of the outstanding common units and 93.2% of our outstanding subordinated units.

Unitholders may have liability to repay distributions and in certain circumstances may be personally liable for our obligations.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to the purchaser of units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

It may be determined that the right, or the exercise of the right by the limited partners as a group, to (i) remove or replace our general partner, (ii) approve some amendments to our partnership agreement or (iii) take other action under our partnership agreement constitutes “participation in the control” of our business. A limited partner that participates in the control of our business within the meaning of the Delaware Act may be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for 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 become subject to entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations and current Treasury Regulations, we believe that we satisfy the qualifying income requirement and will be treated as a partnership. We have received a favorable private letter ruling from the IRS to the effect that, based on facts presented in the private letter ruling request, income from management fees, cost reimbursements and cost-sharing payments related to our management and operation of mining, production, processing, and sale of coal and from energy infrastructure support services will constitute "qualifying income" within the meaning of Section 7704 of the Internal Revenue Code of 1986 (the "Code"). We may, however, decide that it is in our best interest to be treated as a corporation for federal income tax purposes. Failing to meet the qualifying income requirement, a change in current law, or an election to be treated as a corporation, could cause us to be treated as a corporation for 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 pay state and local income tax at varying rates. Any distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions, or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our common unitholders would be substantially reduced. Therefore, treatment of us as a corporation would materially reduce the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Additionally, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. We currently own assets and conduct business in several states that impose a margin or franchise tax. In the future, we may expand our operations to other states. Imposition of a similar tax on us in jurisdictions to which we expand could substantially reduce our cash available for distribution to our common unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to additional amounts of entity level taxation for U.S. federal, state, local, or foreign income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law or interpretation on us. Changes in current state law may subject us to additional entity level taxation by individual states.

Although we monitor our level of non-qualifying income closely and attempt to manage our operations to ensure compliance with the qualifying income requirement, given the continued weak demand and low prices for met and steam coal, there is a risk that we will not be able to continue to meet the qualifying income level necessary to maintain our status as a partnership for federal income tax purposes.

As a publicly traded partnership, we may be treated as a corporation for federal income tax purposes unless 90% or more of our gross income in each year consists of certain identified types of "qualifying income." In addition to qualifying income, like many other publicly traded partnerships, we also generate ancillary income that may not constitute qualifying income. Although we monitor our level of gross income that may not constitute qualifying income closely and attempt to manage our operations to ensure compliance with the qualifying income requirement, given the continued weak demand and low prices for met and steam coal, the sale of which generates qualifying income, there is a risk that we will not be able to continue to meet the qualifying income level necessary to maintain our status as a publicly-traded partnership. To the extent we become aware that we may not generate or have not generated sufficient qualifying income with respect to a tax period, we can and would take action to preserve our treatment as a partnership for federal income tax purposes, including seeking relief from the IRS. Section 7704(e) of the Internal Revenue Code provides for the possibility of relief upon, among other things, determination by the IRS that such failure to meet the qualifying income requirement was inadvertent. However, we are unaware of examples of such relief being sought by a publicly traded partnership.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that would affect publicly traded partnerships, including 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.

Any 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 such changes could negatively impact the value of an investment in our common 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 common units.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take and it may be necessary to resort to administrative or court proceedings to sustain some or all of our positions. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest with the IRS will reduce our cash available for distribution to our common unitholders and thus will be borne indirectly by our common unitholders. We have requested and obtained a favorable private letter ruling from the IRS to the effect that, based on facts presented in the private letter ruling request, income from management fees, cost reimbursements and cost-sharing payments related to our management and operation of mining, production, processing, and sale of coal and from energy infrastructure support services will constitute "qualifying income" within the meaning of Section 7704 of the Code.

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 adjustments 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 any 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 adjustments directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former 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 and pay any resulting taxes (including applicable penalties or interest) 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. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

Our common unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our common unitholders are required to pay federal income taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not they receive cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax due with respect to that income.

We anticipate engaging in transactions to reduce our indebtedness and manage our liquidity that generate taxable income (including cancellation of indebtedness income) allocable to common unitholders, and income tax liabilities arising therefrom may exceed the value of your investment in us.

In response to current market conditions, from time to time we anticipate engaging in transactions to delever us and manage our liquidity that would result in income and gain to our common unitholders without a corresponding cash distribution. For example, we may sell assets and use the proceeds to repay existing debt or fund capital expenditures, in which case, you would be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, we may anticipate pursuing opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications and extinguishment of our existing debt that would result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our common unitholders as ordinary taxable income. Common unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed the current value of your investment in us.

Entities taxed as corporations may have net operating losses to offset COD income or may otherwise qualify for an exception to the recognition of COD income, such as the bankruptcy or insolvency exceptions. As long as we are treated as a partnership, however, these exceptions are not available to the partnership and are only available to a common unitholder if the common unitholder itself is insolvent or in bankruptcy. As a result, these exceptions generally would not apply to prevent the taxation of COD income allocated to our common unitholders. The ultimate tax effect of any such income allocations will depend on the common unitholder's individual tax position, including, for example, the availability of any suspended passive losses that may offset some portion of the allocable COD income. Common 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 common unitholder's ultimate disposition of its units. Common unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD income.

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

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

A substantial portion of the amount realized from the sale of your common units, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation recapture. Thus, you may recognize both ordinary income and capital loss from the sale of your common units if the amount realized on a sale of your common units is less than your adjusted basis in the common 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 you sell your common units, you may recognize ordinary income from our allocations of income and gain to you prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of common units.

Common 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 common units that may result in adverse tax consequences to them.

Investment in our common 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, with respect to 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. If you are a tax-exempt entity, you should consult your tax advisor before investing in our common units.

Non-U.S. common unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. common 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 you and any gain from the sale of your common 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. common unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. common unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit.

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 interest 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. If you are a non-U.S. person, you should consult your tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units actually 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 common units, we have adopted certain methods of allocating depreciation and amortization deductions that may not conform to all aspects of the Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our 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 common unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our common 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 common unit is transferred. Similarly, we generally allocate gain or loss realized on the sale or other disposition of our assets or, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction on the Allocation Date. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we could be required to change our allocation of items of income, gain, loss and deduction among our common unitholders.

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

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

We have adopted certain valuation methodologies in determining a common unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, which could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our common unitholders, we must routinely determine the fair market value of our assets. Although we may, from time to time, consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our common unitholders. It also could affect the amount of gain from our common unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our common unitholders' tax returns without the benefit of additional deductions.

Common unitholders will likely be subject to state and local taxes and return filing requirements in jurisdictions where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, common unitholders will likely be 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 they do not live in any of those jurisdictions. Our common unitholders will likely be 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, common unitholders may be subject to penalties for failure to comply with those requirements.

We currently own assets and conduct business in a number of states, most of which also impose an income tax on corporations and other entities. In addition, many of these states also impose a personal income tax on individuals, corporations or other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state and local tax returns and pay any taxes due in these jurisdictions. You should consult with your own tax advisor 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 2. Properties.

See “Part I, Item 1. Business” for information about our coal operations and other natural resource assets.

Coal Reserves and Non-Reserve Coal Deposits

We base our coal reserve and non-reserve coal deposit estimates on engineering, economic and geological data assembled and analyzed by our staff. These estimates are also based on the expected cost of production and projected sale prices and assumptions concerning the permitability and advances in mining technology. The estimates of coal reserves and non-reserve coal deposits as to both quantity and quality are periodically updated to reflect the production of coal from the reserves, updated geologic models and mining recovery data, coal reserves recently acquired and estimated costs of production and sales prices. Changes in mining methods may increase or decrease the recovery basis for a coal seam as will plant processing efficiency tests. We maintain reserve and non-reserve coal deposit information in secure computerized databases, as well as in hard copy. The ability to update and/or modify the estimates of our coal reserves and non-reserve coal deposits is restricted to a few individuals and the modifications are documented.

Periodically, we retain outside experts to independently verify our coal reserve and our non-reserve coal deposit estimates. The most recent audit by an independent engineering firm of our coal reserve and non-reserve coal deposit estimates was completed by Marshall Miller & Associates, Inc. as of December 31, 2018, and covered a majority of the coal reserves and non-reserve coal deposits that we controlled as of such date. We intend to continue to periodically retain outside experts to assist management with the verification of our estimates of our coal reserves and non-reserve coal deposits going forward.

We have a geographically diverse asset base with coal reserves located in Central Appalachia, Northern Appalachia, the Illinois Basin and the Western Bituminous region. As of December 31, 2018, we controlled an estimated 268.5 million tons of proven and probable coal reserves, consisting of an estimated 214.0 million tons of steam coal and an estimated 54.5 million tons of metallurgical coal. Proven and probable coal reserves increased approximately 15.8 million tons from 2017 to 2018 primarily as the result of the revised economic feasibility of our non-reserve coal deposits. In addition, as of December 31, 2018, we controlled an estimated 164.1 million tons of non-reserve coal deposits, which decreased primarily due to the reclassification of non-reserve coal deposits to proven and probable reserves. For the year ended December 31, 2018, we purchased and sold 331 tons of third-party coal.

Coal Reserves

The following table provides information as of December 31, 2018 on the type, amount and ownership of the coal reserves:

Region	Proven and Probable Coal Reserves (1)								
	Total (3)	Proven	Probable	Assigned	Unassigned	Owned	Leased	Steam (2)	Metallurgical (2)
	(in million tons)								
Central Appalachia									
Tug River Complex (KY, WV)	23.0	19.8	3.2	18.8	4.3	9.2	13.8	13.0	10.0
Rob Fork Complex (KY)	14.0	12.9	1.1	14.0	-	6.4	7.6	11.6	2.4
Rhino Eastern Field (WV) (3)	33.9	19.4	14.4	29.1	4.7	-	33.9	-	33.9
Rich Mountain Field (WV)	8.2	2.7	5.5	-	8.2	8.2	-	-	8.2
Total Central Appalachia (5)	79.1	54.8	24.2	61.9	17.2	23.8	55.3	24.6	54.5
Northern Appalachia									
Hopedale Complex (OH)	18.6	15.2	3.5	18.6	-	4.0	14.6	18.6	-
Leesville Field (OH)	-	-	-	-	-	-	-	-	-
Springdale Field (PA)	13.7	8.8	4.9	-	13.7	13.7	-	13.7	-
Total Northern Appalachia (5)	32.3	24.0	8.4	18.6	13.7	17.7	14.6	32.3	-
Illinois Basin									
Taylorville Field (IL)	111.1	38.9	72.3	-	111.1	-	111.1	111.1	-
Pennyrile Complex (KY)	24.9	14.1	10.7	24.9	-	0.2	24.7	24.9	-
Total Illinois Basin (5)	136.0	53.0	83.0	24.9	111.1	0.2	135.8	136.0	-
Western Bituminous									
Castle Valley Complex (UT)	14.9	11.3	3.6	14.9	-	-	14.9	14.9	-
McClane Canyon Mine (CO) (4)	6.2	4.1	2.1	6.2	-	0.1	6.1	6.2	-
Total Western Bituminous (5)	21.1	15.4	5.7	21.1	-	0.1	21.0	21.1	-
Total (5)	268.5	147.2	121.3	126.5	142.0	41.8	226.7	214.0	54.5
Percentage of total (5)		54.8%	45.2%	47.1%	52.9%	15.6%	84.4%	79.7%	20.3%

(1) Represents recoverable tons. The recoverable tonnage estimates take into account mining losses and coal wash plant losses of material from both mining dilution and any non-coal material found within the coal seams. Except for coal expected to be processed and sold on a direct-shipped basis, a specific wash plant recovery factor has been estimated from representative exploration data for each coal seam and applied on a mine-by-mine basis to the estimates. Actual wash plant recoveries vary depending on customer coal quality specifications.

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

(3) The Rhino Eastern joint venture was dissolved in January 2015. As part of this dissolution, we received approximately 34 million tons of premium metallurgical coal reserves, which we have included in the proven and probable reserves listed above as of December 31, 2018.

(4) The McClane Canyon mine was permanently idled as of December 31, 2013.

(5) Percentages of totals are calculated based on actual amounts and not the rounded amounts presented in this table.

The majority of our leases have an initial term denominated in years but also provide for the term of the lease to continue until exhaustion of the "mineable and merchantable" coal in the lease area so long as the terms of the lease are complied with. Some of our leases have terms denominated in years rather than mine-to-exhaustion provisions, but in all such cases, we believe that the term of years will allow the recoverable reserves to be fully extracted in accordance with our projected mine plan. Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to lands and reserves of the lessors or grantors and the boundaries of our leased priorities are not completely verified until we prepare to mine those reserves.

The following table provides information on particular characteristics of our coal reserves as of December 31, 2018:

Region	As Received Basis (1) % Ash	% Sulfur	Btu/lb.	S02/mm Btu	Proven and Probable Coal Reserves (2) Total	Sulfur Content <1%	1-1.5%	>1.5%	Unknown
					(in million tons)				
Central Appalachia									
Tug River Complex (KY, WV)	9.42%	1.19%	13,145	1.80	23.0	9.9	9.7	2.5	0.9
Rob Fork Complex (KY)	5.41%	1.26%	13,527	1.87	14.0	6.5	4.3	1.6	1.6
Rhino Eastern Field (WV) (3)	4.17%	0.67%	14,035	0.96	33.9	28.8	4.9	-	0.2
Rich Mountain Field (WV)	7.28%	0.60%	13,235	0.91	8.2	8.2	-	-	-
Total Central Appalachia	6.24%	0.91%	13,611	1.34	79.1	53.4	18.9	4.1	2.7
Northern Appalachia									
Hopedale Complex (OH)	6.66%	2.26%	13,738	3.30	18.6	-	-	18.6	-
Springdale Field (PA)	7.08%	1.91%	13,337	2.87	13.7	-	-	13.7	-
Total Northern Appalachia	6.84%	2.11%	13,568	3.11	32.3	-	-	32.3	-
Illinois Basin									
Taylorville Field (IL)	7.75%	3.53%	11,057	6.38	111.1	-	-	111.1	-
Pennyrile Complex (KY)	7.79%	2.53%	11,475	4.42	24.9	-	-	24.9	-
Total Illinois Basin	7.76%	3.35%	11,133	6.01	136.0	-	-	136.0	-
Western Bituminous									
Castle Valley Complex (UT)	10.58%	0.90%	12,055	1.49	14.9	5.3	9.6	-	-
McClane Canyon Mine (CO) (4)	11.19%	0.57%	11,241	1.01	6.2	6.2	-	-	-
Total Western Bituminous	10.76%	0.80%	11,814	1.36	21.1	11.5	9.6	-	-
Total (5)	7.45%	2.29%	12,194	3.76	268.5	64.9	28.5	172.4	2.7
Percentage of total (5)						24.2%	10.6%	64.2%	1.0%

(1) As received basis represents average quality on a moist basis.

(2) Represents recoverable tons.

(3) The Rhino Eastern joint venture was dissolved in January 2015. As part of this dissolution, we received approximately 34 million tons of premium metallurgical coal reserves, which we have included in the proven and probable reserves listed above as of December 31, 2018.

(4) The McClane Canyon mine was permanently idled as of December 31, 2013.

(5) Totals and percentages of totals are calculated based on actual amounts and not the rounded amounts presented in this table.

Non-Reserve Coal Deposits

The following table provides information on our non-reserve coal deposits as of December 31, 2018:

Region	Non-Reserve Coal Deposits Total Tons	Total Tons Owned	Leased
	(in million tons)		
Central Appalachia	38.0	10.7	27.3
Northern Appalachia	60.6	55.8	4.8
Illinois Basin	35.9	-	35.9
Western Bituminous	29.6	-	29.6
Total	164.1	66.5	97.6
Percentage of total		40.52%	59.48%

Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to lands and non-reserve coal deposits of the lessors or grantors and the boundaries of our leased priorities are not completely verified until we prepare to mine the coal.

Office Facilities

We lease office space at 424 Lewis Hargett Circle, Lexington, Kentucky for our executives and administrative support staff. We executed an amendment to this lease in 2018 to extend the lease term for five additional years to July 31, 2023.

Item 3. Legal Proceedings.

We may, from time to time, be involved in various legal proceedings and claims arising out of our operations in the normal course of business. While many of these matters involve inherent uncertainty, we do not believe that we are a party to any legal proceedings or claims that will have a material adverse impact on our business, financial condition or results of operations.

Item 4. Mine Safety Disclosures.

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and

Consumer Protection Act and Item 104 of Regulation S-K for the year ended December 31, 2018 is included as Exhibit 95.1 to this report.

PART II

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

Our Limited Partnership Interests

Our common units continue to trade on the OTCQB Marketplace under the ticker symbol "RHNO."

Beginning with the quarter ended June 30, 2015 and continuing through the quarter ended December 31, 2018, we have suspended the cash distribution for our common units.

As of March 15, 2019, we had outstanding 13,098,353 common units, 1,143,686 subordinated units, 1,500,000 Series A preferred units, and a 0.4% general partner interest and incentive distribution rights ("IDRs"). As of March 15, 2019, Royal Energy Resources, Inc. ("Royal") owned approximately 49.4% of our outstanding common units and 93.2% of our subordinated units and our general partner. Our general partner currently owns a 0.4% general partner interest in us and all of our IDRs.

As of March 15, 2019, there were 84 holders of record of our common units. The number of record holders does not include holders of units in "street names" or persons, partnerships, associations, corporations or other entities identified in security position listings maintained by depositories.

Cash Distribution Policy

We will make a minimum quarterly distribution of $4.45 per common unit (or $17.80 per common unit on an annualized basis) to the extent we have sufficient available cash and when our cash distributions are not suspended. Available cash is generally defined as cash from operations after establishment by our general partner of cash reserves to provide for the conduct of our business, to comply with applicable law, any of our debt instruments or other agreements or to provide for future distributions to unitholders for any one or more of the next four quarters, and payment of costs and expenses, including reimbursement of expenses to our general partner and its affiliates. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement does not set a limit on the amount of cash reserves that our general partner may establish or the amount of expenses for which our general partner and its affiliates may be reimbursed. Available cash may also include, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter. We may also borrow to fund distributions in quarters when we generate less available cash than necessary to sustain or grow our cash distributions per unit.

There is no guarantee that we will distribute quarterly cash distributions to our unitholders. Our distribution policy is subject to certain restrictions and may be changed at any time. The reasons for such uncertainties in our stated cash distribution policy include the following factors:

- Our cash distribution policy is subject to restrictions on distributions under our Financing Agreement. Our Financing Agreement contains financial tests and covenants that we must satisfy. These financial tests and covenants are described in "Part II, Item 1. Business—Recent Developments-Financing Agreement." Should we be unable to satisfy these restrictions or if we are otherwise in default under our Financing Agreement, we would be prohibited from making cash distributions notwithstanding our cash distribution policy.

- Our general partner will have the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of or increase in those reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy. Our partnership agreement does not set a limit on the amount of cash reserves that our general partner may establish.

- Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our unitholders.

- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders. However, our partnership agreement can be amended with the consent of our general partner and the approval of a majority of the outstanding common units after the subordination period has ended.

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

- Under Section 17-607 of the Delaware Act, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.

- We may lack sufficient cash to pay distributions to our unitholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating or selling, general and administrative expenses, principal and interest payments on our outstanding debt, tax expenses, working capital requirements and anticipated cash needs.

- If we make distributions out of capital surplus, as opposed to operating surplus, such distributions will result in a reduction in the minimum quarterly distribution and the target distribution levels. However, we do not anticipate that we will make any distributions from capital surplus.

- Our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute cash to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations.

Our partnership agreement requires us to distribute all of our available cash each quarter in the following manner:

- first, 99.6% to the holders of common units and 0.4% to our general partner, until each common unit has received the minimum quarterly distribution of $4.45 plus any arrearages from prior quarters;

- second, 99.6% to the holders of subordinated units and 0.4% to our general partner, until each subordinated unit has received the minimum quarterly distribution of $4.45; and

- third, 99.6% to all unitholders, pro rata, and 0.4% to our general partner, until each unit has received a distribution of $5.1175.

If cash distributions to our unitholders exceed $5.1175 per unit in any quarter, our unitholders and our general partner, as the holder of the incentive distribution rights, will receive distributions according to the following percentage allocations:

	Marginal Percentage Interest in Distributions	
Total Quarterly Distribution Target Amount	**Unitholders**	**General Partner**
Above $5.1175 up to $5.5625	86.6%	13.4%
Above $5.5625 up to $6.675	76.6%	23.4%
Above $6.675	51.6%	48.4%

The percentage interest shown of our general partner includes its 0.4% general partner interest. Our general partner is entitled to 0.4% of all distributions that we make prior to our liquidation. Our partnership agreement provides our general partner the right, but not the obligation, to contribute capital to maintain its 0.4% general partner interest in us if we issue additional units in the future. Thus, if our general partner elects not to make such a capital contribution, its interest will be proportionately reduced.

During the subordination period, before we make any quarterly distributions to our subordinated unitholders, our common unitholders are entitled to receive payment of the minimum quarterly distribution plus any arrearages in distributions from prior quarters. The subordination period will end on the first business day after we have earned and paid at least (i) $17.80 (the minimum quarterly distribution on an annualized basis) on each outstanding unit and the corresponding distribution on our general partner's general partner interest for each of three consecutive, non-overlapping four quarter periods ending after September 30, 2013 or (ii) $26.70 (150.0% of the annualized minimum quarterly distribution) on each outstanding unit and the corresponding distributions on our general partner's general partner interest and the incentive distribution rights for the four-quarter period immediately preceding that date. The subordination period also will end upon the removal of our general partner other than for cause if no subordinated units or common units held by the holders of subordinated units or their affiliates are voted in favor of that removal. When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and all common units thereafter will no longer be entitled to arrearages.

We will pay any distributions on or about the 15th day of each of February, May, August and November to holders of record on or about the 1st day of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date.

Beginning with the quarter ended June 30, 2015 we have suspended the cash distribution for our common units. For each of the quarters ended September 30, 2014 and December 31, 2014 and March 31, 2015, we announced cash distributions at levels lower than the minimum quarterly distribution. Pursuant to our partnership agreement, our common units accrue arrearages every quarter when the distribution level is below the minimum level of $4.45 per unit. We have accumulated arrearages at December 31, 2018 related to the common unit distribution of approximately $673.1 million. In addition, we have not paid any distributions on our subordinated units for any quarter after the quarter ended March 31, 2012. Our subordinated units do not accrue arrearages for unpaid distributions.

Distributions on Preferred Units

On December 30, 2016, our general partner amended our partnership agreement to create, authorize and issue the Series A preferred units, and we issued 1,500,000 Series A preferred units.

The Series A preferred units are a new class of equity security that rank senior to all classes or series of our equity securities with respect to distribution rights and rights upon liquidation. The holders of the Series A preferred units are entitled to receive annual distributions equal to the greater of (i) 50% of the CAM Mining free cash flow (as defined below) and (ii) an amount equal to the number of outstanding Series A preferred units multiplied by $0.80. "CAM Mining free cash flow" is defined in our partnership agreement as (i) the total revenue of our Central Appalachia business segment, minus (ii) the cost of operations (exclusive of depreciation, depletion and amortization) for our Central Appalachia business segment, minus (iii) an amount equal to $6.50, multiplied by the aggregate number of met coal and steam coal tons sold by us from our Central Appalachia business segment. If we fail to pay any or all of the distributions in respect of the Series A preferred units, such deficiency will accrue until paid in full and we will not be permitted to pay any distributions on our partnership interests that rank junior to the Series A preferred units, including the common units. The Series A preferred units will be liquidated in accordance with their capital accounts and upon liquidation will be entitled to distributions of property and cash in accordance with the balances of their capital accounts prior to such distributions to equity securities that rank junior to the Series A preferred units.

Item 6. Selected Financial Data

The Registrant is a smaller reporting company and is not required to provide this information.

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

Unless the context clearly indicates otherwise, references in this report to "we," "our," "us" or similar terms refer to Rhino Resource Partners LP and its subsidiaries. References to our "general partner" refer to Rhino GP LLC, the general partner of Rhino Resource Partners LP.

The following discussion of the historical financial condition and results of operations should be read in conjunction with the historical financial statements and accompanying notes included elsewhere in this report. In addition, this discussion includes forward-looking statements that are subject to risks and uncertainties that may result in actual results differing from statements we make. See "Cautionary Note Regarding Forward- Looking Statements." Factors that could cause actual results to differ include those risks and uncertainties discussed in Part I, Item 1A. "Risk Factors."

On November 7, 2017, we closed an agreement with a third party to transfer 100% of the memberships interests and related assets and liabilities in our Sands Hill Mining entity to the third party in exchange for a future override royalty for any mineral sold, excluding coal, from Sands Hill Mining after the closing date. Our consolidated statements of operations and comprehensive income have been retrospectively adjusted to reclassify our Sands Hill Mining operation to discontinued operations for the year ended December 31, 2017.

Overview

We are a diversified coal producing limited partnership formed in Delaware that is focused on coal and energy related assets and activities. We produce, process and sell high quality coal of various steam and metallurgical grades. We market our steam coal primarily to electric utility companies as fuel for their steam powered generators. Customers for our metallurgical coal are primarily steel and coke producers who use our coal to produce coke, which is used as a raw material in the steel manufacturing process.

We have a geographically diverse asset base with coal reserves located in Central Appalachia, Northern Appalachia, the Illinois Basin and the Western Bituminous region. As of December 31, 2018, we controlled an estimated 268.5 million tons of proven and probable coal reserves, consisting of an estimated 214.0 million tons of steam coal and an estimated 54.5 million tons of metallurgical coal. Proven and probable coal reserves increased approximately 15.8 million tons from 2017 to 2018 primarily as the result of the revised economic feasibility of our non-reserve coal deposits. In addition, as of December 31, 2018, we controlled an estimated 164.1 million tons of non-reserve coal deposits, which decreased primarily due to the reclassification of non-reserve coal deposits to proven and probable reserves. Periodically, we retain outside experts to independently verify our coal reserve and our non-reserve coal deposit estimates. The most recent audit by an independent engineering firm of our coal reserve and non-reserve coal deposit estimates was completed by Marshall Miller & Associates, Inc. as of December 31, 2018, and covered a majority of the coal reserves and non-reserve coal deposits that we controlled as of such date. We intend to continue to periodically retain outside experts to assist management with the verification of our estimates of our coal reserves and non-reserve coal deposits going forward.

We operate underground and surface mines located in Kentucky, Ohio, West Virginia and Utah. The number of mines that we operate will vary from time to time depending on a number of factors, including the existing demand for and price of coal, depletion of economically recoverable reserves and availability of experienced labor.

Our principal business strategy is to safely, efficiently and profitably produce and sell both steam and metallurgical coal from our diverse asset base in order to resume, and, over time, increase our quarterly cash distributions. In addition, we intend to continue to expand and potentially diversify our operations through strategic acquisitions, including the acquisition of long-term, cash generating natural resource assets. We believe that such assets will allow us to grow our cash available for distribution and enhance stability of our cash flow.

For the year ended December 31, 2018, we generated revenues from continuing operations of approximately $247.0 million and a net loss from continuing operations of approximately $16.0 million. For the year ended December 31, 2018, we produced approximately 4.4 million tons of coal from continuing operations and sold approximately 4.6 million tons of coal from continuing operations, approximately 64.0% of which were pursuant to long-term supply contracts.

Current Liquidity and Outlook

As of December 31, 2018, our available liquidity was $6.2 million. We also have a delayed draw term loan commitment in the amount of $35 million contingent upon the satisfaction of certain conditions precedent specified in the financing agreement discussed below.

On December 27, 2017, we entered into a Financing Agreement ("Financing Agreement"), which provides us with a multi-draw loan in the aggregate principal amount of $80 million. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the Financing Agreement and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement. We used approximately $17.3 million of the net proceeds thereof to repay all amounts outstanding and terminate the Amended and Restated Credit Agreement with PNC Bank, National Association, as Administrative Agent. The Financing Agreement terminates on December 27, 2020. For more information about our Financing Agreement, please read "— Recent Developments—Financing Agreement."

We continue to take measures, including the suspension of cash distributions on our common and subordinated units and cost and productivity improvements, to enhance and preserve our liquidity so that we can fund our ongoing operations and necessary capital expenditures and meet our financial commitments and debt service obligations.

Recent Developments

Financing Agreement

On December 27, 2017, we entered into a Financing Agreement with Cortland Capital Market Services LLC, as Collateral Agent and Administrative agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders (the "Lenders") therein, pursuant to which Lenders agreed to provide us with a multi-draw term loan in the aggregate principal amount of $80 million, subject to the terms and conditions set forth in the Financing Agreement. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the Financing Agreement ("Effective Date Term Loan Commitment") and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement ("Delayed Draw Term Loan Commitment"). Loans made pursuant to the Financing Agreement are secured by substantially all of our assets. The Financing Agreement terminates on December 27, 2020. For more information about our Financing Agreement, please read "— Liquidity and Capital Resources—Financing Agreement."

On April 17, 2018, we amended the Financing Agreement to allow for certain activities including a sale leaseback of certain pieces of equipment, the due date for the lease consents was extended to June 30, 2018 and confirmation of the distribution to holders of the Series A preferred units of $6.0 million (accrued in our consolidated financial statements at December 31, 2017). Additionally, the amendments provide that we could sell additional shares of Mammoth Inc. stock and retain 50% of the proceeds with the other 50% used to reduce debt. We reduced the debt by $3.4 million with proceeds from the sale of Mammoth Inc. stock in the second quarter of 2018.

On July 27, 2018, we entered into a consent with our Lenders related to the Financing Agreement. The consent included the lenders agreement to make a $5 million loan from the Delayed Draw Term Loan Commitment, which was repaid in full on October 26, 2018 pursuant to the terms of the consent. The consent also included a waiver of the requirements relating to the use of proceeds of any sale of the shares of Mammoth Inc. set forth in the consent to the Financing Agreement, dated as of April 17, 2018 and also waived any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended June 30, 2018.

On November 8, 2018, we entered into a consent with our Lenders related to the Financing Agreement. The consent includes the lenders agreement to waive any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended September 30, 2018.

On December 20, 2018, we entered into a limited waiver and consent (the "Waiver") to the Financing Agreement. The Waiver relates to the sales of certain real property in Western Colorado, the net proceeds of which are required to be used to reduce our debt under the Financing Agreement. As of the date of the Waiver, we had sold 9 individual lots in smaller transactions. Rather than transmitting net proceeds with respect to each individual transaction, we agreed with the Lenders in principle to delay repayment until an aggregate payment could be made at the end of 2018. On December 18, 2018, we used the sale proceeds of approximately $379,000 to reduce the debt. The Waiver (i) contains a ratification by the Lenders of the sale of the individual lots to date and waives the associated technical defaults under the Financing Agreement for not making immediate payments of net proceeds therefrom, (ii) permits the sale of certain specified additional lots and (iii) subject to Lender consent, permits the sale of other lots on a going forward basis. The net proceeds of future sales will be held by us until a later date to be determined by the Lenders.

On February 13, 2019, we entered into a second amendment ("Amendment") to the Financing Agreement. The Amendment provides the Lender's consent for us to pay a one-time cash distribution on February 14, 2019 to the Series A Preferred Unitholders not to exceed approximately $3.2 million. The Amendment allows us to sell our remaining shares of Mammoth Energy Services, Inc. and utilize the proceeds for payment of the one-time cash distribution to the Series A Preferred Unitholders and waives the requirement to use such proceeds to prepay the outstanding principal amount outstanding under the Financing Agreement. The Amendment also waives any Event of Default that has or would otherwise arise under Section 9.01(c) of the Financing Agreement solely by reason of us failing to comply with the Fixed Charge Coverage Ratio covenant in Section 7.03(b) of the Financing Agreement for the fiscal quarter ending December 31, 2018. The Amendment includes an amendment fee of approximately $0.6 million payable by us on May 13, 2019 and an exit fee equal to 1% of the principal amount of the term loans made under the Financing Agreement that is payable on the earliest of (w) the final maturity date of the Financing Agreement, (x) the termination date of the Financing Agreement, (y) the acceleration of the obligations under the Financing Agreement for any reason, including, without limitation, acceleration in accordance with Section 9.01 of the Financing Agreement, including as a result of the commencement of an insolvency proceeding and (z) the date of any refinancing of the term loan under the Financing Agreement. The Amendment amends the definition of the Make-Whole Amount under the Financing Agreement to extend the date of the Make-Whole Amount period to December 31, 2019.

Common Unit Warrants

In December 2017, we entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. The warrant agreement included the issuance of a total of 683,888 warrants of our common units ("Common Unit Warrants") at an exercise price of $1.95 per unit, which was the closing price of our common units on the OTC market as of December 27, 2017. The Common Unit Warrants have a five year expiration date. The Common Unit Warrants and our common units after exercise are both transferable, subject to applicable US securities laws. The Common Unit Warrant exercise price is $1.95 per unit, but the price per unit will be reduced by future common unit distributions and other further adjustments in price included in the warrant agreement for transactions that are dilutive to the amount of Rhino's common units outstanding. The warrant agreement includes a provision for a cashless exercise where the warrant holders can receive a net number of common units. Per the warrant agreement, the warrants are detached from the Financing Agreement and fully transferable.

Letter of Credit Facility – PNC Bank

On December 27, 2017, we entered into a master letter of credit facility, security agreement and reimbursement agreement (the "LoC Facility Agreement") with PNC Bank, National Association ("PNC"), pursuant to which PNC agreed to provide us with a facility for the issuance of standby letters of credit used in the ordinary course of our business (the "LoC Facility"). The LoC Facility Agreement provided that we pay a quarterly fee at a rate equal to 5% per annum calculated based on the daily average of letters of credit outstanding under the LoC Facility, as well as administrative costs incurred by PNC and a $100,000 closing fee. The LoC Facility Agreement provided that we reimburse PNC for any drawing under a letter of credit by a specified beneficiary as soon as possible after payment was made. Our obligations under the LoC Facility Agreement were secured by a first lien security interest on a cash collateral account that was required to contain no less than 105% of the face value of the outstanding letters of credit. In the event the amount in such cash collateral account was insufficient to satisfy our reimbursement obligations, the amount outstanding would bear interest at a rate per annum equal to the Base Rate (as that term was defined in the LoC Facility Agreement) plus 2.0%. We would indemnify PNC for any losses which PNC may have incurred as a result of the issuance of a letter of credit or PNC's failure to honor any drawing under a letter of credit, subject in each case to certain exceptions. We provided cash collateral to our counterparties during the third quarter of 2018 and as of September 30, 2018, the LoC Facility was terminated. We had no outstanding letters of credit as of December 31, 2018.

Distribution Suspension

Beginning with the quarter ended June 30, 2015 and continuing through the quarter ended December 31, 2018, we have suspended the cash distribution on our common units. For each of the quarters ended September 30, 2014, December 31, 2014 and March 31, 2015, we announced cash distributions per common unit at levels lower than the minimum quarterly distribution. We have not paid any distribution on our subordinated units for any quarter after the quarter ended March 31, 2012. The distribution suspension and prior reductions were the result of prolonged weakness in the coal markets, which has continued to adversely affect our cash flow.

Pursuant to our partnership agreement, our common units accrue arrearages every quarter when the distribution level is below the minimum level of $4.45 per unit. Since our distributions for the quarters ended September 30, 2014, December 31, 2014 and March 31, 2015 were below the minimum level and we altogether suspended the distribution beginning with the quarter ended June 30, 2015, we have accumulated arrearages at December 31, 2018 related to the common unit distribution of approximately $673.1 million.

Asset Impairments-2018

We performed a comprehensive review of our coal mining operations as well as potential future development projects for the year ended December 31, 2018 to ascertain any potential impairment losses. We did not record any impairment losses for coal properties, mine development costs or coal mining equipment and related facilities for the year ended December 31, 2018.

Asset Impairments-2017

We performed a comprehensive review of our coal mining operations as well as potential future development projects for the year ended December 31, 2017 to ascertain any potential impairment losses. We engaged an independent third party to perform a fair market value appraisal on certain parcels of land that we own in Mesa County, Colorado. The parcels appraised for $6.0 million compared to the carrying value of $6.8 million. We recorded an impairment loss of $0.8 million, which is recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income. No other coal properties, mine development costs or other coal mining equipment and related facilities were impaired as of December 31, 2017.

We recorded an impairment charge of $21.8 million related to the call option received from a third party to acquire substantially all of the outstanding common stock of Armstrong Energy, Inc. On October 31, 2017, Armstrong Energy filed Chapter 11 petitions in the Eastern District of Missouri's United States Bankruptcy Court. Per the Chapter 11 petitions, Armstrong Energy filed a detailed restructuring plan as part of the Chapter 11 proceedings. On February 9, 2018, the U.S. Bankruptcy Court confirmed Armstrong Energy's Chapter 11 reorganization plan and as such we concluded that the call option had no carrying value. An impairment charge of $21.8 million related to the call option was recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income.

Factors That Impact Our Business

Our results of operations in the near term could be impacted by a number of factors, including (1) our ability to fund our ongoing operations and necessary capital expenditures, (2) the availability of transportation for coal shipments, (3) poor mining conditions resulting from geological conditions or the effects of prior mining, (4) equipment problems at mining locations, (5) adverse weather conditions and natural disasters or (6) the availability and costs of key supplies and commodities such as steel, diesel fuel and explosives.

On a long-term basis, our results of operations could be impacted by, among other factors, (1) our ability to fund our ongoing operations and necessary capital expenditures, (2) changes in governmental regulation, (3) the availability and prices of competing electricity-generation fuels, (4) the world-wide demand for steel, which utilizes metallurgical coal and can affect the demand and prices of metallurgical coal that we produce, (5) our ability to secure or acquire high-quality coal reserves and (6) our ability to find buyers for coal under favorable supply contracts.

We have historically sold a majority of our coal through supply contracts and anticipate that we will continue to do so. As of December 31, 2018, we had commitments under supply contracts to deliver annually scheduled base quantities of coal as follows:

Year	Tons (in thousands)	Number of customers
2019	3,699	18
2020	1,979	6
2021	352	2

Some of the contracts have sales price adjustment provisions, subject to certain limitations and adjustments, based on a variety of factors and indices.

Results of Operations

Segment Information

As of December 31, 2018, we have four reportable business segments: Central Appalachia, Northern Appalachia, Rhino Western and Illinois Basin. Additionally, we have an Other category that includes our ancillary businesses. Our Central Appalachia segment consists of two mining complexes: Tug River and Rob Fork, which, as of December 31, 2018, together included one underground mine, three surface mines and three preparation plants and loadout facilities in eastern Kentucky and southern West Virginia. Our Northern Appalachia segment consists of the Hopedale mining complex and the Leesville field. The Hopedale mining complex, located in northern Ohio, included one underground mine and one preparation plant and loadout facility as of December 31, 2018. Our Rhino Western segment includes one underground mine in the Western Bituminous region at our Castle Valley mining complex in Utah. Our Illinois Basin segment includes one underground mine, preparation plant and river loadout facility at our Pennyrile mining complex located in western Kentucky, as well as our Taylorville field reserves located in central Illinois. Our Other category is comprised of our ancillary businesses.

Evaluating Our Results of Operations

Our management uses a variety of non-GAAP financial measurements to analyze our performance, including (1) Adjusted EBITDA, (2) coal revenues per ton and (3) cost of operations per ton.

Adjusted EBITDA. The discussion of our results of operations below includes references to, and analysis of, our segments' Adjusted EBITDA results. Adjusted EBITDA represents net income before deducting interest expense, income taxes and depreciation, depletion and amortization, while also excluding certain non-cash and/or non-recurring items. Adjusted EBITDA is used by management primarily as a measure of our segments' operating performance. Adjusted EBITDA should not be considered an alternative to net income, income from operations, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Because not all companies calculate Adjusted EBITDA identically, our calculation may not be comparable to similarly titled measures of other companies. Please read "—Reconciliation of Adjusted EBITDA" for reconciliations of Adjusted EBITDA to net income by segment for each of the periods indicated.

Coal Revenues Per Ton. Coal revenues per ton represents coal revenues divided by tons of coal sold. Coal revenues per ton is a key indicator of our effectiveness in obtaining favorable prices for our product.

Cost of Operations Per Ton. Cost of operations per ton sold represents the cost of operations (exclusive of DD&A) divided by tons of coal sold. Management uses this measurement as a key indicator of the efficiency of operations.

On November 7, 2017, we closed an agreement with a third party to transfer 100% of the membership interests and related assets and liabilities in Sands Hill Mining LLC to the third party in exchange for a future override royalty for any mineral sold, excluding coal, from Sands Hill Mining LLC after the closing date. We recognized a gain of $3.2 million from the sale of Sands Hill Mining LLC since the third party assumed the reclamation obligations associated with this operation. The historical results for Sands Hill Mining LLC together with the gain on sale have been presented as discontinued operations.

Summary. (The following discussions of financial and operational data for the years ended December 31, 2018 and 2017 pertain to continuing operations unless otherwise specified.)

The following table sets forth certain information regarding our revenues, operating expenses, other income and expenses, and operational data for years ended December 31, 2018 and 2017:

	Year Ended December 31,		Increase/(Decrease)	
	2018	2017	$	% *
	(in millions, except per ton data and %)			
Statement of Operations Data:				
Coal revenues	$ 244.3	$ 217.2	$ 27.1	12.5%
Other revenues	2.7	1.5	1.2	84.6%
Total revenues	247.0	218.7	28.3	13.0%
Costs and expenses:				
Cost of operations (exclusive of DD&A shown separately below)	213.6	178.5	35.1	19.7%
Freight and handling costs	9.0	1.8	7.2	394.5%
Depreciation, depletion and amortization	22.3	21.1	1.2	5.8%
Selling, general and administrative (exclusive of DD&A shown separately above)	12.9	11.4	1.5	13.0%
Asset impairment and related charges	-	22.6	(22.6)	(100.0%)
Impact from adoption of ASU 2016-01	0.2	-	0.2	n/a
(Gain)/loss on sale/disposal of assets	(3.4)	-	(3.4)	n/a
(Loss) from operations	(7.6)	(16.7)	9.1	(54.5%)
Interest expense and other	8.5	4.0	4.5	111.5%
Interest income and other	(0.1)	(0.1)	-	(21.9%)
Total interest and other (income) expense	8.4	3.9	4.5	116.5%
Net (loss) from continuing operations	(16.0)	(20.6)	4.6	(22.3%)
Net income from discontinued operations	-	1.8	(1.8)	(100.0%)
Net (loss)	$ (16.0)	$ (18.8)	$ 2.8	(14.7%)
Total tons sold	4,598.0	4,125.6	472.4	11.5%
Coal revenues per ton	$ 53.13	$ 52.64	$ 0.49	0.9%
Cost of operations per ton	$ 46.45	$ 43.26	$ 3.19	7.4%
Other Financial Data				
Adjusted EBITDA from continuing operations	$ 19.6	$ 27.1	$ (7.5)	(27.9%)
Adjusted EBITDA from discontinued operations	-	(0.8)	0.8	(100.0%)
Adjusted EBITDA	$ 19.6	$ 26.3	$ (6.7)	(25.5%)

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Summary. For the year ended December 31, 2018, our total revenues increased to $247.0 million from $218.7 million for the year ended December 31, 2017. We sold 4.6 million tons of coal during the year ended December 31, 2018, which was an increase of 0.5 million tons, or an 11.5% increase, from the 4.1 million tons of coal sold during the year ended December 31, 2017. The increase in revenue and tons sold was primarily the result of increased sales in Central Appalachia due to an increase in demand for met and steam coal produced in this region.

Cost of Operations. Total cost of operations increased by $35.1 million or 19.7% to $213.6 million for the year ended December 31, 2018 as compared to $178.5 million for the year ended December 31, 2017. Our cost of operations per ton was $46.45 for the year ended December 31, 2018, an increase of $3.19, or 7.4%, from the year ended December 31, 2017. The increase in cost of operations was primarily due to the $33.5 million increase in cost of operations at our Central Appalachia operations as demand for met and steam coal increased in this region. We also experienced an increase in the cost for diesel fuel, contract services and equipment maintenance in our Central Appalachia segment which resulted in the cost of operations per ton increasing during 2018 compared to 2017.

Freight and Handling. Total freight and handling cost increased to $9.0 million for the year ended December 31, 2018 as compared to $1.8 million for the year ended December 31, 2017. The increase in freight and handling costs was primarily the result of rail transportation costs in our Central Appalachia operations as we executed more export coal sales in the period that required us to pay for railroad transportation to the port of export. We also incurred $1.1 in demurrage charges during 2018 due to rail transportation constraints that caused shipments to be delayed to the port of export.

Depreciation, Depletion and Amortization. Total DD&A expense for the year ended December 31, 2018 was $22.3 million as compared to $21.1 million for the year ended December 31, 2017.

For the year ended December 31, 2018, our depreciation expense increased to $16.9 million compared to $16.2 million for the year ended December 31, 2017. This increase was the result of adding new equipment to meet the increased demand for coal.

For the year ended December 31, 2018, our depletion expense increased to $1.9 million compared to $1.7 million for the year ended December 31, 2017. This increase is primarily due to the increase in tons produced in 2018 compared to 2017.

For the year ended December 31, 2018, our amortization expense increased to $3.6 million as compared to $3.2 million for the year ended December 31, 2017. The increase is the result of increased production at our Central Appalachia operations during 2018.

Selling, General and Administrative. SG&A expense for the year ended December 31, 2018 increased to $12.9 million as compared to $11.4 million for the year ended December 31, 2017 primarily due to bad debt expense of $0.9 million recognized in 2018.

Interest Expense. Interest expense for the year ended December 31, 2018 increased to $8.5 million as compared to $4.0 million for the year ended December 31, 2017. This increase was primarily due to the higher outstanding debt balance and the effective interest rate on our new Financing Agreement.

Net Loss. Net loss was approximately $16.0 million for the year ended December 31, 2018 compared to a net loss of approximately $20.6 million for the year ended December 31, 2017. Net loss for the year ended December 31, 2018 was primarily the result of a decrease in contracted sale prices for tons sold from our Pennyrile mine and an increase in the costs for freight and handling, contract services, equipment maintenance and diesel fuel at our Central Appalachia operations during 2018. The net loss for the year ended December 31, 2017 was primarily the result of $22.6 million in asset impairments. The asset impairments and related charges included an $0.8 million impairment of land owned by us in Mesa, Colorado included in our Western segment and a $21.8 million impairment of the Armstrong call option included in the Other category (please read —"Asset Impairments-2017" above for additional discussion).

Adjusted EBITDA. Adjusted EBITDA from continuing operations decreased to $19.6 million for the year ended December 31, 2018 as compared to $27.1 million for the year ended December 31, 2017. The decrease in Adjusted EBITDA from continuing operations during the year ended December 31, 2018 was primarily due to a decrease in net income at our Illinois Basin segment resulting from the decrease in the contracted sale prices for tons sold from our Pennyrile mine and an increase in operating costs such as freight and handling, contract services and diesel fuel at our Central Appalachia operations. Including net income from discontinued operations of approximately $1.8 million, which related to our Sands Hill Mining operation sold in November 2017, our net loss was $18.8 million and Adjusted EBITDA was $26.3 million for the year ended December 31, 2017. We did not incur a gain or loss from discontinued operations for the year ended December 31, 2018.

Segment Results

The following tables set forth certain information regarding our revenues, operating expenses, other income and expenses, and operational data by reportable segment for the years ended December 31, 2018 and 2017:

Central Appalachia	Year Ended December 31,		Increase/(Decrease)	
	2018	2017	$	% *
	(in millions, except per ton data and %)			
Coal revenues	$ 139.4	$ 101.8	$ 37.6	36.9%
Freight and handling revenues	-	-	-	n/a
Other revenues	0.3	0.2	0.1	142.1%
Total revenues	139.7	102.0	37.7	37.0%
Coal revenues per ton	$ 74.78	$ 69.68	$ 5.10	7.3%
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	112.1	78.6	33.5	42.7%
Freight and handling costs	9.0	1.8	7.2	395.7%
Depreciation, depletion and amortization	8.7	7.7	1.0	13.6%
Selling, general and administrative costs	0.9	0.2	0.7	365.2%
Cost of operations per ton	$ 60.16	$ 53.76	$ 6.40	11.9%
Net income from continuing operations	8.8	13.7	(4.9)	(36.0%)
Adjusted EBITDA from continuing operations	18.3	21.4	(3.1)	(14.7%)
Tons sold	1,864.2	1,461.6	402.6	27.5%

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

Tons of coal sold in our Central Appalachia segment increased by approximately 27.5% to approximately 1.9 million tons for the year ended December 31, 2018 compared to the year ended December 31, 2017, primarily due to an increase in demand for met and steam coal tons from this region.

Coal revenues increased by approximately $37.6 million, or 36.9%, to approximately $139.4 million for the year ended December 31, 2018 from approximately $101.8 million for the year ended December 31, 2017. This increase was primarily due to the increase in demand for met and steam coal tons sold from this region. Coal revenues per ton for our Central Appalachia segment increased by $5.10, or 7.3%, to $74.78 per ton for the year ended December 31, 2018 as compared to $69.68 for the year ended December 31, 2017. This increase was primarily due to the increase in contracted sale prices for our met coal from this region.

Cost of operations increased by $33.5 million, or 42.7%, to $112.1 million for the year ended December 31, 2018 from $78.6 million for the year ended December 31, 2017. Our cost of operations per ton of $60.16 for the year ended December 31, 2018 increased 11.9% compared to $53.76 per ton for the year ended December 31, 2017. Total cost of operations and cost of operations per ton increased period over period as we increased sales in this region during 2018 and experienced an increase in operating expenses such as diesel fuel, contract services and equipment maintenance compared to 2017.

Total freight and handling cost increased to $9.0 million for the year ended December 31, 2018 from approximately $1.8 million for the year ended December 31, 2017. The increase in freight and handling costs was primarily the result of rail transportation costs at our Central Appalachia operations as we executed more export coal sales in the period that required us to pay for railroad transportation to the port of export. We also incurred $1.1 million in demurrage charges due to rail transportation constraints that caused shipments to be delayed to the port of export.

For our Central Appalachia segment, net income was approximately $8.8 million for the year ended December 31, 2018, a decrease of $4.9 million in net income as compared to the year ended December 31, 2017. Net income was impacted by an increase in the cost of operations and freight and handling charges discussed above.

Central Appalachia Overview of Results by Product. Additional information for the Central Appalachia segment detailing the types of coal produced and sold, premium high-vol met coal and steam coal for the years ended December 31, 2018 and 2017, is presented below. Note that our Northern Appalachia, Rhino Western and Illinois Basin segments currently produce and sell only steam coal.

(In thousands, except per ton data and %)	Year ended December 31, 2018	Year ended December 31, 2017	Increase (Decrease) %*
Met coal tons sold	873.9	737.3	18.5%
Steam coal tons sold	990.2	724.3	36.7%
Total tons sold	1,864.1	1,461.6	27.5%
Met coal revenue	$ 87,015	$ 64,033	35.9%
Steam coal revenue	$ 52,380	$ 37,805	38.6%
Total coal revenue	$ 139,395	$ 101,838	36.9%
Met coal revenues per ton	$ 99.57	$ 86.85	14.6%
Steam coal revenues per ton	$ 52.90	$ 52.19	1.4%
Total coal revenues per ton	$ 74.78	$ 69.68	7.3%
Met coal tons produced	515.5	645.8	(20.2%)
Steam coal tons produced	1,229.3	904.8	35.9%
Total tons produced	1,744.8	1,550.6	12.5%

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

Northern Appalachia

	Year Ended December 31,		Increase/(Decrease)	
	2018	2017	$	% *
	(in millions, except per ton data and %)			
Coal revenues	$ 18.2	$ 15.9	$ 2.3	15.0%
Freight and handling revenues	-	-	-	n/a
Other revenues	2.2	1.3	0.9	71.2%
Total revenues	20.4	17.2	3.2	19.2%
Coal revenues per ton	$ 43.05	$ 41.58	$ 1.47	3.5%
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	23.5	19.2	4.3	22.5%
Freight and handling costs	-	-	-	n/a
Depreciation, depletion and amortization	1.2	1.0	0.2	23.5%
Selling, general and administrative costs	0.2	-	0.2	186.3%
Cost of operations per ton	$ 55.48	$ 50.34	$ 5.14	10.2%
Net loss from continuing operations	(4.4)	(3.1)	(1.3)	42.9%
Adjusted EBITDA from continuing operations	(3.1)	(2.1)	(1.0)	46.0%
Tons sold	423.6	381.3	42.3	11.1%

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

For our Northern Appalachia segment, tons of coal sold increased by approximately 11.1% for the year ended December 31, 2018 compared to the year ended December 31, 2017 as we experienced increased demand for coal from this region.

Coal revenues were approximately $18.2 million for the year ended December 31, 2018, an increase of approximately $2.3 million, or 15.0%, from approximately $15.9 million for the year ended December 31, 2017. Coal revenues per ton increased by $1.47 or 3.5% to $43.05 per ton for the year ended December 31, 2018, as compared to $41.58 for the year ended December 31, 2017, which was primarily due to an increase in contracted sale prices for tons sold from our Hopedale complex compared to the prior year.

Cost of operations increased by $4.3 million, or 22.5%, to $23.5 million for the year ended December 31, 2018 from $19.2 million for the year ended December 31, 2017. Our cost of operations per ton was $55.48 for the year ended December 31, 2018, an increase of $5.14, or 10.2%, compared to $50.34 for the year ended December 31, 2017. The increase in total cost of operations and cost of operations per ton was primarily the result of an increase in maintenance costs and costs for outside services.

Net loss in our Northern Appalachia segment was $4.4 million for the year ended December 31, 2018 compared to net loss of $3.1 million for the year ended December 31, 2017. The increase in net loss for the year ended December 31, 2018 was primarily due to the increase in the cost of operations partially offset by the increase in contracted prices of tons sold compared to the same period in 2017.

Rhino Western	Year Ended December 31,		Increase/(Decrease)	
	2018	2017	$	% *
	(in millions, except per ton data and %)			
Coal revenues	$ 36.2	$ 35.4	$ 0.8	2.1%
Freight and handling revenues	-	-	-	n/a
Other revenues	-	-	-	n/a
Total revenues	36.2	35.4	0.8	2.1%
Coal revenues per ton	$ 35.40	$ 37.54	$ (2.14)	(5.7%)
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	30.5	28.3	2.2	7.7%
Freight and handling costs	-	-	-	n/a
Depreciation, depletion and amortization	4.1	4.4	(0.3)	(8.5%)
Selling, general and administrative costs	0.1	0.1	-	59.9%
Cost of operations per ton	$ 29.80	$ 29.96	$ (0.16)	(0.5%)
Net income from continuing operations	1.4	1.7	(0.3)	(17.6%)
Adjusted EBITDA from continuing operations	5.5	7.0	(1.5)	(22.1%)
Tons sold	1,022.3	944.2	78.1	8.3%

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

Tons of coal sold from our Rhino Western segment increased by approximately 8.3% for the year ended December 31, 2018 compared to 2017 primarily due to an increase in demand for coal from this region.

Coal revenues increased by approximately $0.8 million, or 2.1%, to approximately $36.2 million for the year ended December 31, 2018 from approximately $35.4 million for the year ended December 31, 2017 primarily due to an increase in demand for tons sold from the Castle Valley mine during 2018. Coal revenues per ton for our Rhino Western segment decreased by $2.14 or 5.7% to $35.40 per ton for the year ended December 31, 2018 as compared to $37.54 per ton for the year ended December 31, 2017 due to lower contracted sale prices.

Cost of operations increased by $2.2 million, or 7.7%, to $30.5 million for the year ended December 31, 2018 from $28.3 million for the year ended December 31, 2017. Our cost of operations per ton was $29.80 for the year ended December 31, 2018, a decrease of $0.16, or 0.5%, compared to $29.96 for the year ended December 31, 2017. Total cost of operations increased for the year ended December 31, 2018 compared to 2017 as we saw an increase in in demand for coal from this region. The cost of operations per ton decreased slightly during 2018 compared to 2017.

Net income in our Rhino Western segment was $1.4 million for the year ended December 31, 2018, compared to net income of $1.7 million for the year ended December 31, 2017. This decrease in net income was primarily the result of lower contracted sale prices for tons sold at our Castle Valley operation.

Illinois Basin	Year Ended December 31,		Increase/(Decrease)	
	2018	2017	$	% *
	(in millions, except per ton data and %)			
Coal revenues	$ 50.5	$ 64.1	$ (13.6)	(21.2%)
Freight and handling revenues	-	-	-	n/a
Other revenues	-	-	-	n/a
Total revenues	50.5	64.1	(13.6)	(21.2%)
Coal revenues per ton	$ 39.17	$ 47.85	$ (8.68)	(18.1%)
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	50.2	54.6	(4.4)	(8.2%)
Freight and handling costs	-	-	-	n/a
Depreciation, depletion and amortization	7.9	7.6	0.3	4.4%
Selling, general and administrative costs	0.2	0.2	-	13.0%
Cost of operations per ton	$ 38.94	$ 40.81	$ (1.87)	(4.6%)
Net (loss)/income from continuing operations	(7.7)	1.7	(9.4)	(543.4%)
Adjusted EBITDA from continuing operations	0.2	9.3	(9.1)	(97.6%)
Tons sold	1,287.9	1,338.5	(50.6)	(3.8%)

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

For our Illinois Basin segment, tons of coal sold decreased by approximately 3.8% for the year ended December 31, 2018 compared to the year ended December 31, 2017.

Coal revenues of approximately $50.5 million for the year ended December 31, 2018 decreased by approximately $13.6 million, or 21.2%, compared to $64.1 million for the year ended December 31, 2017. Coal revenues per ton for our Illinois Basin segment were $39.17 for the year ended December 31, 2018, a decrease of $8.68, or 18.1%, from $47.85 for the year ended December 31, 2017. The decrease in coal revenues and coal revenues per ton were primarily due to lower contracted prices for tons sold from our Pennyrile mine in western Kentucky.

Cost of operations was $50.2 million while cost of operations per ton was $38.94 for the year ended December 31, 2018, both of which related to our Pennyrile mining complex in western Kentucky. For the year ended December 31, 2017, cost of operations in our Illinois Basin segment was $54.6 million and cost of operations per ton was $40.81. The decrease in cost of operations and cost of operations per ton for the year ended December 31, 2018 was primarily the result of fewer tons being produced and lower operating costs at our Pennyrile mining complex during the year ended December 31, 2018.

For our Illinois Basin segment, we generated a net loss of $7.7 million for the year ended December 31, 2018 compared to net income of $1.7 million for the year ended December 31, 2017. The net loss was primarily the result of a decrease in the contracted sale prices for tons sold during 2018 compared to 2017.

Other	Year Ended December 31,		Increase/(Decrease)	
	2018	2017	$	% *
	(in millions, except per ton data and %)			
Coal revenues	n/a	n/a	n/a	n/a
Freight and handling revenues	n/a	n/a	n/a	n/a
Other revenues	$ 0.2	$ -	$ 0.2	339.3%
Total revenues	0.2	-	0.2	339.3%
Coal revenues per ton**		n/a	n/a	n/a
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	(2.7)	(2.2)	(0.5)	22.9%
Freight and handling costs	-	-	-	n/a
Depreciation, depletion and amortization	0.4	0.4	-	(1.7%)
Selling, general and administrative costs	11.4	10.9	0.5	4.9%
Cost of operations per ton**	n/a	n/a	n/a	n/a
Net loss from continuing operations	(14.1)	(34.6)	20.5	(59.4%)
Adjusted EBITDA from continuing operations	(1.3)	(8.5)	7.2	(84.6%)
Tons sold	n/a	n/a	n/a	n/a

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

** The Other category includes results for our ancillary businesses. The activities performed by these ancillary businesses do not directly relate to coal production. As a result, coal revenues and coal revenues per ton are not presented for the Other category. Cost of operations presented for our Other category includes costs incurred by our ancillary businesses. As a result, cost per ton measurements are not presented for this category.

Other revenues for our Other category were $0.2 million for the year ended December 31, 2018 compared to approximately $41,000 for the year ended December 31, 2017.

For the Other category, we had net loss from continuing operations of $14.1 million for the year ended December 31, 2018 as compared to net loss from continuing operations of $34.6 million for the year ended December 31, 2017. The net loss for the year ended December 31, 2018 was impacted by an increase of approximately $4.5 million in interest expense. Net loss for the year ended December 31, 2017 was primarily attributable to the $21.8 million asset impairment recorded for the Armstrong call option as discussed earlier in this section.

Reconciliation of Adjusted EBITDA

The following tables present reconciliations of Adjusted EBITDA to the most directly comparable GAAP financial measures for each of the periods indicated. Adjusted EBITDA excludes the effect of certain non-cash and/or non-recurring items. Adjusted EBITDA is used by management primarily as a measure of our segments' operating performance. Adjusted EBITDA should not be considered an alternative to net income, income from operations, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Because not all companies calculate Adjusted EBITDA identically, our calculation may not be comparable to similarly titled measures of other companies.

Year ended December 31, 2018	Central Appalachia	Northern Appalachia	Rhino Western	Illinois Basin	Other	Total
			(in millions)			
Net income/(loss) from continuing operations	$ 8.8	$ (4.4)	$ 1.4	$ (7.7)	$ (14.1)	$ (16.0)
Plus:						
DD&A	8.7	1.2	4.1	7.9	0.4	22.3
Interest expense	-	-	-	-	8.5	8.5
EBITDA from continuing operations†	$ 17.5	$ (3.2)	$ 5.5	$ 0.2	$ (5.2)	$ 14.8
Plus: Provision for doubtful accounts (1)	0.8	0.1	-	-	-	0.9
Plus: Cumulative effect from adoption of ASU 2016-01 (2)	-	-	-	-	3.7	3.7
Plus: Mark-to-market adjustment -unrealized loss	-	-	-	-	0.2	0.2
Adjusted EBITDA from continuing operations†	18.3	(3.1)	5.5	0.2	(1.3)	19.6
EBITDA from discontinued operations	-	-	-	-	-	-
Adjusted EBITDA †	$ 18.3	$ (3.1)	$ 5.5	$ 0.2	$ (1.3)	$ 19.6

Year ended December 31, 2017	Central Appalachia	Northern Appalachia	Rhino Western	Illinois Basin	Other	Total
			(in millions)			
Net (loss)/income from continuing operations	$ 13.7	$ (3.1)	$ 1.7	$ 1.7	$ (34.6)	$ (20.6)
Plus:						-
DD&A	7.7	1.0	4.4	7.6	0.4	21.1
Interest expense	-	-	-	-	4.0	4.0
EBITDA from continuing operations†	$ 21.4	$ (2.1)	$ 6.1	$ 9.3	$ (30.2)	$ 4.5
Plus: Non-cash asset impairment and other non-cash charges (3)	-	-	0.8	-	21.8	22.6
Adjusted EBITDA from continuing operations†	21.4	(2.1)	6.9	9.3	(8.4)	27.1
EBITDA from discontinued operations	-	(0.8)	-	-	-	(0.8)
Adjusted EBITDA †	$ 21.4	$ (2.9)	$ 6.9	$ 9.3	$ (8.4)	$ 26.3

	For the Year Ended December 31,	
	2018	2017
	(in millions)	
Reconciliation of net cash to Adjusted EBITDA provided by operating activities:		
Net cash provided by operating activities	$ 18.6	$ 14.6
Plus:		
Increase in net operating assets	-	12.1
Gain on sale of assets	3.4	-
Gain on disposal of business	-	3.2
Interest expense	8.5	4.0
Equity in net income of unconsolidated affiliates	-	0.1
Less:		
Decrease in net operating assets	10.2	-
Mark-to-market adjustment – unrealized loss	0.2	-
Amortization of advance royalties	0.6	1.1
Amortization of debt discount	0.4	-
Amortization of debt issuance costs	1.8	1.5
Increase in provision for doubtful accounts	0.9	0.1
Equity-based compensation	0.2	0.3
Loss on asset impairments	-	22.6
Loss on retirement of advance royalties	0.1	0.1
Accretion on asset retirement obligations	1.3	1.5
EBITDA	14.8	6.8
Plus: Non-cash bad debt expense (1)	0.9	0.1
Plus: Non-cash asset impairment and other non-cash charges (3)	-	22.6
Plus: Cumulative effect from adoption of ASU 2016-01 (2)	3.7	-
Plus: Mark-to-market adjustment -unrealized loss	0.2	-
Less: Gain on disposal of business (4)	-	(3.2)
Adjusted EBITDA	19.6	26.3
Less: EBITDA from discontinued operations	-	(0.8)
Adjusted EBITDA from continuing operations	$ 19.6	$ 27.1

† Calculated based on actual amounts and not the rounded amounts presented in this table.

(1) During the year ended December 31, 2018, we recorded provisions for doubtful accounts of approximately $0.9 million, which primarily related to a small number of customers in Central Appalachia.

(2) During the year ended December 31, 2018, the gain recognized from the sales of our TUSK stock was impacted by the adoption of ASU 2016-01, which resulted in $3.7 million of economic benefit being reclassified to equity from Other Comprehensive Income instead of being recognized in net income.

(3) During the year ended December 31, 2017, we recorded asset impairment charges of $22.6 million, including an $0.8 million impairment on land that we own in Mesa County, Colorado and a $21.8 million impairment charge related to the call option received from a third party to acquire substantially of the outstanding common stock of Armstrong Energy, Inc. as discussed earlier.

(4) On November 7, 2017, we closed an agreement with a third party to transfer 100% of the membership interests and related assets and liabilities in Sands Hill Mining LLC as discussed earlier. We recognized a non-cash gain of $3.2 million from the sale of Sands Hill Mining LLC since the third party assumed the reclamation obligations associated with this operation.

We believe that the isolation and presentation of these specific items to arrive at Adjusted EBITDA is useful because it enhances investors' understanding of how we assess the performance of our business. We believe the adjustment of these items provides investors with additional information that they can utilize in evaluating our performance. Additionally, we believe the isolation of these items provides investors with enhanced comparability to prior and future periods of our operating results.

Liquidity and Capital Resources

Liquidity

As of December 31, 2018, our available liquidity was $6.2 million. We also have a delayed draw term loan commitment in the amount of $35 million contingent upon the satisfaction of certain conditions precedent specified in the financing agreement discussed below.

On December 27, 2017, we entered into a Financing Agreement, which provides us with a multi-draw loan in the aggregate principal amount of $80 million. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the financing agreement and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the financing agreement. We used approximately $17.3 million of the net proceeds thereof to repay all amounts outstanding and terminate the Amended and Restated Credit Agreement with PNC Bank. The Financing Agreement terminates on December 27, 2020. For more information about our financing agreement, please read "—Financing Agreement" below.

Our business is capital intensive and requires substantial capital expenditures for purchasing, upgrading and maintaining equipment used in developing and mining our reserves, as well as complying with applicable environmental and mine safety laws and regulations. Our principal liquidity requirements are to finance current operations, fund capital expenditures, including acquisitions from time to time, and service our debt. Historically, our sources of liquidity included cash generated by our operations, cash available on our balance sheet and issuances of equity securities. Our ability to access the capital markets on economic terms in the future will be affected by general economic conditions, the domestic and global financial markets, our operational and financial performance, the value and performance of our equity securities, prevailing commodity prices and other macroeconomic factors outside of our control. Failure to maintain financing or to generate sufficient cash flow from operations could cause us to significantly reduce our spending and to alter our short- or long-term business plan. We may also be required to consider other options, such as selling assets or merger opportunities, and depending on the urgency of our liquidity constraints, we may be required to pursue such an option at an inopportune time.

We continue to take measures, including the suspension of cash distributions on our common and subordinated units and cost and productivity improvements, to enhance and preserve our liquidity so that we can fund our ongoing operations and necessary capital expenditures and meet our financial commitments and debt service obligations.

Cash Flows

Net cash provided by operating activities was $18.6 million for the year ended December 31, 2018 as compared to $14.6 million for the year ended December 31, 2017. This increase in cash provided by operating activities was primarily the result of favorable working capital changes, including the benefit of lowering our inventory with increased coal sales and collections of the related accounts receivable balances.

Net cash used in investing activities was $7.6 million for the year ended December 31, 2018 as compared to net cash used in investing activities of $18.5 million for the year ended December 31, 2017. The decrease in cash used in investing activities was primarily due to proceeds received from the sales of Mammoth Inc. shares during 2018, partially offset by higher capital expenditures in 2018 compared to 2017.

Net cash used in financing activities was $26.0 million for the year ended December 31, 2018, which was primarily attributable to payments on our Financing Agreement, payment of the distribution on the Series A preferred units and deposits required for our workers' compensation and surety programs. Net cash provided by financing activities was $25.0 million for the year ended December 31, 2017, which was primarily due to proceeds from our Financing Agreement partially offset by repayment of our former revolving credit facility.

Capital Expenditures

Our mining operations require investments to expand, upgrade or enhance existing operations and to meet environmental and safety regulations. Maintenance capital expenditures are those capital expenditures required to maintain our long-term operating capacity. For example, maintenance capital expenditures include expenditures associated with the replacement of equipment and coal reserves, whether through the expansion of an existing mine or the acquisition or development of new reserves, to the extent such expenditures are made to maintain our long-term operating capacity. Expansion capital expenditures are those capital expenditures that we expect will increase our operating capacity over the long term. Examples of expansion capital expenditures include the acquisition of reserves, acquisition of equipment for a new mine or the expansion of an existing mine to the extent such expenditures are expected to expand our long-term operating capacity.

Actual maintenance capital expenditures for the year ended December 31, 2018 were approximately $14.2 million. These amounts were primarily used to rebuild, repair or replace older mining equipment. Expansion capital expenditures for the year ended December 31, 2018 were approximately $10.2 million, which were primarily related to the purchase of additional equipment to expand production at one of our Central Appalachia mines. For the year ended December 31, 2019, we have budgeted $13 million to $16 million for maintenance capital expenditures and $2 million to $4 million for expansion capital expenditures.

Financing Agreement

On December 27, 2017, we entered into a Financing Agreement with Cortland Capital Market Services LLC, as Collateral Agent and Administrative agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders therein, pursuant to which Lenders have agreed to provide us with a multi-draw term loan in the aggregate principal amount of $80 million, subject to the terms and conditions set forth in the Financing Agreement. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the Financing Agreement and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement. Loans made pursuant to the Financing Agreement will be secured by substantially all of our assets. The Financing Agreement terminates on December 27, 2020.

Loans made pursuant to the Financing Agreement will, at our option, either be “Reference Rate Loans” or “LIBOR Rate Loans.” Reference Rate Loans bear interest at the greatest of (a) 4.25% per annum, (b) the Federal Funds Rate plus 0.50% per annum, (c) the LIBOR Rate (calculated on a one-month basis) plus 1.00% per annum or (d) the Prime Rate (as published in the Wall Street Journal) or if no such rate is published, the interest rate published by the Federal Reserve Board as the “bank prime loan” rate or similar rate quoted therein, in each case, plus an applicable margin of 9.00% per annum (or 12.00% per annum if we have elected to capitalize an interest payment pursuant to the PIK Option, as described below). LIBOR Rate Loans bear interest at the greater of (x) the LIBOR for such interest period divided by 100% minus the maximum percentage prescribed by the Federal Reserve for determining the reserve requirements in effect with respect to eurocurrency liabilities for any Lender, if any, and (y) 1.00%, in each case, plus 10.00% per annum (or 13.00% per annum if we have elected to capitalize an interest payment pursuant to the PIK Option). Interest payments are due on a monthly basis for Reference Rate Loans and one-, two- or three-month periods, at our option, for LIBOR Rate Loans. If there is no event of default occurring or continuing, we may elect to defer payment on interest accruing at 6.00% per annum by capitalizing and adding such interest payment to the principal amount of the applicable term loan (the “PIK Option”).

Commencing December 31, 2018, the principal for each loan made under the Financing Agreement will be payable on a quarterly basis in an amount equal to $375,000 per quarter, with all remaining unpaid principal and accrued and unpaid interest due on December 27, 2020. In addition, we must make certain prepayments over the term of any loans outstanding, including: (i) the payment of 25% of Excess Cash Flow (as that term is defined in the Financing Agreement) for each fiscal year, commencing with respect to the year ending December 31, 2019, (ii) subject to certain exceptions, the payment of 100% of the net cash proceeds from the dispositions of certain assets, the incurrence of certain indebtedness or receipts of cash outside of the ordinary course of business, and (iii) the payment of the excess of the outstanding principal amount of term loans outstanding over the amount of the Collateral Coverage Amount (as that term is defined in the Financing Agreement). In addition, the Lenders are entitled to certain fees, including 1.50% per annum of the unused Delayed Draw Term Loan Commitment for as long as such commitment exists, (ii) for the 12-month period following the execution of the Financing Agreement, a make-whole amount equal to the interest and unused Delayed Draw Term Loan Commitment fees that would have been payable but for the occurrence of certain events, including among others, bankruptcy proceedings or the termination of the Financing Agreement by us, and (iii) audit and collateral monitoring fees and origination and exit fees.

The Financing Agreement requires us to comply with several affirmative covenants at any time loans are outstanding, including, among others: (i) the requirement to deliver monthly, quarterly and annual financial statements, (ii) the requirement to periodically deliver certificates indicating, among other things, (a) compliance with terms of Financing Agreement and ancillary loan documents, (b) inventory, accounts payable, sales and production numbers, (c) the calculation of the Collateral Coverage Amount (as that term is defined in the Financing Agreement), (d) projections for the business and (e) coal reserve amounts; (ii) the requirement to notify the Administrative Agent of certain events, including events of default under the Financing Agreement, dispositions, entry into material contracts, (iii) the requirement to maintain insurance, obtain permits, and comply with environmental and reclamation laws (iv) the requirement to sell up to $5.0 million of shares in Mammoth Energy Securities, Inc. and use the net proceeds therefrom to prepay outstanding term loans and (v) establish and maintain cash management services and establish a cash management account and deliver a control agreement with respect to such account to the Collateral Agent. The Financing Agreement also contains negative covenants that restrict our ability to, among other things: (i) incur liens or additional indebtedness or make investments or restricted payments, (ii) liquidate or merge with another entity, or dispose of assets, (iii) change the nature of our respective businesses; (iii) make capital expenditures in excess, or, with respect to maintenance capital expenditures, lower than, specified amounts, (iv) incur restrictions on the payment of dividends, (v) prepay or modify the terms of other indebtedness, (vi) permit the Collateral Coverage Amount to be less than the outstanding principal amount of the loans outstanding under the Financing Agreement or (vii) permit the trailing six month Fixed Charge Coverage Ratio to be less than 1.20 to 1.00 commencing with the six-month period ending June 30, 2018.

The Financing Agreement contains customary events of default, following which the Collateral Agent may, at the request of lenders, terminate or reduce all commitments and accelerate the maturity of all outstanding loans to become due and payable immediately together with accrued and unpaid interest thereon and exercise any such other rights as specified under the Financing Agreement and ancillary loan documents.

On April 17, 2018, we amended our Financing Agreement to allow for certain activities, including a sale leaseback of certain pieces of equipment, the extension of the due date for lease consents required under the Financing Agreement to June 30, 2018 and the distribution to holders of the Series A preferred units of $6.0 million (accrued in the consolidated financial statements at December 31, 2017). Additionally, the amendments provided that the Partnership could sell additional shares of Mammoth Inc. stock and retain 50% of the proceeds with the other 50% used to reduce debt. The Partnership reduced its outstanding debt by $3.4 million with proceeds from the sale of Mammoth Inc. stock in the second quarter of 2018.

On July 27, 2018, we entered into a consent with our Lenders related to the Financing Agreement. The consent included the lenders agreement to make a $5 million loan from the Delayed Draw Term Loan Commitment, which was repaid in full on October 26, 2018 pursuant to the terms of the consent. The consent also included a waiver of the requirements relating to the use of proceeds of any sale of the shares of Mammoth Inc. set forth in the consent to the Financing Agreement, dated as of April 17, 2018 and also waived any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended June 30, 2018.

On November 8, 2018, we entered into a consent with our Lenders related to the Financing Agreement. The consent includes the lenders agreement to waive any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended September 30, 2018.

On December 20, 2018, we entered into a limited consent and Waiver to the Financing Agreement. The Waiver relates to our sales of certain real property in Western Colorado, the net proceeds of which are required to be used to reduce our debt under the Financing Agreement. As of the date of the Waiver, we had sold 9 individual lots in smaller transactions. Rather than transmitting net proceeds with respect to each individual transaction, we agreed with the Lenders in principle to delay repayment until an aggregate payment could be made at the end of 2018. On December 18, 2018, we used the sale proceeds of approximately $379,000 to reduce the debt. The Waiver (i) contains a ratification by the Lenders of the sale of the individual lots to date and waives the associated technical defaults under the Financing Agreement for not making immediate payments of net proceeds therefrom, (ii) permits the sale of certain specified additional lots and (iii) subject to Lender consent, permits the sale of other lots on a going forward basis. The net proceeds of future sales will be held by us until a later date to be determined by the Lenders.

On February 13, 2019, we entered into a second amendment to the Financing Agreement. The Amendment provides the Lender's consent for us to pay a one-time cash distribution on February 14, 2019 to the Series A Preferred Unitholders not to exceed approximately $3.2 million. The Amendment allows us to sell our remaining shares of Mammoth Energy Services, Inc. and utilize the proceeds for payment of the one-time cash distribution to the Series A Preferred Unitholders and waives the requirement to use such proceeds to prepay the outstanding principal amount outstanding under the Financing Agreement. The Amendment also waives any Event of Default that has or would otherwise arise under Section 9.01(c) of the Financing Agreement solely by reason of us failing to comply with the Fixed Charge Coverage Ratio covenant in Section 7.03(b) of the Financing Agreement for the fiscal quarter ending December 31, 2018. The Amendment includes an amendment fee of approximately $0.6 million payable by us on May 13, 2019 and an exit fee equal to 1% of the principal amount of the term loans made under the Financing Agreement that is payable on the earliest of (w) the final maturity date of the Financing Agreement, (x) the termination date of the Financing Agreement, (y) the acceleration of the obligations under the Financing Agreement for any reason, including, without limitation, acceleration in accordance with Section 9.01 of the Financing Agreement, including as a result of the commencement of an insolvency proceeding and (z) the date of any refinancing of the term loan under the Financing Agreement. The Amendment amends the definition of the Make-Whole Amount under the Financing Agreement to extend the date of the Make-Whole Amount period to December 31, 2019.

At December 31, 2018, $29.0 million was outstanding under the financing agreement at a variable interest rate of Libor plus 10.00% (12.53% at December 31, 2018).

Common Unit Warrants

We entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. The warrant agreement included the issuance of a total of 683,888 Common Unit Warrants at an exercise price of $1.95 per unit, which was the closing price of our units on the OTC market as of December 27, 2017. The Common Unit Warrants have a five year expiration date. The Common Unit Warrants and the Rhino common units after exercise are both transferable, subject to applicable US securities laws. The Common Unit Warrant exercise price is $1.95 per unit, but the price per unit will be reduced by future common unit distributions and other further adjustments in price included in the warrant agreement for transactions that are dilutive to the amount of Rhino's common units outstanding. The warrant agreement includes a provision for a cashless exercise where the warrant holders can receive a net number of common units. Per the warrant agreement, the warrants are detached from the Financing Agreement and fully transferable.

Letter of Credit Facility – PNC Bank

On December 27, 2017, we entered the LoC Facility Agreement with PNC, pursuant to which PNC agreed to provide us with the LoC Facility. The LoC Facility Agreement provided that we pay a quarterly fee at a rate equal to 5% per annum calculated based on the daily average of letters of credit outstanding under the LoC Facility, as well as administrative costs incurred by PNC and a $100,000 closing fee. The LoC Facility Agreement provided that we reimburse PNC for any drawing under a letter of credit by a specified beneficiary as soon as possible after payment was made. Our obligations under the LoC Facility Agreement were secured by a first lien security interest on a cash collateral account that was required to contain no less than 105% of the face value of the outstanding letters of credit. In the event the amount in such cash collateral account was insufficient to satisfy our reimbursement obligations, the amount outstanding would bear interest at a rate per annum equal to the Base Rate (as that term was defined in the LoC Facility Agreement) plus 2.0%. We would indemnify PNC for any losses which PNC may have incurred as a result of the issuance of a letter of credit or PNC's failure to honor any drawing under a letter of credit, subject in each case to certain exceptions. We provided cash collateral to our counterparties during the third quarter of 2018 and as of September 30, 2018, the LoC Facility was terminated. We had no outstanding letters of credit as of December 30, 2018.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to off-balance sheet arrangements that include guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit and surety bonds. No liabilities related to these arrangements are reflected in our consolidated balance sheet, and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

Federal and state laws require us to secure certain long-term obligations related to mine closure and reclamation costs. We typically secure these obligations by using surety bonds, an off-balance sheet instrument. The use of surety bonds is less expensive for us than the alternative of posting a 100% cash bond or a bank letter of credit. We then provide cash collateral to secure our surety bonding obligations in an amount up to a certain percentage of the aggregate bond liability that we negotiate with the surety companies. To the extent that surety bonds become unavailable, we would seek to secure our reclamation obligations with letters of credit, cash deposits or other suitable forms of collateral.

As of December 31, 2018, we had $8.2 million in cash collateral held by third-parties of which $3.0 million serves as collateral for approximately $42.6 million in surety bonds outstanding that secure the performance of our reclamation obligations. The other $5.2 million serves as collateral for our self-insured workers' compensation program. Of the $42.6 million, approximately $0.4 million relates to surety bonds for Deane Mining, LLC and approximately $3.4 million relates to surety bonds for Sands Hill Mining, LLC, which in each case have not been transferred or replaced by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC as was agreed to by the parties as part of the transactions. We can provide no assurances that a surety company will underwrite the surety bonds of the purchasers of these entities, nor are we aware of the actual amount of reclamation at any given time. Further, if there was a claim under these surety bonds prior to the transfer or replacement of such bonds by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC, then we may be responsible to the surety company for any amounts it pays in respect of such claim. While the buyers are required to indemnify us for damages, including reclamation liabilities, pursuant the agreements governing the sales of these entities, we may not be successful in obtaining any indemnity or any amounts received may be inadequate. See Part I "Business—Regulation and Laws—Surety Bonds."

Critical Accounting Policies and Estimates

Our financial statements are prepared in accordance with accounting principles that are generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities. Management evaluates its estimates and judgments on an on-going basis. Management bases its estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Nevertheless, actual results may differ from the estimates used and judgments made. Note 2 to the consolidated financial statements included elsewhere in this annual report provides a summary of all significant accounting policies. We believe that of these significant accounting policies, the following may involve a higher degree of judgment or complexity.

Property, Plant and Equipment

Property, plant, and equipment, including coal properties, mine development costs and construction costs, are recorded at cost, which includes construction overhead and interest, where applicable. Expenditures for major renewals and betterments are capitalized, while expenditures for maintenance and repairs are expensed as incurred. Mining and other equipment and related facilities are depreciated using the straight-line method based upon the shorter of estimated useful lives of the assets or the estimated life of each mine. Coal properties are depleted using the units-of-production method, based on estimated proven and probable reserves. Mine development costs are amortized using the units-of-production method, based on estimated proven and probable reserves. Gains or losses arising from sales or retirements are included in current operations.

On March 30, 2005, the Financial Accounting Standards Board (FASB) ratified the consensus reached by the Emerging Issues Task Force, or EITF, on accounting for stripping costs in the mining industry. This accounting guidance applies to stripping costs incurred in the production phase of a mine for the removal of overburden or waste materials for the purpose of obtaining access to coal that will be extracted. Under the guidance, stripping costs incurred during the production phase of the mine are variable production costs that are included in the cost of inventory produced and extracted during the period the stripping costs are incurred. We have recorded stripping costs for all of our surface mines incurred during the production phase as variable production costs that are included in the cost of inventory produced. We define a surface mine as a location where we utilize operating assets necessary to extract coal, with the geographic boundary determined by property control, permit boundaries, and/or economic threshold limits. Multiple pits that share common infrastructure and processing equipment may be located within a single surface mine boundary, which can cover separate coal seams that typically are recovered incrementally as the overburden depth increases. In accordance with the accounting guidance for extractive mining activities, we define a mine in production as one from which saleable minerals have begun to be extracted (produced) from an ore body, regardless of the level of production; however, the production phase does not commence with the removal of de minimis saleable mineral material that occurs in conjunction with the removal of overburden or waste material for the purpose of obtaining access to an ore body. We capitalize only the development cost of the first pit at a mine site that may include multiple pits.

Asset Impairments

We follow the accounting guidance on the impairment or disposal of property, plant and equipment, which requires that projected future cash flows from use and disposition of assets be compared with the carrying amounts of those assets when potential impairment is indicated. When the sum of projected undiscounted cash flows is less than the carrying amount, impairment losses are recognized. In determining such impairment losses, we must determine the fair value for the assets in question in accordance with the applicable fair value accounting guidance. Once the fair value is determined, the appropriate impairment loss must be recorded as the difference between the carrying amount of the assets and their respective fair values. Also, in certain situations, expected mine lives are shortened because of changes to planned operations. When that occurs and it is determined that the mine’s underlying costs are not recoverable in the future, reclamation and mine closing obligations are accelerated and the mine closing accrual is increased accordingly. To the extent it is determined that asset carrying values will not be recoverable during a shorter mine life, a provision for such impairment is recognized.

We performed a comprehensive review of our coal mining operations as well as potential future development projects for the year ended December 31, 2018 to ascertain any potential impairment losses. We did not record any impairment losses for coal properties, mine development costs or coal mining equipment and related facilities for the year ended December 31, 2018.

We performed a comprehensive review of our coal mining operations as well as potential future development projects for the year ended December 31, 2017 to ascertain any potential impairment losses. We engaged an independent third party to perform a fair market value appraisal on certain parcels of land that we own in Mesa County, Colorado. The parcels appraised for $6.0 million compared to the carrying value of $6.8 million. We recorded an impairment loss of $0.8 million, which is recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income. No other coal properties, mine development costs or other coal mining equipment and related facilities were impaired as of December 31, 2017.

We also recorded an impairment charge of $21.8 million related to the call option received from a third party to acquire substantially of the outstanding common stock of Armstrong Energy, Inc. On October 31, 2017, Armstrong Energy filed Chapter 11 petitions in the Eastern District of Missouri's United States Bankruptcy Court. Per the Chapter 11 petitions, Armstrong Energy filed a detailed restructuring plan as part of the Chapter 11 proceedings. On February 9, 2018, the U.S. Bankruptcy Court confirmed Armstrong Energy's Chapter 11 reorganization plan and as such we concluded that the call option had no carrying value. An impairment charge of $21.8 million related to the call option has been recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income.

Asset Retirement Obligations

The accounting guidance for asset retirement obligations addresses asset retirement obligations that result from the acquisition, construction, or normal operation of long-lived assets. This guidance requires companies to recognize asset retirement obligations at fair value when the liability is incurred or acquired. Upon initial recognition of a liability, an amount equal to the liability is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. We have recorded the asset retirement costs in Coal properties.

We estimate our future cost requirements for reclamation of land where we have conducted surface and underground mining operations, based on our interpretation of the technical standards of regulations enacted by the U.S. Office of Surface Mining, as well as state regulations. These costs relate to reclaiming the pit and support acreage at surface mines and sealing portals at underground mines. Other reclamation costs are related to refuse and slurry ponds, as well as holding and related termination or exit costs.

We expense contemporaneous reclamation which is performed prior to final mine closure. The establishment of the end of mine reclamation and closure liability is based upon permit requirements and requires significant estimates and assumptions, principally associated with regulatory requirements, costs and recoverable coal reserves. Annually, we review our end of mine reclamation and closure liability and make necessary adjustments, including mine plan and permit changes and revisions to cost and production levels to optimize mining and reclamation efficiency. When a mine life is shortened due to a change in the mine plan, mine closing obligations are accelerated, the related accrual is increased and the related asset is reviewed for impairment, accordingly.

The adjustments to the liability from annual recosting reflect changes in expected timing, cash flow, and the discount rate used in the present value calculation of the liability. Each respective year includes a range of discount rates that are dependent upon the timing of the cash flows of the specific obligations. Changes in the asset retirement obligations for the year ended December 31, 2018 were calculated with discount rates that ranged from 10.6% to 12.1%. Changes in the asset retirement obligations for the year ended December 31, 2017 were calculated with discount rates that ranged from 9.7% to 11.9%. The discount rates changed from previous years due to changes in applicable market indicators that are used to arrive at an appropriate discount rate. Other recosting adjustments to the liability are made annually based on inflationary cost increases or decreases and changes in the expected operating periods of the mines. The related inflation rate utilized in the recosting adjustments was 2.3% for 2018 and 2017.

Workers' Compensation and Pneumoconiosis ("black lung") Benefits

Certain of our subsidiaries are liable under federal and state laws to pay workers' compensation and coal workers' black lung benefits to eligible employees, former employees and their dependents. We currently utilize an insurance program and state workers' compensation fund participation to secure our on-going obligations depending on the location of the operation. Premium expense for workers' compensation benefits is recognized in the period in which the related insurance coverage is provided.

Our black lung benefit liability is calculated using the service cost method that considers the calculation of the actuarial present value of the estimated black lung obligation. The actuarial calculations using the service cost method for our black lung benefit liability are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates.

In addition, our liability for traumatic workers' compensation injury claims is the estimated present value of current workers' compensation benefits, based on actuarial estimates. The actuarial estimates for our workers' compensation liability are based on numerous assumptions including claim development patterns, mortality, medical costs and interest rates.

Revenue Recognition

We adopted ASU 2014-09, Topic 606 on January 1, 2018, using the modified retrospective method. The adoption of Topic 606 had no impact on revenue amounts recorded in our financial statements (See Note 17 to the consolidated financial statements included elsewhere in this annual report for additional discussion). Most of our revenues are generated under coal sales contracts with electric utilities, coal brokers, domestic and non-U.S. steel producers, industrial companies or other coal-related organizations. Revenue is recognized and recorded when shipment or delivery to the customer has occurred, prices are fixed or determinable and the title or risk of loss has passed in accordance with the terms of the sales agreement. Under the typical terms of these agreements, risk of loss transfers to the customers at the mine or port, when the coal is loaded on the rail, barge, truck or other transportation source that delivers coal to its destination. Advance payments received are deferred and recognized in revenue as coal is shipped and title has passed.

Freight and handling costs paid directly to third-party carriers and invoiced separately to coal customers are recorded as freight and handling costs and freight and handling revenues, respectively. Freight and handling costs billed to customers as part of the contractual per ton revenue of customer contracts is included in coal sales revenue.

Other revenues generally consist of coal royalty revenues, coal handling and processing revenues, rebates and rental income. With respect to other revenues recognized in situations unrelated to the shipment of coal, we carefully review the facts and circumstances of each transaction and do not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the seller's price to the buyer is fixed or determinable and collectability is reasonably assured.

Derivative Financial Instruments

We occasionally use diesel fuel contracts to manage the risk of fluctuations in the cost of diesel fuel. Our diesel fuel contracts meet the requirements for the normal purchase normal sale, or NPNS, exception prescribed by the accounting guidance on derivatives and hedging, based on the terms of the contracts and management's intent and ability to take physical delivery of the diesel fuel.

Income Taxes

We are considered a partnership for income tax purposes. Accordingly, the partners report our taxable income or loss on their individual tax returns.

Recent Accounting Pronouncements

Refer to Item 8. Note 2 of the notes to the consolidated financial statements for a discussion of recent accounting pronouncements, which is incorporated herein by reference. There are no known future impacts or material changes or trends of new accounting guidance beyond the disclosures provided in Note 2.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Registrant is a smaller reporting company and is not required to provide this information.

Item 8. Financial Statements and Supplementary Data.

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and notes thereto required for this Item are set forth on pages F-1 to F-28 of this report and are incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

(a) Disclosure Controls and Procedures.

Our principal executive officer (CEO) and principal financial officer (CFO) undertook an evaluation of our disclosure controls and procedures as of the end of the period covered by this report. The CEO and CFO have concluded that our controls and procedures were effective as of December 31, 2018 at the reasonable assurance level. For purposes of this section, the term "disclosure controls and procedures" means controls and other procedures of an issuer that are designed to ensure that information required to be disclosed by the issuer in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

(b) 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 Rule 13a-15(f). Internal control over financial reporting is a process designed under the supervision of our CEO and CFO, and affected by our general partner's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Because of 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.

Under the supervision and with the participation of our management, including the CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting based upon the framework in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework). Based on our evaluation under this framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

(c) Changes in Internal Control Over Financial Reporting.

There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Management of Rhino Resource Partners LP

We are managed and operated by the board of directors and executive officers of our general partner, Rhino GP LLC. Employees of our general partner devote substantially all of their time and effort to our business. As the owner of our general partner, Royal Energy Resources, Inc. ("Royal") has the right to appoint all members of the board of directors of our general partner, including the independent directors. Our unitholders are not entitled to elect our general partner or its directors or otherwise directly participate in our management or operation. Our general partner owes certain fiduciary duties to our unitholders as well as a fiduciary duty to its owners. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Our general partner, therefore, may cause us to incur indebtedness or other obligations that are nonrecourse.

When evaluating a candidate's suitability for a position on the board, the owner of our general partner assesses whether such candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

Executive Officers and Directors

The following table shows information for the executive officers and directors of our general partner as of March 15, 2019:

Name	Age (as of 12/31/2018)	Position With Our General Partner
William Tuorto*	49	Executive Chairman and Chairman of the Board of Directors
Richard A. Boone*	64	President, Chief Executive Officer and Director
Wendell S. Morris*	51	Senior Vice President and Chief Financial Officer
Reford C. Hunt	45	Senior Vice President and Chief Administrative Officer
Whitney C. Kegley*	43	Vice President, Secretary and General Counsel
Brian T. Aug	47	Vice President of Sales
Lazaros Nikeas	42	Director
Douglas Holsted	58	Director
Brian Hughs*	41	Director
Michael Thompson**	49	Director
David Hanig**	43	Director
Bryan H. Lawrence (1)	76	Former Director

* Officers of Royal.
** Independent director.
(1) Mr. Lawrence submitted his resignation as a director of the board of our general partner as of November 4, 2018.

William Tuorto. Mr. Tuorto has served as the Chairman of our general partner's board of directors since March 17, 2016. Mr. Tuorto is the Chairman and Chief Executive Officer of Royal and has been providing legal, financial, and consulting services to public companies for over 20 years. Privately, Mr. Tuorto is an investor and entrepreneur, with holdings in a wide-range portfolio of energy, technology, real estate and hospitality. Mr. Tuorto was awarded a Bachelor of Arts degree from The Citadel in 1991, graduating with honors, and distinguished nominee of the Fulbright Fellowship and Rhodes Scholarship. Mr. Tuorto received his Juris Doctor from the University of South Carolina School of Law in 1995. Mr. Tuorto was selected to serve as a director due to his in-depth business knowledge and investment experience.

Richard A. Boone. Mr. Boone has served as President and Chief Executive Officer of our general partner since December 30, 2016. Prior to December 2016, Mr. Boone served as our President since September 2016 and served as Executive Vice President and Chief Financial Officer since June 2014. Prior to June 2014, Mr. Boone served as Senior Vice President and Chief Financial Officer of our general partner since May 2010, and as Senior Vice President and Chief Financial Officer of Rhino Energy LLC since February 2005. Prior to joining Rhino Energy LLC, he served as Vice President and Corporate Controller of PinnOak Resources, LLC, a coal producer serving the steel making industry, since 2003. Prior to joining PinnOak Resources, LLC, he served as Vice President, Treasurer and Corporate Controller of Horizon Natural Resources Company, a producer of steam and metallurgical coal, since 1998. Effective January 31, 2018, Mr. Boone was appointed as the Chief Executive Officer and principal executive officer of Royal Energy Resources, Inc. ("Royal"), who is the owner of our general partner. Mr. Boone has over 30 years of experience in the coal industry.

Wendell S. Morris. Mr. Morris has served as our general partner's Senior Vice President and Chief Financial Officer since September 2016. From June 2015 to September 2016, Mr. Morris served as our general partner's Vice President of Finance and prior to June 2015, Mr. Morris served as our general partner's Vice President of External Reporting and Investor Relations. Prior to joining Rhino Energy LLC, Mr. Morris was employed by Lexmark International, Inc. where he held various financial and accounting positions. Effective January 31, 2018, Royal appointed Mr. Morris as its Chief Financial Officer and principal financial officer.

Reford C. Hunt. Mr. Hunt joined Rhino Energy, LLC in April 2005 and currently serves as Senior Vice President and Chief Administrative Officer. Mr. Hunt has served in various capacities, including Senior Vice President of Business Development, as well as President of our Rhino Energy WV, LLC, McClane Canyon Mining, LLC and Castle Valley Mining, LLC subsidiaries. Mr. Hunt oversees our business development and exploration projects. Prior to joining Rhino Energy, LLC, he was employed by Sidney Coal Company, a subsidiary of Massey Energy from 1997 to 2005. During his time at Sidney Coal Company as a Mining Engineer, Mr. Hunt oversaw planning, engineering and construction for various mining and preparation operations. Mr. Hunt is a licensed Professional Engineer in Kentucky.

Whitney C. Kegley. Ms. Kegley has served as our general partner's Vice President, Secretary and General Counsel since July 2012. Prior to joining our general partner, and beginning in April 2012, Ms. Kegley served as a partner with the law firm of Dinsmore & Shohl, LLP in their Lexington, KY office. Ms. Kegley concentrated her practice on mergers and acquisitions and general corporate law with an emphasis on mineral and energy law. From March 2009 to April 2012, Ms. Kegley was a member in the Lexington, KY office of McBrayer, McGinnis, Leslie & Kirkland, PLLC, where she concentrated on mergers and acquisitions and general corporate law with an emphasis on mineral and energy law. From August 1999 to March 2009, Ms. Kegley was employed by the law firm of Frost Brown Todd LLC where she held various positions. Effective January 31, 2018, Royal appointed Ms. Kegley as its General Counsel and Secretary.

Brian T. Aug. Mr. Aug has served as our general partner's Vice President of Sales since August 2013. From April 2011 to August 2013, Mr. Aug served as Director of Sales and Marketing for Rhino Energy LLC. Prior to joining Rhino Energy LLC, he was Vice President of Marketing and Trading Analysis for Greenstar Global Energy, a US based corporation focused on the selling of US coals into India. From 1994 until 2010 he worked for Duke Energy Ohio, a Midwest utility with coal and natural gas power generation. The last 10 years of his career at Duke Energy Ohio was spent as Director of Fuels.

Douglas Holsted. Mr. Holsted has served as a director of our general partner since March 17, 2016. Mr. Holsted is the owner of Cox, Holsted & Associates, PC, of Oklahoma City, Oklahoma and was previously the Chief Financial Officer of Royal before resigning from that position on January 31, 2018. He brings more than 25 years' experience in the public sector. Mr. Holsted received his BS in accounting from the University of Central Oklahoma and a Master of Taxation from DePaul University. Mr. Holsted was selected to serve as a director due to his in-depth business knowledge and financial experience.

Brian Hughs. Mr. Hughs has served as a director of our general partner since March 17, 2016. Mr. Hughs is the Vice President and a Director of Royal. Mr. Hughs has been in the private sector as a business owner and entrepreneur since 2001. Through Mr. Hughs' familial involvement in the exploration and production of oil and gas in northern Texas, he brings specialized knowledge and expertise in this field of prospective investments. Mr. Hughs was selected to serve as a director due to his in-depth business knowledge and investment experience.

Michael Thompson. Mr. Thompson has served as a director of our general partner since March 17, 2016. Mr. Thompson is serving as an independent member of the board of directors of the general partner and has been named to the audit and conflicts committee of the board of directors of the general partner. Mr. Thompson manages the WW Strategic Business Development team for HP Incorporated's Managed Services organization. Mr. Thompson is responsible for incubation and initial traction for these businesses and partnerships. Mr. Thompson received a Bachelor's of Arts from Brigham Young University, studying Japanese and Business Management. Prior to HP, Mr. Thompson managed his own consulting business for 12 years and was the president of two publicly-traded oil and gas companies. Mr. Thompson worked for Micron with roles as Director of Commercial Sales, International Operations, and President of Micron Asia. Mr. Thompson was selected to serve as a director due to his in-depth business knowledge and experience.

David Hanig. Mr. Hanig has served as a director of our general partner since March 17, 2016. Mr. Hanig is serving as an independent member of the board of directors of the general partner and has been named to the audit and conflicts committee of the board of directors of the general partner. Mr. Hanig is a managing director at R.W. Pressprich & Co. Mr. Hanig is involved in institutional sales focused on distressed, convertibles, bank loans and reorganization equities. Mr. Hanig was selected to serve as a director due to his in-depth business knowledge and experience.

Lazaros Nikeas. Mr. Nikeas has served as a director of our general partner since November 4, 2018. Mr. Nikeas is an experienced investment and private equity professional who brings over 18 years of corporate finance experience to the Board. Mr Nikeas is currently a Principal investment manager for Weston Energy LLC, a portfolio company of New York private equity group, Yorktown Partners LLC. Prior to this, he was Lead Partner and Principal of Traxys Capital Partners, a private equity vehicle focused on mining, chemicals and industrial investments in partnership with The Carlyle Group. Before moving into private equity, he served as the Head of Corporate Finance Advisory for Materials, Mining and Chemicals for North America for BNP Paribas for five years. Other investment banking roles included Partner in Mergers & Acquisitions Advisory at Hill Street Capital for eight years and as a Corporate Finance Analyst at Morgan Stanley, where he began his career. Altogether, he has advised on over US$25 billion of mergers and acquisitions transactions. Mr Nikeas holds a Bachelor of Arts from Amherst College in Massachusetts, US. Mr. Nikeas was selected to serve as a director due to his in-depth business knowledge and experience.

Director Independence

The board of directors of our general partners has determined that each of Messrs. Thompson and Hanig are independent as defined under the independence standards established by the NYSE and the Exchange Act.

Meetings; Committees of the Board of Directors

The board of directors of our general partner held quarterly meetings during the year ended December 31, 2018. All of the directors serving during 2018 attended each meeting. The board of directors of our general partner has an audit committee, a conflicts committee and a compensation committee.

Audit Committee

The audit committee of our general partner has been established in accordance with the Exchange Act, and consists of Messrs. Thompson and Hanig, both of whom are independent. Our audit committee operates pursuant to a written charter, an electronic copy of which is available on our website at http://www.rhinolp.com. This committee oversees, reviews, acts on and reports to our board of directors of our general partner on various auditing and accounting matters, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements.

Compensation Committee

The compensation committee of our general partner consists of Messrs. Tuorto, Boone and Hughs and operates pursuant to a written charter. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. The compensation committee also administers our incentive compensation and benefit plans.

Conflicts Committee

Messrs. Thompson and Hanig serve on the conflicts committee to review specific matters that the board believes may involve conflicts of interest and determine to submit to the conflicts committee for review. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be directors, officers or employees of our general partner or any person controlling our general partner and must meet the independence standards established by the Exchange Act to serve on an audit committee of a board of directors, along with other requirements in our partnership agreement. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

Executive Sessions of Non-Management Directors; Procedure for Contacting the Board of Directors

The board of directors of our general partner has held regular executive sessions in which the two independent directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the independent directors.

A means for interested parties to contact the board of directors (including the independent directors as a group) directly has been established in the general partner's Corporate Governance Guidelines, published on our website at *www.rhinolp.com*. Information may be submitted confidentially and anonymously, although we may be obligated by law to disclose the information or identity of the person providing the information in connection with government or private legal actions and in certain other circumstances.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics that applies to all of our officers, directors and employees. An electronic copy of the code is available on our website at http://www.rhinolp.com. For a discussion on what other corporate governance materials are posted on our website, see Part I, Item 1. "Business—Available Information." We intend to disclose any amendments to, or waivers from, our Code of Business Conduct and Ethics that apply to our principal executive officer, principal financial officer, and principal accounting officer or controller on our website promptly following the date of any such amendment or waiver.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, executive officer and persons who beneficially own more than 10% of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Based upon a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that, during the year ended December 31, 2018, none of our executive officers, directors or beneficial owners of more than 10% of any class of registered equity security failed to file on a timely basis any such report, except as described below.

The Form 4 reports relating to the granting of Partnership units to Messrs. Tuorto, Boone, Hughs, Holsted, Hanig, Thompson and Phillips on May 8, 2018 were filed after the applicable due date. The Form 4 reports relating to the market purchases of Partnership units on December 6, 2018 and December 7, 2018 by Mr. Tuorto were filed after the applicable due date.

Item 11. Executive Compensation

Introduction

For 2018, we are reporting as a smaller reporting company due to our market capitalization. In accordance with such rules, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures with respect to our named executive officers. Further, our reporting obligations extend only to the individuals serving as our chief executive officer and our two other most highly compensated executive officers.

Our general partner has the sole responsibility for conducting our business and for managing our operations, and its board of directors and officers make decisions on our behalf. The compensation committee of the board of directors of our general partner determines the compensation of the directors and officers of our general partner, including its named executive officers. The compensation payable to the officers of our general partner is paid by our general partner and reimbursed by us on a dollar-for-dollar basis.

In 2018, the named executive officers of our general partner were:

- William Tuorto—Executive Chairman and Chairman of our Board of Directors;
- Richard A. Boone—President, Chief Executive Officer and Director;
- Reford C. Hunt— Senior Vice President and Chief Administrative Officer.

With respect to the compensation disclosures and the tables that follow, these individuals are referred to as the "named executive officers."

Summary Compensation Table

The following table sets forth the cash and other compensation earned by each of our named executive officers for the years ended December 31, 2018 and 2017.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($) (2)	Unit Awards ($) (3)	All Other Compensation ($)(4)	Total ($)
William Tuorto	2018	455,000	217,500	31,251	11,000	714,751
Executive Chairman and Director	2017	318,077	200,000	31,250	10,800	560,127
Richard A. Boone	2018	300,000	30,000	31,251	14,106	375,357
President, Chief Executive Officer and Director	2017	300,000	200,000	31,250	14,092	545,342
Reford C. Hunt	2018	298,077	-	-	15,716	313,793
Vice President and Chief Administrative Officer	2017	287,923	30,000	-	12,502	330,425

(1) The salary column also reflects $20,000 in director fees paid to Mr. Tuorto with respect to the 2018 year. Further details regarding our director compensation program is provided below.

(2) For each individual, the bonus amount reflects the annual cash bonus awarded to each of the named executive officers per the terms of their employment agreements, which are described further below.

(3) The amounts reported in the "Unit Awards" column reflect the aggregate grant date fair value of awards granted under the Rhino Long-Term Incentive Plan (the "LTIP"), computed in accordance with FASB ASC Topic 718. All phantom unit awards granted during the 2016 year were fully vested on the date of grant. We did not grant equity awards to our named executive officers during the 2018 year in their employee capacity, although Messrs. Tuorto and Boone received an equity award for their services on our Board during the 2018 fiscal year. Further details regarding our director compensation program is provided below.

(4) Amounts reflect, as applicable with respect to the named executive officers and as provided in the supplemental table below, the use of a company provided automobile and employer contributions to the 401(k) Plan. The value of automobile use is calculated as the monthly lease payment paid by us on behalf of the executive multiplied by the monthly percentage of personal use of the automobile by the executive.

Name	Automobile Use	Employer Contribution to Rhino 401(k) Plan
William Tuorto	$ -	$ 11,000
Richard A. Boone	3,106	11,000
Reford C. Hunt	4,716	11,000

Narrative Discussion of Summary Compensation Table

Employment Agreements

We have entered into employment agreements with each of the named executive officers, except for Mr. Boone whose employment agreement expired December 31, 2018. Our employment agreements may be terminated earlier in accordance with the terms of the applicable agreement or extended by mutual agreement of the parties. We entered into an employment agreement amendment with Mr. Tuorto effective January 1, 2018 that increased his annual base salary to $435,000 for 2018. Messrs. Boone and Hunt received an annual base salary of $300,000 for 2018. Although our annual bonus program is ultimately a discretionary bonus program, the named executive officers' employment agreements set forth guidelines and general target amounts for each executive based on a percentage of base salary. The target bonus percentage for Messrs. Tuorto, Boone and Hunt was 100%, 100% and 40%, respectively. We did not enter into any amendments of Messrs. Boone's and Hunt's existing employment agreements during the 2018 year. Effective January 1, 2019, we entered into an employment agreement amendment with Mr. Hunt to extend his employment period to December 31, 2019.

The named executive officers are eligible to participate in our employee benefit programs made available to similarly situated employees. Pursuant to their respective employment agreements, we provide Messrs. Boone and Hunt with automobiles suitable for their duties and responsibilities to us.

The severance and change in control benefits provided by the employment agreements with the named executive officers are described below in the section titled "—Potential Payments Upon Termination or Change in Control—Employment Agreements." The employment agreements also contain certain confidentiality, noncompetition, and other restrictive covenants, which are also described in the section titled "—Potential Payments Upon Termination or Change in Control—Employment Agreement."

Unit and Phantom Unit Awards

Certain named executives received discretionary awards of phantom units years prior to 2016 in respect of the prior fiscal year's performance. These phantom unit awards were designed to vest in equal annual installments over a 36-month period (i.e., approximately 33.3% vest at each annual anniversary of the date of grant), provided the named executive officer remained an employee continuously from the date of grant through the applicable vesting date. The phantom units were designed to become fully vested upon a change in control or in the event that the named executive officer's employment was terminated due to disability or death. In addition, if the named executive officer's employment was terminated by us without cause or by the executive for good reason, the vesting of those phantom units scheduled to vest in the 12 month period following such termination would have been accelerated to the officer's termination date. While a named executive officer holds unvested phantom units, he is entitled to receive DER credits that will be paid in cash upon vesting of the associated phantom units (and will be forfeited at the same time the associated phantom units are forfeited). No phantom units were held the named executive officers during 2018 or 2017.

Outstanding Equity Awards at Fiscal Year End

Our named executives did not have any outstanding equity awards as of December 31, 2018.

Potential Payments Upon Termination or Change in Control

We have employment agreements with each of the named executive officers that contain provisions regarding payments to be made to such individuals upon an involuntary termination of their employment by us without "cause" or their resignation for "good reason."

Employment Agreements

Under the employment agreements with Messrs. Tuorto, Boone and Hunt, if the employment of the executive is terminated by us for "cause," by the executive voluntarily without "good reason," or due to the executive's "disability," then the executive, as applicable, will be entitled to receive his earned but unpaid base salary, payment with respect to accrued but unpaid vacation days, all benefits accrued and vested under any of our benefit plans, and reimbursement for any properly incurred business expenses (collectively, the "accrued obligations"). In addition to the foregoing, in the event the employment of Messrs. Tuorto or Boone is terminated by us without "cause" or by the executive for "good reason," Messrs. Tuorto and Boone shall receive their base salary for the period from termination through the expiration of their respective employment agreements, subject to the executive's timely execution and delivery (and non-revocation) of a release agreement for our benefit. In the event of the death of Mr. Tuorto or Boone, their estate will be entitled to receive the accrued obligations and a pro-rated annual discretionary bonus.

Messrs. Tuorto and Boone are subject to certain confidentiality, non-compete and non-solicitation provisions contained in their employment agreements. The confidentiality covenants are perpetual, while the non-compete and non-solicitation covenants apply during the term of their employment agreements and for one year (two years for non-solicitation) following Messrs. Tuorto's and Boone's termination for any reason. Mr. Tuorto's employment agreement acknowledges his position and employment with Royal and specifically excepts his non-compete provision as it relates to Royal and its affiliates.

For purposes of the employment agreements with Messrs. Tuorto and Boone, the terms listed below have been defined as follows:

- "cause" means (a) failure of the executive to perform substantially his duties (other than a failure due to a "disability") within ten days after written notice from us, (b) executive's conviction of, or plea of guilty or no contest to a misdemeanor involving dishonesty or moral turpitude or any felony, (c) executive engaging in any illegal conduct, gross misconduct, or other material breach of the employment agreement that is materially and demonstratively injurious to us or (d) executive engaging in any act of dishonesty or fraud involving us or any of our affiliates.

- "disability" means the inability of executive to perform his normal duties as a result of a physical or mental injury or ailment for any consecutive 45 day period or for 90 days (whether or not consecutive) during any 365 day period.

- "good reason" means, without the executive's express written consent, (a) the assignment to the executive of duties inconsistent in any material respect with those of the executive's position (including status, office, title, and reporting requirements), or any other diminution in any material respect in such position, authority, duties or responsibilities, (b) a reduction in base salary, (c) a reduction in the executive's welfare, qualified retirement plan or paid time off benefits, other than a reduction as a result of a general change in any such plan or (d) any purported termination of the executive's employment under the employment agreement other than for "cause," death or "disability". The executive must give notice of the event alleged to constitute "good reason" within six months of its occurrence and we have 30 days upon receipt of the notice to cure the alleged "good reason" event.

Under the employment agreement with Mr. Hunt, if his employment is terminated by us without "cause" or if Mr. Hunt resigns for "good reason", which such term has the same meaning as described above with respect to the employment agreements with Messrs. Tuorto and Boone, Mr. Hunt is entitled to receive a lump sum payment equal to twelve months' worth of his base salary and continued family health insurance, at the same premium cost as was in effect on the date of termination, until the earlier of twelve months or the date he becomes covered under a new employer's plan, subject to the executive's timely execution and delivery (and non-revocation) of a release agreement for our benefit. Mr. Hunt is subject to certain confidentiality, non-compete and non-solicitation provisions contained in his employment agreement. The confidentiality covenants are perpetual, while the non-compete covenants apply during the terms of his employment agreements and for one year following termination of employment. The non-solicitation period runs until the end of the six month period following the end of the applicable non-compete period. In the event of the death of Mr. Hunt, his estate will be entitled to receive the accrued obligations and a pro-rated annual discretionary bonus.

For purposes of the agreements with Mr. Hunt, "cause" means (a) the commission by executive of an act of dishonesty or fraud against us, (b) a breach of the executive's obligations under the employment agreement and failure to cure such breach within ten days after written notice from us, (c) executive is indicted for or convicted of a crime involving moral turpitude or (d) executive materially fails or neglects to diligently perform his duties and "disability".

Following the 2017 year, in connection with his appointment as its Chief Executive Officer and principal executive officer, Mr. Boone entered into an employment agreement with Royal. The Royal employment agreement provides Mr. Boone with an annual base salary of $50,000, and states that Mr. Boone will be expected to allocate his business time to Royal and to us in proportion to the base salary he is paid at each entity. We amended our employment agreement with Mr. Boone to allow him to serve as Royal's Chief Executive Officer.

LTIP Phantom Unit Awards

Messrs. Boone and Hunt have periodically held awards of phantom units as previously described in the section above titled "—Narrative Discussion of Summary Compensation Table—Phantom Unit Awards," although as of December 31, 2018 none of our named executive officers held outstanding phantom unit awards.

Our phantom units are typically designed to accelerate vesting in full upon a "change of control" or the named executive officer's termination due to death or "disability." In addition, upon a termination of the executive by us without cause or by the executive for a good reason, the vesting of those phantom units scheduled to vest in the 12-month period following such termination will be accelerated to such termination date. For this purpose, "good reason" and "cause" have the meanings set forth in the respective employment agreements of the named executive officers described above. A "change of control" will be deemed to have occurred if: (i) any person or group, our general partner or an affiliate of either, becomes the owner of more than 50% of the voting power of the voting securities of either us or our general partner; or (ii) upon the sale or other disposition by either us or our general partner of all or substantially all of its assets, whether in a single or series of related transactions, to one or more parties, our general partner or an affiliate of either. A "disability" is any illness or injury for which the named executive officer will be entitled to benefits under the long-term disability plan of our general partner.

Director Compensation

We provide compensation to the directors of the board of directors of our general partner, including a $20,000 annual base director fee and a grant of that number of common units having a grant date value of approximately $31,250 (except for a value of $62,500 for our independent directors) based on the preceding 10-day average price per unit). In addition, the chairs of the audit committee and conflicts committee receive a $15,000 fee, the chair of any other committee (including the compensation committee) receives a $10,000 fee, audit committee and conflicts committee members receive a $10,000 fee and the other committee members receive a $5,000 fee, for their service in such roles each year. Each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees, and each director is fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law.

The following table provides information concerning the compensation of our directors for the fiscal year ended December 31, 2018. All compensation for fiscal year 2018 provided to Messrs. Tuorto and Boone in their capacity as directors has been reflected within the Summary Compensation Table above.

Name	Fees Earned or Paid in Cash ($)(1)	Unit Awards ($)(2)	Total ($)
Brian Hughs	$ 20,000	$ 31,250	$ 51,250
Douglas Holsted	$ 20,000	$ 31,250	$ 51,250
Michael Thompson	$ 50,000	$ 62,500	$ 112,500
David Hanig	$ 40,000	$ 62,500	$ 102,500

(1) Includes annual base director fee, committee membership fees, and committee chair fees for each non-employee director as more fully explained in the preceding paragraphs.

(2) The amounts reported in the "Unit Awards" column reflect the aggregate grant date fair value of the awards granted in fiscal 2018, computed in accordance with FASB ASC Topic 718. See Note 2 to our consolidated financial statements for additional detail regarding assumptions underlying the value of these equity awards.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.

The following table sets forth the beneficial ownership of common units, subordinated units and Series A preferred units as of March 15, 2019 of Rhino Resource Partners LP for:

- beneficial owners of more than 5% of our common, subordinated and Series A preferred units;
- each director, director nominee and named executive officer; and
- all of our directors and executive officers as a group.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Series A Preferred Beneficially Owned	Percentage of Series A preferred units Beneficially Owned
Royal Energy Resources, Inc.(1) (2) (3)	6,468,873	49.4%	1,065,666	93.2%	—	—
Weston Energy LLC (4)	—	—	—	—	1,400,000	93.3%
Thomson Family Limited Partnership (5)	—	—	—	—	50,000	3.3%
John L. Thomson (5)	—	—	—	—	50,000	3.3%
William Tuorto(1)(3)	6,579,072	50.2%	1,065,666	93.2%	—	—
Brian Hughs(1)(3)	6,502,763	49.6%	1,065,666	93.2%	—	—
Rhino Resource Partners Holdings (4)	5,000,000	38.2%	—	—	—	—
Douglas Holsted (6)	33,890	*	—	—	—	—
Richard A. Boone (6)	68,521	*	—	—	—	—
Reford C. Hunt (6)	—	—	—	—	—	—
Michael Thompson (6)	67,779	*	—	—	—	—
David Hanig (6)	43,577	*	—	—	—	—
Lazaros Nikeas (6)	7,776	—	—	—	—	—
All executive officers and directors as a group (8 persons)	6,834,505	52.2%	1,065,666	93.2%		

* Represents less than 1% of the total.

(1) 6,468,873 common units and 1,065,666 of the subordinated units shown as beneficially owned by each of William Tuorto and Brian Hughs, reflect common units and subordinated units owned of record by Royal. Messrs. Tuorto and Hughs serve as directors of Royal and as such may be deemed to share beneficial ownership of the units beneficially owned by Royal, but disclaims such beneficial ownership to the extent such beneficial ownership exceeds its pecuniary interests.

(2) Royal has 5,000,000 Rhino units pledged as collateral for a note payable of $2.5 million.

(3) The address for this person or entity is 56 Broad Street, Suite 2, Charleston, South Carolina 29401.

(4) The address for this person or entity is 410 Park Avenue, 19th Floor, New York, New York 10022.

(5) The address for this person or entity is 410 Park Avenue, 7th Floor, New York, New York 10022.

(6) The address for this person or entity is 424 Lewis Hargett Circle, Suite 250, Lexington, Kentucky 40503.

Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of December 31, 2016 (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of units remaining available for future issuance under equity compensation plans as of December 31, 2018 (excluding units reflected in column (a)) (c)
Equity compensation plans not approved by unitholders(1):			
Long-Term Incentive Plan	-	n/a(2)	12,996

(1) Adopted by the board of directors of our general partner in connection with our IPO.
(2) To date, only phantom and restricted and unrestricted units have been granted under the Long-Term Incentive Plan.

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

On January 21, 2016, a definitive agreement was completed between Royal and Wexford whereby Royal acquired 676,912 of our common units from Wexford. Pursuant to the definitive agreement, on March 17, 2016, Royal acquired all of the issued and outstanding membership interests of Rhino GP LLC, our general partner, as well as 945,525 of the subordinated units from Wexford. Our general partner owns the general partner interest in us as well as our incentive distribution rights. On March 21, 2016, we issued 6,000,000 common units to Royal in a private placement. On December 30, 2016, Royal acquired 200,000 shares of Series A preferred units representing preferred interests in the Partnership.

William Tuorto, Douglas Holsted and Brian Hughs, each a director of our general partner, own an equity interest in Royal. Mr. Tuorto holds all of the Series A Preferred Stock in Royal and a majority of the common stock in Royal. Because of the special voting rights of the Series A Preferred Stock (which is entitled to 54% of the total votes on any matter on which shareholders have a right to vote) of Royal, as of March 15, 2019, Mr. Tuorto controlled 75.6% of the votes on any matter requiring a vote of the Royal shareholders. Mr. Hughs also holds common stock in Royal.

The terms of the transactions and agreements disclosed in this section were determined by and among affiliated entities and, consequently, are not the result of arm's length negotiations. Such terms are not necessarily at least as favorable to the parties to these transactions and agreements as the terms which could have been obtained from unaffiliated third parties.

Agreements with Affiliates

Registration Rights

Under our partnership agreement, as amended and restated, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units or other limited partner interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

Transactions with Royal

On December 5, 2017, we entered into a Coal Sales Fee Agency Agreement (the "Agency Agreement") with Royal, under which Royal acts as a non-exclusive agent to us to procure coal buyers for coal produced by us. Under the Agency Agreement, we are obligated to pay Royal $0.25 for every short ton of steam coal and $1.50 for every ton of metallurgical coal (except $0.50 per ton for one buyer) loaded and sold pursuant to a sales contract procured by Royal. The Agency Agreement provides that our obligation to pay fees in relation to coal sold to a buyer introduced by Royal will extend in perpetuity, unless the buyer does not purchase any coal from us for two consecutive years. The Agency Agreement further provides that Royal has the right, with our consent, to convert any fees due to Royal into our common units at a price equal to seventy-five percent (75%) of the volume weighted average price of the common units for the ninety (90) trading days preceding the date of conversion. By its terms, the Agency Agreement did not become effective until we refinanced our indebtedness with PNC Bank, N.A., which occurred on December 27, 2017. In the year ended December 31, 2018, we paid Royal approximately $0.6 million in fees earned under the Agency Agreement, which included coal sold to buyers introduced by us prior to the effective date of the Agency Agreement. An extension of the Coal Sales Fee Agency Agreement was signed in December 2018 and extends the agreement until December 31, 2019.

On December 5, 2017, we entered into a Guaranty Fee and Indemnity Agreement (the "Guaranty Agreement") with Royal, under which Royal acts as a guarantor of our obligations under any surety bond issued for the benefit of us by Indemnity National Insurance Company ("INIC"). In consideration for the guaranty, we are obligated to pay Royal one percent (1%) of the face value of the surety bond per year. The Guaranty Agreement has a term of three years. The Guaranty Agreement provides that, until Royal's liability under the guaranty to INIC is extinguished, we are obligated to issue Royal additional common units sufficient to ensure that Royal's ownership of our common units does not fall below 10% of the issued and outstanding common units at the time. The Guaranty Agreement further provides that Royal has the right, with our consent, to convert any fees due to Royal into our common units at a price equal to seventy-five percent (75%) of the volume weighted average price of the common units for the ninety (90) trading days preceding the date of conversion. By its terms, the Guaranty Agreement did not become effective until we refinanced our indebtedness with PNC Bank, N.A., which occurred on December 27, 2017. In the year ended December 31, 2017, we paid Royal two payments of $364,917 each, one of which represented amounts due under the Guaranty Agreement for 2017 and the other was for amounts that were due under the Guaranty Agreement in 2018.

Series A Preferred Unit Purchase Agreement

On December 30, 2016, we entered into the Series A Preferred Unit Purchase Agreement with Weston, an entity wholly owned by certain investment partnerships managed by Yorktown, and Royal. Under the Preferred Unit Agreement, Weston and Royal agreed to purchase 1,300,000 and 200,000, respectively, of Series A preferred units representing limited partner interests in us at a price of $10.00 per Series A preferred unit. The Series A preferred units have the preferences, rights and obligations set forth in the Fourth Amended and Restated Agreement of Limited Partnership, which is described below. In exchange for the Series A preferred units, Weston and Royal paid cash of $11.0 million and $2.0 million, respectively, to us and Weston assigned to us the $2.0 million Weston Promissory Note from Royal originally dated September 30, 2016. Please read "—Letter Agreement Regarding Rhino Promissory Note and Weston Promissory Note."

The Preferred Unit Agreement contains customary representations, warrants and covenants, which include among other things, that, for as long as the Series A preferred units are outstanding, we will cause CAM Mining, one of our subsidiaries, to conduct its business in the ordinary course consistent with past practice and use reasonable best efforts to maintain and preserve intact its current organization, business and franchise and to preserve the rights, franchises, goodwill and relationships of its employees, customers, lenders, suppliers, regulators and others having business relationships with CAM Mining.

The Preferred Unit Agreement stipulates that upon the request of the holder of the majority of our common units following their conversion from Series A preferred units, as outlined in our partnership agreement, we will enter into a registration rights agreement with such holder. Such majority holder has the right to demand two shelf registration statements and registration statements on Form S-1, as well as piggyback registration rights.

Fourth Amended and Restated Partnership Agreement of Limited Partnership

On December 30, 2016, our general partner entered into the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership ("Amended and Restated Partnership Agreement") to create, authorize and issue the Series A preferred units.

The Series A preferred units are a new class of equity security that rank senior to all classes or series of our equity securities with respect to distribution rights and rights upon liquidation. The holders of the Series A preferred units are entitled to receive annual distributions equal to the greater of (i) 50% of the CAM Mining free cash flow (as defined below) and (ii) an amount equal to the number of outstanding Series A preferred units multiplied by $0.80. "CAM Mining free cash flow" is defined in our partnership agreement as (i) the total revenue of our Central Appalachia business segment, minus (ii) the cost of operations (exclusive of depreciation, depletion and amortization) for our Central Appalachia business segment, minus (iii) an amount equal to $6.50, multiplied by the aggregate number of met coal and steam coal tons sold by us from our Central Appalachia business segment. If we fail to pay any or all of the distributions in respect of the Series A preferred units, such deficiency will accrue until paid in full and we will not be permitted to pay any distributions on our partnership interests that rank junior to the Series A preferred units, including our common units. The Series A preferred units will be liquidated in accordance with their capital accounts and upon liquidation will be entitled to distributions of property and cash in accordance with the balances of their capital accounts prior to such distributions to equity securities that rank junior to the Series A preferred units.

The Series A preferred units vote on an as-converted basis with the common units, and we will be restricted from taking certain actions without the consent of the holders of a majority of the Series A preferred units, including: (i) the issuance of additional Series A preferred units, or securities that rank senior or equal to the Series A preferred units; (ii) the sale or transfer of CAM Mining or a material portion of its assets; (iii) the repurchase of common units, or the issuance of rights or warrants to holders of common units entitling them to purchase common units at less than fair market value; (iv) consummation of a spin off; (v) the incurrence, assumption or guaranty of indebtedness for borrowed money in excess of $50.0 million except indebtedness relating to entities or assets that are acquired by us or our affiliates that is in existence at the time of such acquisition or (vi) the modification of CAM Mining's accounting principles or the financial or operational reporting principles of our Central Appalachia business segment, subject to certain exceptions.

We have the option to convert the outstanding Series A preferred units at any time on or after the time at which the amount of aggregate distributions paid in respect of each Series A preferred unit exceeds $10.00 per unit. Each Series A preferred unit will convert into a number of common units equal to the quotient (the "Series A Conversion Ratio") of (i) the sum of $10.00 and any unpaid distributions in respect of such Series A Preferred Unit divided by (ii) 75% of the volume weighted average closing price of the common units for the preceding 90 trading days (the "VWAP"); provided however, that the VWAP will be capped at a minimum of $2.00 and a maximum of $10.00. On December 31, 2021, all outstanding Series A preferred units will convert into common units at the then applicable Series A Conversion Ratio.

Letter Agreement Regarding Rhino Promissory Note and Weston Promissory Note

On December 30, 2016, we entered into a letter agreement with Royal whereby the maturity dates of the Weston Promissory Note and the final installment payment of the Rhino Promissory Note were extended to December 31, 2018. The letter agreement further provided that the aggregate $4.0 million balance of the Weston Promissory Note and Rhino Promissory Note may be converted at Royal's option into a number of shares of Royal's common stock equal to the outstanding balance multiplied by seventy-five percent (75%) of the volume-weighted average closing price of Royal's common stock for the 90 days preceding the date of conversion ("Royal VWAP"), subject to a minimum Royal VWAP of $3.50 and a maximum Royal VWAP of $7.50. On September 1, 2017, Royal elected to convert the Rhino Promissory Note and the Weston Promissory Note to shares of Royal common stock. Royal issued 914,797 shares of its common stock to us at a conversion price of $4.51 as calculated per the method stipulated above. We recorded the $4.1 million conversion of the Weston Promissory Note and Rhino Promissory Note as Investment in Royal common stock in the Partners' Capital section of our consolidated statements of financial position.

Policies Relating to 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 on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners. At the same time, our general partner has a contractual duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that replace default fiduciary duties under applicable Delaware law with contractual corporate governance standards. Our partnership agreement also delimits the remedies available to our unitholders for actions taken by our general partner that, without those limitations, might constitute breaches of its default fiduciary duty under applicable Delaware law.

Our general partner will not be in breach of its obligations under our partnership agreement or its duties or obligations to us or our unitholders if the resolution of the conflict is:

- approved by the conflicts committee of our general partner, although our general partner is not obligated to seek such approval;

- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;

- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. In connection with a situation involving a conflict of interest, any determination by our general partner involving the resolution of the conflict of interest must be made in good faith, provided that, if our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors that it determines in good faith to be appropriate when resolving a conflict. When our partnership agreement provides that someone act in good faith, it requires that person to reasonably believe he is acting in the best interests of the partnership.

Director Independence

See "Part III, Item 10. Directors, Executive Officers and Corporate Governance" for information regarding the directors of our general partner and the independence requirements applicable to the board of directors of our general partner and its committees.

Item 14. Principal Accounting Fees and Services.

The following table presents fees for professional services provided by Brown Edwards & Company, L.L.P. for the years 2018 and 2017:

	2018	2017
	(in thousands)	
Audit fees	$ 347	$ 339
Audit related fees	-	-
Tax fees	-	-
Total	$ 347	$ 339

Our audit committee has adopted an audit committee charter, which is available on our website, which requires the audit committee to pre-approve all audit and non-audit services to be provided by our independent registered public accounting firm. The audit committee does not delegate its pre-approval responsibilities to management or to an individual member of the audit committee. All fees reported above were pre-approved by the audit committee as required.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

See "Index to the Consolidated Financial Statements" set forth on Page F-1.

(2) Financial Statement Schedules

All schedules are omitted because they are not applicable or the required information is presented in the financial statements or notes thereto.

Item 16. Form 10-K Summary.

None.

(3) Exhibits

EXHIBIT LIST

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Rhino Resource Partners LP, incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-166550) filed on May 5, 2010
3.2	Fourth Amended and Restated Agreement of Limited Partnership of Rhino Resource Partners LP, dated as of December 30, 2016, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-34892) filed on January 6, 2017
3.3	Amendment No. 1 to the Fourth Amended and Restated Agreement of Limited Partnership of Rhino Resource Partners LP, dated January 25, 2018, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-34892) filed on January 25, 2018
4.1	Registration Rights Agreement, dated as of March 21, 2016, by and between Rhino Resource Partners LP and Royal Energy Resources, Inc., incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-34892) filed on March 23, 2016
10.1	Consent to Financing Agreement dated as of April 17, 2018, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34982) filed on April 23, 2018
10.2	Consent to Financing Agreement dated as of July 27, 2018, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34982) filed on July 31, 2018.
10.3	First Amendment to Financing Agreement dated as of November 8, 2018, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent, incorporated by reference to Exhibit 10.2 on Form 10-Q (File No. 001-34982) filed on November 9, 2018.
10.4	Limited Waiver and Consent to Financing Agreement dated as of December 20, 2018, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34982) filed on December 28, 2018.
10.5	Second Amendment to Financing Agreement dated as of February 13, 2019, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34982) filed on February 15, 2019.
10.6†*	Amended and Restated Employment Agreement of Reford C. Hunt effective January 1, 2019
10.7†*	Amended and Restated Employment Agreement of Wendell S. Morris effective January 1, 2019
10.8†*	Amended and Restated Employment Agreement of Brian T. Aug effective January 1, 2019

10.9†	Rhino Long-Term Incentive Plan incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34892) filed on October 1, 2010
10.10†	Form of Long-Term Incentive Plan Grant Agreement—Phantom Units with DERs, incorporated by reference to Exhibit 10.12 of Amendment No. 3 to the Registration Statement on Form S-1 (File No. 333-166550) filed on July 23, 2010

Exhibit Number	Description
21.1*	List of Subsidiaries of Rhino Resource Partners LP
23.1*	Consent of Brown, Edwards and Company L.L.P
23.2*	Consent of Marshall Miller and Associates, Inc.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)
32.1*	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)
32.2*	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)
95.1*	Mine Health and Safety Disclosure pursuant to §1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act for the year ended December 31, 2018
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed or furnished herewith, as applicable.

† Management contract or compensatory plan or arrangement required to be filed as an exhibit to this 10-K pursuant to Item 15(b).

** Schedules and similar attachments have been omitted pursuant to Item 601(b)(2) of Regulation S K. The registrant undertakes to furnish supplementally copies of any of the omitted schedules and exhibits upon request by the Securities and Exchange Commission.

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.

RHINO RESOURCE PARTNERS LP

By: Rhino GP LLC, its general partner

By: */s/ RICHARD A. BOONE*
Richard A. Boone
President, Chief Executive Officer and Director

Date: March 25, 2019

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.

Signature	Title	Date
/s/ Richard A. Boone Richard A. Boone	President, Chief Executive Officer and Director (Principal Executive Officer)	March 25, 2019
/s/ Wendell S. Morris Wendell S. Morris	Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 25, 2019
/s/ WILLIAM TUORTO William Tuorto	Director	March 25, 2019
/s/ Lazaros Nikeas Lazaros Nikeas	Director	March 25, 2019
/s/ DOUGLAS HOLSTED Douglas Holsted	Director	March 25, 2019
/s/ BRIAN HUGHS Brian Hughs	Director	March 25, 2019
/s/ Michael Thompson Michael Thompson	Director	March 25, 2019
/s/ DAVID HANIG David Hanig	Director	March 25, 2019

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RHINO RESOURCE PARTNERS LP

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
The Managing General Partner and Partners of
Rhino Resource Partners LP
Lexington, Kentucky

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of Rhino Resource Partners LP and Subsidiaries ("the Partnership") as of December 31, 2018 and 2017, and the related consolidated statements of operations and comprehensive income, partners' capital and cash flows for each of the years in the two-year period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, effective December 31, 2018, the Partnership adopted Accounting Standards Update 2016-01 – *Financial Instruments-Overall (Subtopic 825-10): Recognition and measurement of Financial Assets and Financial Liabilities*. This new standard changed the method of accounting for available-for-sale equity securities. Such securities are now reported at fair value, with unrealized gains and losses recognized in Mark-to-market adjustment, net, in the consolidated statements of operations and comprehensive income rather than as an element of other comprehensive income. The opening balance cumulative adjustment reclassified the Partnership's unrealized gain from Accumulated Other Comprehensive Income/Loss to Partners' Capital.

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 Public Company Accounting Oversight Board (United States) (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. The Partnership 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 Partnership'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.

CERTIFIED PUBLIC ACCOUNTANTS

We have served as the Partnership's auditor since 2016.

513 State Street
Bristol, Virginia
March 25, 2019

RHINO RESOURCE PARTNERS LP
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(In thousands)

	As of December 31, 2018	As of December 31, 2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6,172	$ 8,796
Restricted cash	-	7,116
Accounts receivable, net of allowance for doubtful accounts ($0.7 million and $-0- as of December 31, 2018 and 2017, respectively).	15,126	20,386
Inventories	6,573	12,860
Advance royalties, current portion	548	495
Investment in available for sale securities	1,872	11,165
Prepaid expenses and other	2,766	2,891
Total current assets	33,057	63,709
PROPERTY, PLANT AND EQUIPMENT:		
At cost, including coal properties, mine development and construction costs	450,888	440,843
Less accumulated depreciation, depletion and amortization	(277,029)	(263,520)
Net property, plant and equipment	173,859	177,323
Advance royalties, net of current portion	8,026	7,901
Deposits - Workers' Compensation and Surety Programs	8,266	-
Restricted cash	-	5,209
Investment in unconsolidated affiliates	-	130
Other non-current assets	25,410	28,508
TOTAL	$ 248,618	$ 282,780
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 14,185	$ 9,329
Accrued expenses and other	10,107	11,186
Accrued preferred distributions	3,210	6,038
Current portion of long-term debt	2,174	5,475
Current portion of asset retirement obligations	465	498
Total current liabilities	30,141	32,526
NON-CURRENT LIABILITIES:		
Long-term debt, net	22,458	28,573
Asset retirement obligations, net of current portion	18,084	18,164
Other non-current liabilities	41,500	48,071
Total non-current liabilities	82,042	94,808
Total liabilities	112,183	127,334
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
PARTNERS' CAPITAL:		
Limited partners	115,505	130,233
General partner	8,792	8,855
Preferred partners	15,000	15,000
Investment in Royal common stock (NOTE 13)	(4,126)	(4,126)
Common unit warrants	1,264	1,264
Accumulated other comprehensive income	-	4,220
Total partners' capital	136,435	155,446
TOTAL	$ 248,618	$ 282,780

See notes to consolidated financial statements.

RHINO RESOURCE PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(In thousands, except per unit data)

	Year Ended December 31,	
	2018	2017
REVENUES:		
Coal sales	$ 244,269	$ 217,192
Other revenues	2,767	1,499
Total revenues	247,036	218,691
COSTS AND EXPENSES:		
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	213,570	178,483
Freight and handling costs	9,084	1,837
Depreciation, depletion and amortization	22,342	21,117
Selling, general and administrative (exclusive of depreciation, depletion and amortization shown separately above)	12,906	11,423
Asset impairment and related charges	-	22,631
Mark-to-market adjustment-unrealized loss	171	-
(Gain) on sale/disposal of assets, net	(3,422)	(68)
Total costs and expenses	254,651	235,423
(LOSS) FROM OPERATIONS	(7,615)	(16,732)
INTEREST AND OTHER (EXPENSE)/INCOME:		
Interest expense and other	(8,483)	(4,010)
Interest income and other	67	86
Equity in net income/(loss) of unconsolidated affiliates	-	36
Total interest and other (expense)	(8,416)	(3,888)
(LOSS) BEFORE INCOME TAXES FROM CONTINUING OPERATIONS	(16,031)	(20,620)
INCOME TAXES	-	-
NET (LOSS) FROM CONTINUING OPERATIONS	(16,031)	(20,620)
DISCONTINUED OPERATIONS (NOTE 4)		
Net Income from discontinued operations	-	1,832
NET (LOSS)	(16,031)	(18,788)
Other comprehensive income:		
Fair value adjustment for investment	-	2,606
COMPREHENSIVE (LOSS)	$ (16,031)	$ (16,182)
General partner's interest in net (loss)/income:		
Net (loss) from continuing operations	$ (81)	$ (112)
Net income from discontinued operations	-	8
General partner's interest in net (loss)	$ (81)	$ (104)
Common unitholders' interest in net (loss)/income:		
Net (loss) from continuing operations	$ (17,617)	$ (24,391)
Net income from discontinued operations	-	1,676
Common unitholders' interest in net (loss)	$ (17,617)	$ (22,715)
Subordinated unitholders' interest in net (loss)/income:		
Net (loss) from continuing operations	$ (1,543)	$ (2,155)
Net income from discontinued operations	-	148
Subordinated unitholders' interest in net (loss)	$ (1,543)	$ (2,007)
Preferred unitholders' interest in net income:		
Net income from continuing operations	$ 3,210	$ 6,038
Net income from discontinued operations	-	-
Preferred unitholders' interest in net income	$ 3,210	$ 6,038
Net (loss)/income per limited partner unit, basic:		
Common units:		
Net (loss) per unit from continuing operations	$ (1.35)	$ (1.88)
Net income per unit from discontinued operations	-	0.13
Net (loss) per common unit, basic	$ (1.35)	$ (1.75)
Subordinated units		
Net (loss) per unit from continuing operations	$ (1.35)	$ (1.88)
Net income per unit from discontinued operations	-	0.13
Net (loss) per subordinated unit, basic	$ (1.35)	$ (1.75)
Preferred units		
Net income per unit from continuing operations	$ 2.14	$ 4.03
Net income per unit from discontinued operations	-	-
Net income per preferred unit, basic	$ 2.14	$ 4.03
Net (loss)/income per limited partner unit, diluted:		
Common units		
Net (loss) per unit from continuing operations	$ (1.35)	$ (1.88)
Net income per unit from discontinued operations	-	0.13

Net (loss) per common unit, diluted	$ (1.35)	$ (1.75)
Subordinated units		
Net (loss) per unit from continuing operations	$ (1.35)	$ (1.88)
Net income per unit from discontinued operations	-	0.13
Net (loss) per subordinated unit, diluted	$ (1.35)	$ (1.75)
Preferred units		
Net income per unit from continuing operations	$ 2.14	$ 4.03
Net income per unit from discontinued operations	-	-
Net income per preferred unit, diluted	$ 2.14	$ 4.03
Weighted average number of limited partner units outstanding, basic:		
Common units	13,062	12,965
Subordinated units	1,144	1,146
Preferred units	1,500	1,500
Weighted average number of limited partner units outstanding, diluted:		
Common units	13,062	12,965
Subordinated units	1,144	1,146
Preferred units	1,500	1,500

See notes to consolidated financial statements.

RHINO RESOURCE PARTNERS LP
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017
(In thousands)

	Limited Partners				General Partner	Preferred Partner	Accumulated Other Comprehensive		Total Partners'
	Common		Subordinated						
	Units	Capital	Units	Capital	Capital	Capital	Income/(Loss)	Other	Capital
BALANCE - December 31, 2016	12,906	$ 73,306	1,236	$79,390	$ 8,959	$ 15,000	$ 1,614	$ -	$178,269
Net (loss)/income	-	(22,715)	-	(2,007)	(104)	6,038	-	-	(18,788)
Preferred distribution earned	-	-	-	-	-	(6,038)	-	-	(6,038)
Issuance of units	88	259	-	-	-	-	-	-	259
Note receivable from Royal for SPA	-	2,000	-	-	-	-	-	-	2,000
Mark-to-market investment in Mammoth	-	-	-	-	-	-	2,606	-	2,606
Issuance of common unit warrants	-	-	-	-	-	-	-	1,264	1,264
Subordinated units surrendered	-	-	(90)	-	-	-	-	-	-
Investment in Royal Common stock	-	-	-	-	-	-	-	(4,126)	(4,126)
BALANCE - December 31, 2017	12,994	$ 52,850	1,146	$77,383	$ 8,855	$ 15,000	$ 4,220	$(2,862)	$155,446
Net (loss)/income		$(17,617)		$ (1,543)	$ (81)	$ 3,210			$ (16,031)
Impact from adoption of ASU 2016-01	-	3,861	-	341	18	-	$ (4,220)	-	-
Preferred partner distribution earned	-	-	-	-	-	(3,210)	-	-	(3,210)
Subordinated units surrendered	-	-	(2)	-	-	-	-	-	-
Issuance of units	104	230	-	-	-	-	-	-	230
BALANCE - December 31, 2018	13,098	$ 39,324	1,144	$76,181	$ 8,792	$ 15,000	$ -	$(2,862)	$136,435

See notes to consolidated financial statements.

RHINO RESOURCE PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,	
	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (loss)	$ (16,031)	$ (18,788)
Adjustments to reconcile net (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	22,342	21,610
Accretion on asset retirement obligations	1,269	1,493
Amortization of advance royalties	667	1,116
Amortization of debt issuance costs	1,818	1,466
Provision for doubtful accounts	737	56
Amortization of debt discount	421	-
Equity in net (income)/loss of unconsolidated affiliates	-	(36)
Loss on retirement of advance royalties	113	136
(Gain) on sale/disposal of assets—net	(3,422)	(68)
Loss on impairment of assets	-	22,631
(Gain)/loss on business disposal	-	(3,238)
Equity-based compensation	230	260
Mark-to-market adjustment-unrealized loss	171	-
Changes in assets and liabilities:		
Accounts receivable	4,618	(6,945)
Inventories	6,288	(4,811)
Advance royalties	(958)	(1,097)
Prepaid expenses and other assets	3,223	(729)
Accounts payable	4,640	(1,491)
Accrued expenses and other liabilities	(6,639)	4,041
Asset retirement obligations	(839)	(1,045)
Net cash provided by operating activities	18,648	14,561
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to property, plant, and equipment	(24,380)	(20,078)
Proceeds from sales of property, plant, and equipment	4,855	656
Proceeds from Elk Horn disposal	-	890
Proceeds from sale of Mammoth shares	11,887	-
Net cash used in investing activities	(7,638)	(18,532)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings on line of credit	-	132,200
Repayments on line of credit	-	(142,240)
Proceeds from issuance of other debt	1,622	-
Proceeds from new debt issuance	-	40,000
Proceeds from short-term borrowing	5,000	-
Repayments on long-term debt	(15,952)	-
Repayments on other debt	(1,099)	-
Deposit for workers' compensation and surety programs	(8,266)	-
Payments of debt issuance costs	(1,225)	(4,915)
Preferred distributions paid	(6,039)	-
Net cash (used in)/provided by financing activities	(25,959)	25,045
NET (DECREASE)/INCREASE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	(14,949)	21,074
CASH, CASH EQUIVALENTS AND RESTRICTED CASH—Beginning of period	21,121	47
CASH, CASH EQUIVALENTS AND RESTRICTED CASH—End of period	$ 6,172	$ 21,121
Summary Statement of Financial Position:		
Cash and cash equivalents	$ 6,172	$ 8,796
Restricted cash - current portion	-	7,116
Restricted cash - noncurrent portion	-	5,209
	$ 6,172	$ 21,121

See notes to consolidated financial statements.

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization—Rhino Resource Partners LP and subsidiaries (the "Partnership") is a Delaware limited partnership formed on April 19, 2010 to acquire Rhino Energy LLC (the "Predecessor" or the "Operating Company"). The Partnership had no operations during the period from April 19, 2010 (date of inception) to October 5, 2010 (the consummation of the initial public offering ("IPO") date of the Partnership). The Operating Company and its wholly owned subsidiaries produce and market coal from surface and underground mines in Kentucky, Ohio, West Virginia and Utah. The majority of the Partnership's sales are made to electric utilities, industrial consumers and other coal-related organizations in the United States.

Through a series of transactions completed in the first quarter of 2016, Royal Energy Resources, Inc. ("Royal") acquired a majority ownership and control of the Partnership and 100% ownership of the Partnership's general partner. The Partnership's common units trade on the OTCQB Marketplace under the ticker symbol "RHNO."

Basis of Presentation and Principles of Consolidation—The accompanying consolidated financial statements include the accounts of Rhino Resource Partners LP and its subsidiaries. Intercompany transactions and balances have been eliminated in consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND GENERAL

Trade Receivables and Concentrations of Credit Risk. See Note 16 for discussion of major customers. The Partnership does not require collateral or other security on accounts receivable. The credit risk is controlled through credit approvals and monitoring procedures.

Cash, Cash Equivalents and Restricted Cash. The Partnership considers all highly liquid investments purchased with original maturities of three months or less to be cash equivalents. The Partnership early adopted ASU No. 2016-18, *Statement of Cash Flows-Restricted Cash* as of December 31, 2017 and as such its consolidated statements of cash flows for all historical periods reflect restricted cash combined with cash and cash equivalents. The Partnership did not have any other material impact from the early adoption of this ASU.

Inventories. Inventories are stated at the lower of cost, based on a three month rolling average, or market. Inventories primarily consist of coal contained in stockpiles.

Advance Royalties. The Partnership is required, under certain royalty lease agreements, to make minimum royalty payments whether or not mining activity is being performed on the leased property. These minimum payments may be recoupable once mining begins on the leased property. The Partnership capitalizes the recoupable minimum royalty payments and amortizes the deferred costs on the units-of-production method once mining activities begin or expenses the deferred costs when the Partnership has ceased mining or has made a decision not to mine on such property.

Property, Plant and Equipment. Property, plant, and equipment, including coal properties, mine development costs and construction costs, are recorded at cost, which includes construction overhead and interest, where applicable. Expenditures for major renewals and betterments are capitalized, while expenditures for maintenance and repairs are expensed as incurred. Mining and other equipment and related facilities are depreciated using the straight-line method based upon the shorter of estimated useful lives of the assets or the estimated life of each mine. Coal properties are depleted using the units-of-production method, based on estimated proven and probable reserves. Mine development costs are amortized using the units-of-production method, based on estimated proven and probable reserves. The Partnership assumes zero salvage values for the majority of its property, plant and equipment when depreciation and amortization are calculated. Gains or losses arising from sales or retirements are included in current operations.

Stripping costs incurred in the production phase of a mine for the removal of overburden or waste materials for the purpose of obtaining access to coal that will be extracted are variable production costs that are included in the cost of inventory produced and extracted during the period the stripping costs are incurred. The Partnership defines a surface mine as a location where the Partnership utilizes operating assets necessary to extract coal, with the geographic boundary determined by property control, permit boundaries, and/or economic threshold limits. Multiple pits that share common infrastructure and processing equipment may be located within a single surface mine boundary, which can cover separate coal seams that typically are recovered incrementally as the overburden depth increases. In accordance with the accounting guidance for extractive mining activities, the Partnership defines a mine in production as one from which saleable minerals have begun to be extracted (produced) from an ore body, regardless of the level of production; however, the production phase does not commence with the removal of de minimis saleable mineral material that occurs in conjunction with the removal of overburden or waste material for the purpose of obtaining access to an ore body. The Partnership capitalizes only the development cost of the first pit at a mine site that may include multiple pits.

Asset Impairments for Coal Properties, Mine Development Costs and Other Coal Mining Equipment and Related Facilities. The Partnership follows the accounting guidance in Accounting Standards Codification ("ASC") 360, Property, Plant and Equipment, on the impairment or disposal of property, plant and equipment for its coal mining assets, which requires that projected future cash flows from use and disposition of assets be compared with the carrying amounts of those assets when potential impairment is indicated. When the sum of projected undiscounted cash flows is less than the carrying amount, impairment losses are recognized. In determining such impairment losses, the Partnership must determine the fair value for the coal mining assets in question in accordance with the applicable fair value accounting guidance. Once the fair value is determined, the appropriate impairment loss must be recorded as the difference between the carrying amount of the coal mining assets and their respective fair values. Also, in certain situations, expected mine lives are shortened because of changes to planned operations or changes in coal reserve estimates. When that occurs and it is determined that the mine's underlying costs are not recoverable in the future, reclamation and mine closing obligations are accelerated and the mine closing accrual is increased accordingly. To the extent it is determined that coal asset carrying values will not be recoverable during a shorter mine life, a provision for such impairment is recognized.

Debt Issuance Costs. Debt issuance costs reflect fees incurred to obtain financing and are amortized (included in interest expense) using the effective interest method over the life of the related debt. Debt issuance costs are presented as a direct deduction from long-term debt for the years ended December 31, 2018 and 2017. The effective interest rate for 2018 was 23.88%.

Asset Retirement Obligations. The accounting guidance for asset retirement obligations addresses asset retirement obligations that result from the acquisition, construction or normal operation of long-lived assets. This guidance requires companies to recognize asset retirement obligations at fair value when the liability is incurred or acquired. Upon initial recognition of a liability, an amount equal to the liability is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The Partnership has recorded the asset retirement costs for its mining operations in Coal properties.

The Partnership estimates its future cost requirements for reclamation of land where it has conducted surface and underground mining operations, based on its interpretation of the technical standards of regulations enacted by the U.S. Office of Surface Mining, as well as state regulations. These costs relate to reclaiming the pit and support acreage at surface mines and sealing portals at underground mines. Other reclamation costs are related to refuse and slurry ponds, as well as holding and related termination/exit costs.

The Partnership expenses contemporaneous reclamation which is performed prior to final mine closure. The establishment of the end of mine reclamation and closure liability is based upon permit requirements and requires significant estimates and assumptions, principally associated with regulatory requirements, costs and recoverable coal reserves. Annually, the Partnership reviews its end of mine reclamation and closure liability and makes necessary adjustments, including mine plan and permit changes and revisions to cost and production levels to optimize mining and reclamation efficiency. When a mine life is shortened due to a change in the mine plan, mine closing obligations are accelerated, the related accrual is increased and the related asset is reviewed for impairment, accordingly.

The adjustments to the liability from annual recosting reflect changes in expected timing, cash flow and the discount rate used in the present value calculation of the liability. Each respective year includes a range of discount rates that are dependent upon the timing of the cash flows of the specific obligations. Changes in the asset retirement obligations for the year ended December 31, 2018 were calculated with discount rates that ranged from 10.6% to 12.1%. Changes in the asset retirement obligations for the year ended December 31, 2017 were calculated with discount rates that ranged from 9.7% to 11.9%. The discount rates changed in each respective year due to changes in applicable market indicators that are used to arrive at an appropriate discount rate. Other recosting adjustments to the liability are made annually based on inflationary cost increases or decreases and changes in the expected operating periods of the mines. The related inflation rate utilized in the recosting adjustments was 2.3 % for 2018 and 2017.

Revenue Recognition. The Partnership adopted ASU 2014-09, Topic 606 on January 1, 2018, using the modified retrospective method. The adoption of Topic 606 had no impact on revenue amounts recorded on the Partnership's financial statements (See Note 17 for additional discussion). Most of the Partnership's revenues are generated under coal sales contracts with electric utilities, coal brokers, domestic and non-U.S. steel producers, industrial companies or other coal-related organizations. Revenue is recognized and recorded when shipment or delivery to the customer has occurred, prices are fixed or determinable, the title or risk of loss has passed in accordance with the terms of the sales agreement and collectability is reasonably assured. Under the typical terms of these agreements, risk of loss transfers to the customers at the mine or port, when the coal is loaded on the rail, barge, truck or other transportation source that delivers coal to its destination. Advance payments received are deferred and recognized in revenue as coal is shipped and title has passed.

Freight and handling costs paid directly to third-party carriers and invoiced separately to coal customers are recorded as freight and handling costs and freight and handling revenues, respectively. Freight and handling costs billed to customers as part of the contractual per ton revenue of customer contracts is included in coal sales revenue.

Other revenues generally consist of coal royalty revenues, coal handling and processing revenues, rebates and rental income. With respect to other revenues recognized in situations unrelated to the shipment of coal, the Partnership carefully reviews the facts and circumstances of each transaction and does not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the seller's price to the buyer is fixed or determinable and collectability is reasonably assured.

Equity-Based Compensation. The Partnership applies the provisions of ASC Topic 718 to account for any unit awards granted to employees or directors. This guidance requires that all share-based payments to employees or directors, including grants of stock options, be recognized in the financial statements based on their fair value. The general partner has granted restricted units to directors and certain employees of the general partner and Partnership. The fair value of each restricted unit was calculated using the closing price of the Partnership's common units on the date of grant.

Derivative Financial Instruments. On occasion, the Partnership has used diesel fuel contracts to manage the risk of fluctuations in the cost of diesel fuel. The Partnership's diesel fuel contracts have met the requirements for the normal purchase normal sale ("NPNS") exception prescribed by the accounting guidance on derivatives and hedging, based on management's intent and ability to take physical delivery of the diesel fuel. The Partnership had one diesel fuel contract as of December 31, 2018 to purchase approximately 1.0 million gallons of diesel fuel at fixed prices through December 31, 2019.

Investments in Joint Ventures. Investments in joint ventures are accounted for using the equity method or cost basis depending upon the level of ownership, the Partnership's ability to exercise significant influence over the operating and financial policies of the investee and whether the Partnership is determined to be the primary beneficiary of a variable interest entity. Equity investments are recorded at original cost and adjusted periodically to recognize the Partnership's proportionate share of the investees' net income or losses after the date of investment. Any losses from the Partnership's equity method investment are absorbed by the Partnership based upon its proportionate ownership percentage. If losses are incurred that exceed the Partnership's investment in the equity method entity, then the Partnership must continue to record its proportionate share of losses in excess of its investment. Investments are written down only when there is clear evidence that a decline in value that is other than temporary has occurred.

Income Taxes. The Partnership is considered a partnership for income tax purposes. Accordingly, the partners report the Partnership's taxable income or loss on their individual tax returns.

Loss Contingencies. In accordance with the guidance on accounting for contingencies, the Partnership records loss contingencies at such time that an unfavorable outcome becomes probable and the amount can be reasonably estimated. When the reasonable estimate is a range, the recorded loss is the best estimate within the range. If no amount in the range is a better estimate than any other amount, the minimum amount of the range is recorded. The Partnership discloses information concerning loss contingencies for which an unfavorable outcome is probable. See Note 14, "Commitments and Contingencies," for a discussion of such matters.

Management's Use of Estimates. The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements as well as the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Recently Issued Accounting Standards. In January 2016, the FASB issued ASU 2016-01, *Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01").* ASU 2016-01 requires entities to measure equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) at fair value and recognize any changes in fair value in net income. An exception is available for equity investments without a readily determinable fair value, but provides a new measurement alternative where entities may choose to measure those investments at cost, less any impairment, plus or minus any changes resulting from observable price changes in transactions for the same issuer. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017. Upon adoption during 2018, the Partnership recorded a $4.2 million reclassification from accumulated other comprehensive income to partners' capital relating to securities with a readily determinable fair value.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*. ASU 2016-02 requires that lessees recognize all leases (other than leases with a term of twelve months or less) on the balance sheet as lease liabilities, based upon the present value of the lease payments, with corresponding right of use assets. The standard is effective for public companies with fiscal years beginning after December 31, 2018. ASU 2016-02 also makes targeted changes to other aspects of current guidance, including identifying a lease and lease classification criteria as well as the lessor accounting model, including guidance on separating components of a contract and consideration in the contract. The Partnership has established an implementation team and has implemented a new lease accounting information system. In July 2018, the FASB issued additional authoritative guidance providing companies with an optional prospective transition method to apply the provisions of this guidance. The Partnership will adopt the standard in the first quarter of 2019 and elect this transition method to apply the standard prospectively. The Partnership's adoption of this standard is expected to result in the recognition of between $13.0 million and $16.0 million of right-of-use assets and lease liabilities on the consolidated statements of financial position.

In January 2017, the FASB issued ASU 2017-01, "Business Combinations (Topic 805)." ASU 2017-01 clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The Partnership has adopted this standard on its unaudited condensed consolidated financial statements, which has no current period impact but may impact future periods in which acquisitions are completed.

In July 2017, the FASB issued ASU 2017-11, "Earnings Per Share (Topic 260): Distinguishing Liabilities from Equity (Topic 480), I. Derivatives and Hedging (Topic 815): Accounting for Certain Financial Instruments with Down Round Features and II. Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests with a Scope Exception." Part I of ASU 2017-11 will result in freestanding equity-linked financial instruments, such as warrants, and conversion options in convertible debt or preferred stock to no longer be accounted for as a derivative liability at fair value as a result of the existence of a down round feature. For freestanding equity-classified financial instruments, the amendments require entities that present earnings per share (EPS) in accordance with Topic 260 to recognize the effect of the down round feature when it is triggered. That effect is treated as a dividend and as a reduction of income available to common shareholders in basic EPS. The amendments in Part II recharacterize the indefinite deferral of certain provisions of Topic 480 that now are presented as pending content in the Codification. The amendments in Part II do not require any transition guidance as the amendments do not have an accounting effect. The amendments in ASU 2017-11 will be effective on January 1, 2020, and the Part I amendments must be applied retrospectively. Early application is permitted. The Partnership early adopted ASU 2017-11, which did not have any material impact.

3. SUBSEQUENT EVENTS

Effective February 13, 2019, the Operating Company, the Partnership, certain of the Operating Company's identified as Borrowers (together with the Operating Company, the "Borrowers"), the Partnership and certain other Operating Company subsidiaries identified as Guarantors (together with the Partnership, the "Guarantors"), entered into a second amendment (the "Amendment") to the Financing Agreement (the "Financing Agreement") originally executed on December 27, 2017 with Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders therein (the "Lenders"). The Amendment provides the Lender's consent for the Partnership to pay a one-time cash distribution on February 14, 2019 to the Series A Preferred Unitholders an amount not to exceed approximately $3.2 million. The Amendment allows the Partnership to sell its remaining shares of Mammoth Energy Services, Inc. and utilize the proceeds for payment of the one-time cash distribution to the Series A Preferred Unitholders and waives the requirement to use such proceeds to prepay the outstanding principal amount outstanding under the Financing Agreement.

The Amendment also waives any Event of Default that has or would otherwise arise under Section 9.01(c) of the Financing Agreement solely by reason of the Borrowers failing to comply with the Fixed Charge Coverage Ratio covenant in Section 7.03(b) of the Financing Agreement for the fiscal quarter ending December 31, 2018. The Amendment includes an amendment fee of approximately $0.6 million payable by the Partnership on May 13, 2019 and an exit fee equal to 1% of the principal amount of the term loans made under the Financing Agreement that is payable on the earliest of (w) the final maturity date of the Financing Agreement, (x) the termination date of the Financing Agreement, (y) the acceleration of the obligations under the Financing Agreement for any reason, including, without limitation, acceleration in accordance with Section 9.01 of the Financing Agreement, including as a result of the commencement of an insolvency proceeding and (z) the date of any refinancing of the term loan under the Financing Agreement. The Amendment amends the definition of the Make-Whole Amount under the Financing Agreement to extend the date of the Make-Whole Amount period to December 31, 2019.

4. DISCONTINUED OPERATIONS

Sands Hill Mining LLC

On November 7, 2017, the Partnership closed an agreement with a third party to transfer 100% of the membership interests and related assets and liabilities in Sands Hill Mining LLC to the third party in exchange for a future override royalty for any mineral sold, excluding coal, from Sands Hill Mining LLC after the closing date. The Partnership recognized a gain of $3.2 million from the sale of Sands Hill Mining LLC since the third party assumed the reclamation obligations associated with this operation. The disposition of Sands Hill Mining LLC resulted in the Partnership exiting its limestone sales business. The previous operating results of Sands Hill Mining LLC have been reclassified and reported on the (Gain)/loss from discontinued operations line on the Partnership's consolidated statements of operations and comprehensive income for the year ended December 31, 2017.

Sands Hill Mining LLC
Major components of net income from discontinued operations for Sands Hill Mining LLC for years ended December 31, 2018 and 2017 are summarized as follows:

	Year ended December 31,	
	2018	2017
Major line items constituting income from discontinued operations for the Sands Hill Mining disposal:		
Coal sales	$ -	$ 1,280
Limestone sales	-	3,483
Other revenue	-	1,503
Total revenues	-	6,266
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	-	6,316
Freight and handling	-	771
Depreciation, depletion and amortization	-	493
Selling, general and administrative (exclusive of depreciation, depletion and amortization shown separately above)	-	92
(Gain) on sale/disposal of assets, net	-	(3,238)
(Gain) on extinguishment of debt	-	-
Interest income	-	-
Interest expense and other	-	-
Total costs, expenses and other	-	4,434
Income from discontinued operations before income taxes for the Sands Hill Mining disposal	-	1,832
Income taxes	-	-
Net income from discontinued operations	$ -	$ 1,832

Cash Flows.

The depreciation, depletion and amortization amounts for Sands Hill Mining LLC for each period presented are listed in the previous table. The Partnership did not fund any material capital expenditures for Sands Hill Mining LLC for any period presented. Sands Hill Mining LLC did not have any material non-cash operating items or non-cash investing items for any period presented.

5. PREPAID EXPENSES AND OTHER CURRENT ASSETS

Prepaid expenses and other current assets as of December 31, 2018 and 2017 consisted of the following:

	December 31,	
	2018	2017
	(in thousands)	
Other prepaid expenses	$ 971	$ 920
Prepaid insurance	1,397	1,445
Prepaid leases	92	92
Supply inventory	306	434
Total	$ 2,766	$ 2,891

The Partnership acquired 568,794 shares of Mammoth Energy Services, Inc. (NASDAQ: TUSK)("Mammoth Inc.") through a series of transactions in years prior to 2018. During 2018, the Partnership sold 464,694 shares for net consideration of approximately $11.9 million. As of December 31, 2018, the Partnership owned 104,100 shares of Mammoth Inc., which are recorded at fair market value as a current asset on the Partnership's consolidated statements of financial position. The Partnership has included its investment in Mammoth Inc. in its Other category for segment reporting purposes.

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment, including coal properties and mine development and construction costs, as of December 31, 2018 and 2017 are summarized by major classification as follows:

	Useful Lives	December 31, 2018	December 31, 2017
		(in thousands)	
Land and land improvements		$ 13,181	$ 14,687
Mining and other equipment and related facilities	2 - 20 Years	307,300	298,293
Mine development costs	1 - 15 Years	63,681	58,566
Coal properties	1 - 15 Years	63,527	64,070
Construction work in process		3,199	5,227
Total		450,888	440,843
Less accumulated depreciation, depletion and amortization		(277,029)	(263,520)
Net		$ 173,859	$ 177,323

Depreciation expense for mining and other equipment and related facilities, depletion expense for coal, amortization expense for mine development costs and amortization expense for asset retirement costs for the years ended December 31, 2018 and 2017 was as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(in thousands)	
Depreciation expense-mining and other equipment and related facilities	$ 16,869	$ 16,151
Depletion expense for coal properties	1,888	1,693
Amortization expense for mine development costs	3,130	2,987
Amortization expense for asset retirement costs	455	286
Total	$ 22,342	$ 21,117

Taylorville Land Sale

On December 30, 2015, the Partnership completed the sale of its land surface rights for the Taylorville property in central Illinois for approximately $7.2 million in net proceeds. The sale agreement allows the Partnership to retain the mining permit and control of the proven and probable coal reserves at the Taylorville property as the Partnership has the option to repurchase the rights to the land within seven years from the date of the sale agreement. In accordance with ASC 606-10-55, since the Partnership has the option to repurchase the rights to the land, the transaction has been accounted for as a financing arrangement rather than a sale. The Taylorville property of $3.8 million is recorded in the consolidated statements of financial position within the net property, plant and equipment caption and the related liability of $4.4 million is recorded in the consolidated statements of financial position within the other noncurrent liability caption.

Asset Impairments-2018

We performed a comprehensive review of our coal mining operations as well as potential future development projects for the year ended December 31, 2018 to ascertain any potential impairment losses. We did not record any impairment losses for coal properties, mine development costs or coal mining equipment and related facilities for the year ended December 31, 2018.

Asset Impairments-2017

The Partnership performed a comprehensive review of its coal mining operations as well as potential future development projects for the year ended December 31, 2017 to ascertain any potential impairment losses. The Partnership engaged an independent third party to perform a fair market value appraisal on certain parcels of land that it owns in Mesa County, Colorado. The parcels appraised for $6.0 million compared to the carrying value of $6.8 million. The Partnership recorded an impairment loss of $0.8 million, which is recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income. No other coal properties, mine development costs or other coal mining equipment and related facilities were impaired as of December 31, 2017.

7. INTANGIBLE AND OTHER NON-CURRENT ASSETS

Other non-current assets as of December 31, 2018 and 2017 consisted of the following:

	December 31,			
	2018		2017	
	(in thousands)			
Deposits and other	$	1,144	$	423
Due (to) Rhino GP		(84)		(61)
Non-current receivable		24,192		27,806
Deferred expenses		158		340
Total	$	25,410	$	28,508

Non-current receivable. As of December 31 2018 and 2017, the non-current receivable balance of $24.2 million and $27.8 respectively, consisted of the amount due from the Partnership's workers' compensation and black lung insurance providers for potential claims that are the primary responsibility of the Partnership, but are covered under the Partnership's insurance policies. See Note 11, "Workers' Compensation and Black Lung" for discussion of the $24.2 million and $27.8 million that is also recorded in the Partnership's other non-current workers' compensation liabilities.

Intangible purchase option. The Partnership and Rhino Resource Holdings LLC ("Rhino Holdings") executed an option agreement in December 2016 where the Partnership received a call option from Rhino Holdings to acquire substantially all of the outstanding common stock of Armstrong Energy. In exchange for Rhino Holdings granting the Partnership the call option, the Partnership issued 5.0 million common units to Rhino Holdings upon the execution of the option agreement. The Partnership valued the call option at $21.8 million based upon the closing price of the Partnership's publicly traded common units on the date the option agreement was executed. The Partnership has determined the value of the common units issued at December 30, 2016 of $21.8 million constituted an amount that would be applied to the potential acquisition of Armstrong Energy. On October 31, 2017, Armstrong Energy filed Chapter 11 petitions in the Eastern District of Missouri's United States Bankruptcy Court. On February 9, 2018, the U.S. Bankruptcy Court confirmed Armstrong Energy's Chapter 11 reorganization plan and as such the Partnership concluded that the call option was fully impaired. As such, the Partnership recorded an impairment charge of $21.8 million related to the call option, which has been recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income for the year ended December 31, 2017.

8. ACCRUED EXPENSES AND OTHER CURRENT LIABILITIES

Accrued expenses and other current liabilities as of December 31, 2018 and 2017 consisted of the following:

	December 31,			
	2018		2017	
	(in thousands)			
Payroll, bonus and vacation expense	$	2,151	$	2,633
Non-income taxes		2,168		2,738
Royalty expenses		1,669		2,410
Accrued interest		35		132
Health claims		868		871
Workers' compensation & pneumoconiosis		1,900		1,750
Other		1,316		652
Total	$	10,107	$	11,186

9. DEBT

Debt as of December 31, 2018 and 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(in thousands)	
Note payable -Financing Agreement	$ 29,048	$ 40,000
Note payable-other debt	522	-
Net unamortized debt issuance costs	(4,095)	(4,688)
Net unamortized original issue discount	(843)	(1,264)
Total	24,632	34,048
Less current portion	(2,174)	(5,475)
Long-term debt	$ 22,458	$ 28,573

Financing Agreement

On December 27, 2017, the Operating Company, the Partnership, certain of the Operating Company's subsidiaries identified as Borrowers (together with the Operating Company, the "Borrowers"), the Partnership and certain other Operating Company subsidiaries identified as Guarantors (together with the Partnership, the "Guarantors"), entered into a Financing Agreement (the "Financing Agreement") with Cortland Capital Market Services LLC, as Collateral Agent and Administrative agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders therein (the "Lenders"), pursuant to which Lenders have agreed to provide Borrowers with a multi-draw term loan in the aggregate principal amount of $80 million, subject to the terms and conditions set forth in the Financing Agreement. The total principal amount is divided into a $40 million commitment, the conditions of which were satisfied at the execution of the Financing Agreement (the "Effective Date Term Loan Commitment") and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement ("Delayed Draw Term Loan Commitment"). Loans made pursuant to the Financing Agreement are secured by substantially all of the Borrowers' and Guarantors' assets. The Financing Agreement terminates on December 27, 2020.

Loans made pursuant to the Financing Agreement will, at the Borrower's option, either be "Reference Rate Loans" or "LIBOR Rate Loans." Reference Rate Loans bear interest at the greatest of (a) 4.25% per annum, (b) the Federal Funds Rate plus 0.50% per annum, (c) the LIBOR Rate (calculated on a one-month basis) plus 1.00% per annum or (d) the Prime Rate (as published in the Wall Street Journal) or if no such rate is published, the interest rate published by the Federal Reserve Board as the "bank prime loan" rate or similar rate quoted therein, in each case, plus an applicable margin of 9.00% per annum (or 12.00% per annum if the Borrowers have elected to capitalize an interest payment pursuant to the PIK Option, as described below). LIBOR Rate Loans bear interest at the greater of (x) the LIBOR for such interest period divided by 100% minus the maximum percentage prescribed by the Federal Reserve for determining the reserve requirements in effect with respect to eurocurrency liabilities for any Lender, if any, and (y) 1.00%, in each case, plus 10.00% per annum (or 13.00% per annum if the Borrowers have elected to capitalize an interest payment pursuant to the PIK Option). Interest payments are due on a monthly basis for Reference Rate Loans and one-, two- or three-month periods, at the Borrower's option, for LIBOR Rate Loans. If there is no event of default occurring or continuing, the Borrowers may elect to defer payment on interest accruing at 6.00% per annum by capitalizing and adding such interest payment to the principal amount of the applicable term loan (the "PIK Option").

Commencing December 31, 2018, the principal for each loan made under the Financing Agreement will be payable on a quarterly basis in an amount equal to $375,000 per quarter, with all remaining unpaid principal and accrued and unpaid interest due on December 27, 2020. In addition, the Borrowers must make certain prepayments over the term of any loans outstanding, including: (i) the payment of 25% of Excess Cash Flow (as that term is defined in the Financing Agreement) of the Partnership and its subsidiaries for each fiscal year, commencing with respect to the year ending December 31, 2019, (ii) subject to certain exceptions, the payment of 100% of the net cash proceeds from the dispositions of certain assets, the incurrence of certain indebtedness or receipts of cash outside of the ordinary course of business, and (iii) the payment of the excess of the outstanding principal amount of term loans outstanding over the amount of the Collateral Coverage Amount (as that term is defined in the Financing Agreement). In addition, the Lenders are entitled to certain fees, including 1.50% per annum of the unused Delayed Draw Term Loan Commitment for as long as such commitment exists, (ii) for the 12-month period following the execution of the Financing Agreement, a make-whole amount equal to the interest and unused Delayed Draw Term Loan Commitment fees that would have been payable but for the occurrence of certain events, including among others, bankruptcy proceedings or the termination of the Financing Agreement by the Borrowers, and (iii) audit and collateral monitoring fees and origination and exit fees.

The Financing Agreement requires the Borrowers and Guarantor to comply with several affirmative covenants at any time loans are outstanding, including, among others: (i) the requirement to deliver monthly, quarterly and annual financial statements, (ii) the requirement to periodically deliver certificates indicating, among other things, (a) compliance with terms of the Financing Agreement and ancillary loan documents, (b) inventory, accounts payable, sales and production numbers, (c) the calculation of the Collateral Coverage Amount (as that term is defined in the Financing Agreement), (d) projections for the Partnership and its subsidiaries and (e) coal reserve amounts; (ii) the requirement to notify the Administrative Agent of certain events, including events of default under the Financing Agreement, dispositions, entry into material contracts, (iii) the requirement to maintain insurance, obtain permits, and comply with environmental and reclamation laws (iv) the requirement to sell up to $5.0 million of shares in Mammoth Energy Securities, Inc. and use the net proceeds therefrom to prepay outstanding term loans and (v) establish and maintain cash management services and establish a cash management account and deliver a control agreement with respect to such account to the Collateral Agent. The Financing Agreement also contains negative covenants that restrict the Borrowers and Guarantors ability to, among other things: (i) incur liens or additional indebtedness or make investments or restricted payments, (ii) liquidate or merge with another entity, or dispose of assets, (iii) change the nature of their respective businesses; (iii) make capital expenditures in excess, or, with respect to maintenance capital expenditures, lower than, specified amounts, (iv) incur restrictions on the payment of dividends, (v) prepay or modify the terms of other indebtedness, (vi) permit the Collateral Coverage Amount to be less than the outstanding principal amount of the loans outstanding under the Financing Agreement or (vii) permit the trailing six month Fixed Charge Coverage Ratio of the Partnership and its subsidiaries to be less than 1.20 to 1.00 commencing with the six-month period ending June 30, 2018.

The Financing Agreement contains customary events of default, following which the Collateral Agent may, at the request of lenders, terminate or reduce all commitments and accelerate the maturity of all outstanding loans to become due and payable immediately together with accrued and unpaid interest thereon and exercise any such other rights as specified under the Financing Agreement and ancillary loan documents. The Partnership entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. (See Note 13 for further discussion)

On April 17, 2018, the Partnership amended the Financing Agreement to allow for certain activities including a sale leaseback of certain pieces of equipment, the extension of the due date for lease consents required under the Financing Agreement to June 30, 2018 and the distribution to holders of the Series A preferred units of $6.0 million (accrued in the consolidated financial statements at December 31, 2017). Additionally, the amendments provided that the Partnership could sell additional shares of Mammoth Energy Services Inc. stock and retain 50% of the proceeds with the other 50% used to reduce debt. The Partnership reduced its outstanding debt by $3.4 million with proceeds from the sale of Mammoth Energy Services Inc. stock in the second quarter of 2018.

On July 27, 2018, the Partnership entered into a consent with its Lenders related to the Financing Agreement. The consent included the lenders agreement to make a $5 million loan from the Delayed Draw Term Loan Commitment, which was repaid in full on October 26, 2018 pursuant to the terms of the consent. The consent also included a waiver of the requirements relating to the use of proceeds of any sale of the shares of Mammoth Inc. set forth in the consent to the Financing Agreement, dated as of April 17, 2018 and also waived any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended June 30, 2018.

On November 8, 2018, the Partnership entered into a consent with its Lenders related to the Financing Agreement. The consent includes the lenders agreement to waive any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended September 30, 2018.

On December 20, 2018, the Partnership, entered into a limited waiver and consent (the “Waiver”) to the Financing Agreement. The Waiver relates to the sales by the Partnership of certain real property in Western Colorado, the net proceeds of which are required to be used to reduce the Partnership’s debt under the Financing Agreement. As of the date of the Waiver, the Partnership had sold 9 individual lots in smaller transactions. On December 31, 2018, the Partnership used the sale proceeds of approximately $379,000 to reduce the debt. Rather than transmitting net proceeds with respect to each individual transaction, the Partnership and Lenders agreed in principle to delay repayment until an aggregate payment could be made at the end of 2018. The Waiver (i) contains a ratification by the Lenders of the sale of the individual lots to date and waives the associated technical defaults under the Financing Agreement for not making immediate payments of net proceeds therefrom, (ii) permits the sale of certain specified additional lots and (iii) subject to Lender consent, permits the sale of other lots on a going forward basis. The net proceeds of future sales will be held by the Partnership until a later date to be determined by the Lenders.

On February 13, 2019, the Partnership entered into a second amendment to the Financing Agreement. Please refer to Note 3 (Subsequent Events) of the consolidated financial statements included elsewhere in this annual report for more details.

At December 31, 2018, $29.0 million was outstanding under the Financing Agreement at a variable interest rate of Libor plus 10.00% (12.53% at December 31, 2018).

Common Unit Warrants

The Partnership entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. The warrant agreement included the issuance of a total of 683,888 warrants for common units (“Common Unit Warrants”) of the Partnership at an exercise price of $1.95 per unit, which was the closing price of the Partnership’s units on the OTC market as of December 27, 2017. The Common Unit Warrants have a five year expiration date. The Common Unit Warrants and the Rhino common units after exercise are both transferable, subject to applicable US securities laws. The Common Unit Warrant exercise price is $1.95 per unit, but the price per unit will be reduced by future common unit distributions and other further adjustments in price included in the warrant agreement for transactions that are dilutive to the amount of Rhino’s common units outstanding. The warrant agreement includes a provision for a cashless exercise whereby the warrant holders can receive a net number of common units. Per the warrant agreement, the warrants are detached from the Financing Agreement and fully transferable. The Partnership analyzed the Common Unit Warrants in accordance with the applicable accounting literature and concluded the Common Unit Warrants should be classified as equity. The Partnership allocated the $40.0 million proceeds from the Financing Agreement between the Common Unit Warrants and the Financing Agreement based upon their relative fair values. The allocation based upon relative fair values resulted in approximately $1.3 million being recorded for the Common Unit Warrants in the Partner’s Capital equity section and a corresponding reduction in Long-term debt, net on the Partnership’s consolidated statements of financial position.

Letter of Credit Facility – PNC Bank

On December 27, 2017, the Partnership entered into a master letter of credit facility, security agreement and reimbursement agreement (the “LoC Facility Agreement”) with PNC Bank, National Association (“PNC”), pursuant to which PNC agreed to provide the Partnership with a facility for the issuance of standby letters of credit used in the ordinary course of its business (the “LoC Facility”). The LoC Facility Agreement provided that the Partnership pay a quarterly fee at a rate equal to 5% per annum calculated based on the daily average of letters of credit outstanding under the LoC Facility, as well as administrative costs incurred by PNC and a $100,000 closing fee. The LoC Facility Agreement provided that the Partnership reimburse PNC for any drawing under a letter of credit by a specified beneficiary as soon as possible after payment was made. The Partnership’s obligations under the LoC Facility Agreement were secured by a first lien security interest on a cash collateral account that was required to contain no less than 105% of the face value of the outstanding letters of credit. In the event the amount in such cash collateral account was insufficient to satisfy the Partnership’s reimbursement obligations, the amount outstanding would bear interest at a rate per annum equal to the Base Rate (as that term was defined in the LoC Facility Agreement) plus 2.0%. The Partnership was to indemnify PNC for any losses which PNC may have incurred as a result of the issuance of a letter of credit or PNC’s failure to honor any drawing under a letter of credit, subject in each case to certain exceptions. The Partnership provided cash collateral to its counterparties during the third quarter of 2018 and as of September 30, 2018, the LoC Facility was terminated. The Partnership had no outstanding letters of credit at December 31, 2018.

The Partnership did not capitalize any interest costs during the year ended December 31, 2018 or 2017.

Principal payments on debt (excluding unamortized debt issuance costs and unamortized warrant costs) due subsequent to December 31, 2018 are as follows:

	(in thousands)
2019	$ 2,174
2020	27,396
2021	-
2022	-
Thereafter	-
Total principal payments	$ 29,570

10. ASSET RETIREMENT OBLIGATIONS

The changes in asset retirement obligations for the years ended December 31, 2018 and 2017 are as follows:

	Year Ended December 31,	
	2018	2017
	(in thousands)	
Balance at beginning of period (including current portion)	$ 18,662	$ 19,108
Accretion expense	1,269	1,493
Adjustment resulting from disposal of property (1)	-	(223)
Adjustments to the liability from annual recosting and other	(1,083)	(1,656)
Liabilities settled	(299)	(60)
Balance at end of period	18,549	18,662
Less current portion of asset retirement obligation	(465)	(498)
Long-term portion of asset retirement obligation	$ 18,084	$ 18,164

(1) The ($0.2) million adjustment for the year ended December 31, 2017, relates to the sale of the Partnership's Sands Hill Mining entity as discussed in Note 4.

11. WORKERS' COMPENSATION AND BLACK LUNG

Certain of the Partnership's subsidiaries are liable under federal and state laws to pay workers' compensation and coal workers' black lung benefits to eligible employees, former employees and their dependents. The Partnership currently utilizes an insurance program and state workers' compensation fund participation to secure its on-going obligations depending on the location of the operation. Premium expense for workers' compensation benefits is recognized in the period in which the related insurance coverage is provided.

The Partnership's black lung benefit liability is calculated using the service cost method that considers the calculation of the actuarial present value of the estimated black lung obligation. The Partnership's actuarial calculations using the service cost method for its black lung benefit liability are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates. The Partnership's liability for traumatic workers' compensation injury claims is the estimated present value of current workers' compensation benefits, based on actuarial estimates. The Partnership's actuarial estimates for its workers' compensation liability are based on numerous assumptions including claim development patterns, mortality, medical costs and interest rates. The discount rate used to calculate the estimated present value of future obligations for black lung was 4.0% and 3.5%, for December 31, 2018 and 2017, respectively and for workers' compensation the discount rate was 3.4% and 3.0% at December 31, 2018 and 2017, respectively.

The uninsured black lung and workers' compensation expenses for the years ended December 31, 2018 and 2017 are as follows:

	Year Ended December 31, 2018	2017
	(in thousands)	
Black lung benefits:		
Service cost	$ (296)	$ 1,771
Interest cost	391	344
Actuarial loss/(gain)	(893)	924
Total black lung	(798)	3,039
Workers' compensation expense	3,912	3,231
Total expense	$ 3,114	$ 6,270

The changes in the black lung benefit liability for the years ended December 31, 2018 and 2017 are as follows:

	Year Ended December 31, 2018	2017
	(in thousands)	
Benefit obligations at beginning of year	$ 11,446	$ 8,782
Service cost	(296)	1,771
Interest cost	391	344
Actuarial loss/(gain)	(893)	924
Benefits and expenses paid	(554)	(375)
Benefit obligations at end of year	$ 10,094	$ 11,446

The classification of the amounts recognized for the Partnership's workers' compensation and black lung benefits liability as of December 31, 2018 and 2017 are as follows:

	December 31, 2018	2017
	(in thousands)	
Uninsured black lung claims	$ 10,094	$ 11,446
Insured black lung and workers' compensation claims	24,191	27,806
Workers' compensation claims	4,706	5,216
Total obligations	$ 38,991	$ 44,468
Less current portion	(1,900)	(1,750)
Non-current obligations	$ 37,091	$ 42,718

The balance for insured black lung and workers' compensation claims as of December 31, 2018 and 2017 consisted of $24.2 million and $27.8 million, respectively. This is a primary obligation of the Partnership, but is also due from the Partnership's insurance providers and is included in Note 7 as non-current receivables. The Partnership presents this amount on a gross asset and liability basis since a right of setoff does not exist per the accounting guidance in ASC Topic 210. This presentation has no impact on the Partnership's results of operations or cash flows.

12. EMPLOYEE BENEFITS

401(k) Plans—The Partnership and certain subsidiaries sponsor defined contribution savings plans for all employees. Under one defined contribution savings plan, the Partnership matches voluntary contributions of participants up to a maximum contribution based upon a percentage of a participant's salary with an additional matching contribution possible at the Partnership's discretion. The expense under these plans for the years ended December 31, 2018 and 2017 was as follows:

	Year Ended December 31,	
	2018	2017
	(in thousands)	
401(k) plan expense	$ 1,742	$ 1,453

13. PARTNERS' CAPITAL/EQUITY-BASED COMPENSATION

Partners' Capital

Common Unit Warrants —In December 2017, the Partnership entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. The warrant agreement included the issuance of a total of 683,888 warrants for common units ("Common Unit Warrants") of the Partnership at an exercise price of $1.95 per unit, which was the closing price of the Partnership's common units on the OTC market as of December 27, 2017. The Common Unit Warrants have a five year expiration date. The Common Unit Warrants and the Partnership's common units after exercise are both transferable, subject to applicable US securities laws. The Common Unit Warrant exercise price is $1.95 per unit, but the price per unit will be reduced by future common unit distributions and other further adjustments in price included in the warrant agreement for transactions that are dilutive to the amount of the Partnership's common units outstanding. The warrant agreement includes a provision for a cashless exercise where the warrant holders can receive a net number of common units. Per the warrant agreement, the warrants are detached from the Financing Agreement and fully transferable. The Partnership analyzed the Common Unit Warrants in accordance with the applicable accounting literature and concluded the Common Unit Warrants should be classified as equity. The Partnership allocated the $40.0 million proceeds from the Financing Agreement between the Common Unit Warrants and the Financing Agreement based upon their relative fair values. The allocation based upon relative fair values resulted in approximately $1.3 million being recorded for the Common Unit Warrants in the Partner's Capital equity section and a corresponding reduction in Long-term debt, net on the Partnership's consolidated statements of financial position.

Series A Preferred Units— On December 30, 2016, the general partner entered into the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership ("Amended and Restated Partnership Agreement") to create, authorize and issue the Series A preferred units.

The Series A preferred units rank senior to all classes or series of equity securities of the Partnership with respect to distribution rights and rights upon liquidation. The holders of the Series A preferred units are entitled to receive annual distributions equal to the greater of (i) 50% of the CAM Mining free cash flow (as defined below) and (ii) an amount equal to the number of outstanding Series A preferred units multiplied by $0.80. "CAM Mining free cash flow" is defined in the Amended and Restated Partnership Agreement as (i) the total revenue of the Partnership's Central Appalachia business segment, minus (ii) the cost of operations (exclusive of depreciation, depletion and amortization) for the Partnership's Central Appalachia business segment, minus (iii) an amount equal to $6.50, multiplied by the aggregate number of coal tons sold by the Partnership from its Central Appalachia business segment. If the Partnership fails to pay any or all of the distributions in respect of the Series A preferred units, such deficiency will accrue until paid in full and the Partnership will not be permitted to pay any distributions on its Partnership interests that rank junior to the Series A preferred units, including its common units. The Series A preferred units will be liquidated in accordance with their capital accounts and upon liquidation will be entitled to distributions of property and cash in accordance with the balances of their capital accounts prior to such distributions on equity securities that rank junior to the Series A preferred units.

The Series A preferred units vote on an as-converted basis with the common units, and the Partnership is restricted from taking certain actions without the consent of the holders of a majority of the Series A preferred units, including: (i) the issuance of additional Series A preferred units, or securities that rank senior or equal to the Series A preferred units; (ii) the sale or transfer of CAM Mining or a material portion of its assets; (iii) the repurchase of common units, or the issuance of rights or warrants to holders of common units entitling them to purchase common units at less than fair market value; (iv) consummation of a spin off; (v) the incurrence, assumption or guaranty of indebtedness for borrowed money in excess of $50.0 million except indebtedness relating to entities or assets that are acquired by the Partnership or its affiliates that is in existence at the time of such acquisition or (vi) the modification of CAM Mining's accounting principles or the financial or operational reporting principles of the Partnership's Central Appalachia business segment, subject to certain exceptions.

The Partnership has the option to convert the outstanding Series A preferred units at any time on or after the time at which the amount of aggregate distributions paid in respect of each Series A preferred unit exceeds $10.00 per unit. Each Series A preferred unit will convert into a number of common units equal to the quotient (the "Series A Conversion Ratio") of (i) the sum of $10.00 and any unpaid distributions in respect of such Series A Preferred Unit divided by (ii) 75% of the volume-weighted average closing price of the common units for the preceding 90 trading days (the "VWAP"); provided however, that the VWAP will be capped at a minimum of $2.00 and a maximum of $10.00. On December 31, 2021, all outstanding Series A preferred units will convert into common units at the then applicable Series A Conversion Ratio.

During the first quarter of 2018, the Partnership paid $6.0 million in distributions earned for the year ended December 31, 2017 to holders of the Series A preferred units. The Partnership has accrued $3.2 million for distributions to holders of the Series A preferred units for the year ended December 31, 2018.

Investment in Royal Common Stock— On September 1, 2017, Royal elected to convert certain obligations to the Partnership totaling $4.1 million to shares of Royal common stock. Royal issued 914,797 shares of its common stock to the Partnership at a conversion price of $4.51 per share. The price per share was equal to the outstanding balance multiplied by seventy-five percent (75%) of the volume-weighted average closing price of Royal's common stock for the 90 days preceding the date of conversion ("Royal VWAP"), subject to a minimum Royal VWAP of $3.50 and a maximum Royal VWAP of $7.50. The Partnership recorded the $4.1 million conversion as Investment in Royal common stock in the Partners' Capital section of the Partnership's consolidated statements of financial position since Royal does not have significant economic activity apart from its investment in the Partnership.

Other Comprehensive Income— In accordance with Accounting Standards Codification ("ASU") 2016-01, which was effective for fiscal years that began after December 15, 2017, the Partnership ceased recording fair market adjustments for the shares it owns in Mammoth Energy Services, Inc. (NASDAQ: TUSK) ("Mammoth Inc.") in Other Comprehensive Income during 2018. As of December 31, 2017, the Partnership had recorded fair market value adjustments of $4.2 million for its investment in Mammoth Inc. which were recorded in Other Comprehensive Income. As of December 31, 2018 and 2017, the Partnership recorded its investment in Mammoth Inc. as a current asset, which was classified as available-for-sale. Please read Note 2 for additional discussion of the adoption of ASU 2016-01.

Accumulated Distribution Arrearages— Pursuant to the Partnership's partnership agreement, the Partnership's common units accrue arrearages every quarter when the distribution level is below the minimum level of $4.45 per unit. Beginning with the quarter ended June 30, 2015 and continuing through the quarter ended December 31, 2018, the Partnership has suspended the cash distribution on its common units. For each of the quarters ended September 30, 2014, December 31, 2014 and March 31, 2015, the Partnership announced cash distributions per common unit at levels lower than the minimum quarterly distribution. The Partnership has not paid any distribution on its subordinated units for any quarter after the quarter ended March 31, 2012. As of December 31, 2018, the Partnership had accumulated arrearages of $673.1 million.

Equity-Based Compensation

In October 2010, the general partner established the Rhino Long-Term Incentive Plan (the "Plan" or "LTIP"). The Plan is intended to promote the interests of the Partnership by providing to employees, consultants and directors of the general partner, the Partnership or affiliates of either, incentive compensation awards to encourage superior performance. The LTIP provides for grants of restricted units, unit options, unit appreciation rights, phantom units, unit awards, and other unit-based awards.

As of December 31, 2018, the general partner had granted restricted units and unit awards to its directors.

As all grants in 2018 and 2017 vested immediately, the Partnership did not have any unrecognized compensation expense of any non-vested LTIP awards as of December 31, 2018.

14. COMMITMENTS AND CONTINGENCIES

Coal Sales Contracts and Contingencies—As of December 31, 2018, the Partnership had commitments under sales contracts to deliver annually scheduled base quantities of coal as follows:

Year	Tons (in thousands)	Number of customers
2019	3,699	18
2020	1,979	6
2021	352	2

Some of the contracts have sales price adjustment provisions, subject to certain limitations and adjustments, based on a variety of factors and indices.

Purchase Commitments—As of December 31, 2018, the Partnership had a commitment to purchase approximately 1.0 million gallons of diesel fuel at a fixed price from January 2019 through December 2019 for approximately $2.2 million.

Purchased Coal Expenses—The Partnership incurs purchased coal expense from time to time related to coal purchase contracts. In addition, the Partnership incurs expense from time to time related to coal purchased on the over-the-counter market ("OTC"). Purchase coal expense from coal purchase contracts and expense from OTC purchases for the years ended December 31, 2018 and 2017 was as follows:

	Year Ended December 31,	
	2018	2017
	(in thousands)	
Purchased coal expense	$ 31	$ 377
OTC expense	$ -	$ -

Leases—The Partnership leases various mining, transportation, other equipment and facilities under operating leases. The Partnership also leases coal reserves under agreements that call for royalties to be paid as the coal is mined. Lease and royalty expense for the years ended December 31, 2018 and 2017 was as follows:

	Year Ended December 31,	
	2018	2017
	(in thousands)	
Lease expense	$ 3,917	$ 3,752
Royalty expense	$ 13,607	$ 14,274

Approximate future minimum lease and royalty payments (not including advance royalties already paid and recorded as assets in the accompanying statements of financial position) are as follows:

Years Ending December 31,	Royalties	Leases
	(in thousands)	
2019	$ 1,580	$ 3,924
2020	1,568	3,867
2021	1,568	3,044
2022	1,568	1,702
2023	1,568	700
Thereafter	7,842	1,730
Total minimum royalty and lease payments	$ 15,694	$ 14,967

Environmental Matters—Based upon current knowledge, the Partnership believes that it is in compliance with environmental laws and regulations as currently promulgated. However, the exact nature of environmental control problems, if any, which the Partnership may encounter in the future cannot be predicted, primarily because of the increasing number, complexity and changing character of environmental requirements that may be enacted by federal and state authorities.

Legal Matters—The Partnership is involved in various legal proceedings arising in the ordinary course of business due to claims from various third parties, as well as potential citations and fines from the Mine Safety and Health Administration, potential claims from land or lease owners and potential property damage claims from third parties. The Partnership is not party to any other pending litigation that is probable to have a material adverse effect on the financial condition, results of operations or cash flows of the Partnership. Management of the Partnership is also not aware of any significant legal, regulatory or governmental proceedings against or contemplated to be brought against the Partnership.

Guarantees/Indemnifications and Financial Instruments with Off-Balance Sheet Risk— In the normal course of business, the Partnership is a party to certain guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. No liabilities related to these arrangements are reflected in the consolidated statements of financial position. The Partnership had no outstanding letters of credit at December 31, 2018. The Partnership had outstanding surety bonds with third parties of $42.6 million as of December 31, 2018 to secure reclamation and other performance commitments, which are secured by $3.0 million in cash collateral on deposit with the Partnership's surety bond provider. Of the $42.6 million, approximately $0.4 million relates to surety bonds for Deane Mining, LLC and approximately $3.4 million relates to surety bonds for Sands Hill Mining, LLC, which in each case have not been transferred or replaced by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC as was agreed to by the parties as part of the transactions. The Partnership can provide no assurances that a surety company will underwrite the surety bonds of the purchasers of these entities, nor is the Partnership aware of the actual amount of reclamation at any given time. Further, if there was a claim under these surety bonds prior to the transfer or replacement of such bonds by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC, then the Partnership may be responsible to the surety company for any amounts it pays in respect of such claim. While the buyers are required to indemnify the Partnership for damages, including reclamation liabilities, pursuant the agreements governing the sales of these entities, the Partnership may not be successful in obtaining any indemnity or any amounts received may be inadequate.

The Financing Agreement is fully and unconditionally, jointly and severally guaranteed by the Partnership and substantially all of its wholly owned subsidiaries. Borrowings under the financing agreement are collateralized by the unsecured assets of the Partnership and substantially all of its wholly owned subsidiaries. See Note 9, for a more complete discussion of the Partnership's debt obligations.

15. EARNINGS PER UNIT ("EPU")

The following table presents a reconciliation of the numerators and denominators of the basic and diluted EPU calculations for the years ended December 31, 2018 and 2017:

Year ended December 31, 2018	General Partner	Common Unitholders	Subordinated Unitholders	Preferred Unitholders
	(in thousands, except per unit data)			
Numerator:				
Interest in net (loss)/ income:				
Net (loss)/income from continuing operations	$ (81)	$ (17,617)	$ (1,543)	$ 3,210
Net income from discontinued operations	-	-	-	-
Interest in net (loss)/income	$ (81)	$ (17,617)	$ (1,543)	$ 3,210
Denominator:				
Weighted average units used to compute basic EPU	n/a	13,062	1,144	1,500
Weighted average units used to compute diluted EPU	n/a	13,062	1,144	1,500
Net (loss)/income per limited partner unit, basic:				
Net (loss)/income per unit from continuing operations	n/a	$ (1.35)	$ (1.35)	$ 2.14
Net income per unit from discontinued operations	n/a	-	-	-
Net (loss)/income per limited partner unit, basic	n/a	$ (1.35)	$ (1.35)	$ 2.14
Net (loss)/income per limited partner unit, diluted:				
Net (loss)/income per unit from continuing operations	n/a	$ (1.35)	$ (1.35)	$ 2.14
Net income per unit from discontinued operations	n/a	-	-	-
Net (loss)/income per limited partner unit, diluted	n/a	$ (1.35)	$ (1.35)	$ 2.14

Year ended December 31, 2017	General Partner	Common Unitholders	Subordinated Unitholders	Preferred Unitholders
	(in thousands, except per unit data)			
Numerator:				
Interest in net (loss)/income:				
Net (loss)/income from continuing operations	$ (112)	$ (24,391)	$ (2,155)	$ 6,038
Net income from discontinued operations	8	1,676	148	n/a
Interest in net (loss)/income	$ (104)	$ (22,715)	$ (2,007)	$ 6,038
Denominator:				
Weighted average units used to compute basic EPU	n/a	12,965	1,146	$ 1,500
Weighted average units used to compute diluted EPU	n/a	12,965	1,146	$ 1,500
Net (loss)/income per limited partner unit, basic:				
Net (loss)/income per unit from continuing operations	n/a	$ (1.88)	$ (1.88)	$ 4.03
Net income per unit from discontinued operations	n/a	0.13	0.13	n/a
Net(loss)/income per limited partner unit, basic	n/a	$ (1.75)	$ (1.75)	$ 4.03
Net (loss)/income per limited partner unit, diluted:				
Net (loss)/income per unit from continuing operations	n/a	$ (1.88)	$ (1.88)	$ 4.03
Net income per unit from discontinued operations	n/a	0.13	0.13	n/a
Net (loss)/income per limited partner unit, diluted	n/a	$ (1.75)	$ (1.75)	$ 4.03

Diluted EPU gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive potential units calculated under the treasury stock method if their effect is anti-dilutive. Since the Partnership incurred a total net loss for the years ended December 31, 2018 and 2017, all potential dilutive units were excluded from the diluted EPU calculation for this period because when an entity incurs a net loss in a period, potential dilutive units shall not be included in the computation of diluted EPU since their effect will always be anti-dilutive. There were 683,888 potential dilutive common units related to the Common Unit Warrants as discussed in Note 9 for the year ended December 31, 2018.

16. MAJOR CUSTOMERS

The Partnership had revenues or receivables from the following major customers that in each period equaled or exceeded 10% of revenues or receivables (Note: customers with "n/a" had revenue or receivables below the 10% threshold in any period where this is indicated):

	December 31, 2018 Receivable Balance	Year Ended December 31, 2018 Sales	December 31, 2017 Receivable Balance	Year Ended December 31, 2017 Sales
		(in thousands)		
Javelin Global	$ 4,347	$ 52,777	$ 2,470	$ 15,090
Integrity Coal	937	24,089	2,238	24,234
LGE/KU	467	13,480	1,483	40,217
Dominion Energy	n/a	19,045	1,232	22,087
Big Rivers	863	20,342	n/a	21,716
PacifiCorp Energy	960	12,343	1,717	16,518

17. REVENUE

The Partnership adopted ASC Topic 606 on January 1, 2018, using the modified retrospective method. The adoption of Topic 606 has no impact on revenue amounts recorded on the Partnership's financial statements. The new disclosures required by ASC Topic 606, as applicable, are presented below. The majority of the Partnership's revenues are generated under coal sales contracts. Coal sales accounted for approximately 99.0% of the Partnership's total revenues for the years ended December 31, 2018 and 2017. Other revenues generally consist of coal royalty revenues, coal handling and processing revenues, rebates and rental income, which accounted for approximately 1.0% of the Partnership's total revenues for the years ended December 31, 2018 and 2017.

The majority of the Partnership's coal sales contracts have a single performance obligation (shipment or delivery of coal according to terms of the sales agreement) and as such, the Partnership is not required to allocate the contract's transaction price to multiple performance obligations. All of the Partnership's coal sales revenue is recognized when shipment or delivery to the customer has occurred, prices are fixed or determinable and the title or risk of loss has passed in accordance with the terms of the coal sales agreement. With respect to other revenues recognized in situations unrelated to the shipment of coal, the Partnership carefully reviews the facts and circumstances of each transaction and does not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the seller's price to the buyer is fixed or determinable and collectability is reasonably assured.

In the tables below, the Partnership has disaggregated its revenue by category for each reportable segment as required by ASC Topic 606.

The following table disaggregates revenue by type for each reportable segment for the year ended December 31, 2018:

	Central Appalachia	Northern Appalachia	Rhino Western	Illinois Basin	Other	Total Consolidated
			(in thousands)			
Coal sales						
Steam coal	$ 52,380	$ 18,237	$ 36,186	$ 50,451	$ -	$ 157,254
Met coal	87,015	-	-	-	-	87,015
Other revenue	374	2,205	9	-	179	2,767
Total	$ 139,769	$ 20,442	$ 36,195	$ 50,451	$ 179	$ 247,036

The following table disaggregates revenue by type for each reportable segment for the year ended December 31, 2017:

	Central Appalachia	Northern Appalachia	Rhino Western	Illinois Basin	Other	Total Consolidated
	(in thousands)					
Coal sales						
Steam coal	$ 37,805	$ 15,856	$ 35,447	$ 64,051	$ -	$ 153,159
Met coal	64,033	-	-	-	-	64,033
Other revenue	154	1,289	11	4	41	1,499
Total	$ 101,992	$ 17,145	$ 35,458	$ 64,055	$ 41	$ 218,691

18. FAIR VALUE MEASUREMENTS

The Partnership determines the fair value of assets and liabilities based on the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants. The fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. The fair value hierarchy is based on whether the inputs to valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Partnership's assumptions of what market participants would use.

The fair value hierarchy includes three levels of inputs that may be used to measure fair value as described below:

Level One - Quoted prices for identical instruments in active markets.

Level Two - The fair value of the assets and liabilities included in Level 2 are based on standard industry income approach models that use significant observable inputs.

Level Three - Unobservable inputs significant to the fair value measurement supported by little or no market activity.

In those cases when the inputs used to measure fair value meet the definition of more than one level of the fair value hierarchy, the lowest level input that is significant to the fair value measurement in its totality determines the applicable level in the fair value hierarchy.

The book values of cash and cash equivalents, accounts receivable and accounts payable are considered to be representative of their respective fair values because of the immediate short-term maturity of these financial instruments. The fair value of the Partnership's financing agreement was determined based upon a market approach and approximates the carrying value at December 31, 2018. The fair value of the Partnership's financing agreement is a Level 2 measurement.

As of December 31, 2018 and December 31, 2017, the Partnership had a recurring fair value measurement relating to its investment in Mammoth Inc. The Partnership owned 104,100 shares of Mammoth Inc. as of December 31, 2018. The Partnership's shares of Mammoth Inc. are classified as an investment on the Partnership's consolidated statements of financial position. Based on the availability of a quoted price, the recurring fair value measurement of the Mammoth Inc. shares is a Level 1 measurement.

For the year ended December 31, 2017, the Partnership had a nonrecurring fair value measurement related to an asset impairment. The Partnership engaged an independent third party to perform a fair market value appraisal on certain parcels of land that it owns in Mesa County, Colorado. The parcels appraised for $6.0 million compared to the carrying value of $6.8 million. The Partnership recorded an impairment loss of $0.8 million, which is recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income. Based on the availability of an independent fair market value appraisal, the nonrecurring fair value measurement of the impairment is a Level 2 measurement.

For the year ended December 31, 2017, the Partnership had a nonrecurring fair value measurement related to the Common Unit Warrants (see Note 9 for discussion of the Common Unit Warrants). The Partnership calculated the fair value of the Common Unit Warrants using a Black-Scholes model with inputs that include the Common Unit Warrants' strike price, the term of the agreement, historical volatility of the Partnership's common units and the risk free interest rate. The nonrecurring fair value measurement for the Common Unit Warrants for the year ended December 31, 2018 was a Level 3 measurement.

19. RELATED PARTY AND AFFILIATE TRANSACTIONS

Related Party	Description	2018	2017
		(in thousands)	
Royal Energy Resources, Inc.	Note receivable conversion	-	4,100
Royal Energy Resources, Inc.	Commissions and other fees	588	819
Weston Energy LLC	Preferred distribution	3,210	6,038
Mammoth Energy Services, Inc.	Proceeds from sale of shares	11,887	-
Mammoth Energy Partners LP	Investment in unconsolidated affiliate	-	40
Sturgeon Acquisitions LLC	Equity in net income of unconsolidated affiliate	-	(4)

20. SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

Cash payments for interest were $6.0 million and $2.5 million for the years ended December 31, 2018 and 2017, respectively.

The consolidated statement of cash flows for the year ended December 31, 2018 is exclusive of approximately $1.2 million of property, plant and equipment additions which are recorded in Accounts payable.

The consolidated statement of cash flows for the year ended December 31, 2017 is exclusive of approximately $1.0 million of property, plant and equipment additions which are recorded in Accounts payable.

The consolidated statement of cash flows for the year ended December 31, 2017 is exclusive of $4.1 million related to the conversion of the Rhino Promissory Note and the Weston Promissory Note to shares of Royal common stock. See Note 13, "Partners' Capital/Equity Based Compensation" for further discussion.

21. SEGMENT INFORMATION

The Partnership primarily produces and markets coal from surface and underground mines in Kentucky, West Virginia, Ohio and Utah. The Partnership sells primarily to electric utilities in the United States.

As of December 31, 2018, the Partnership has four reportable business segments: Central Appalachia, Northern Appalachia, Rhino Western and Illinois Basin. Additionally, the Partnership has an Other category that includes its ancillary businesses.

The Partnership's Other category as reclassified is comprised of the Partnership's ancillary businesses and its remaining oil and natural gas activities. Held for sale assets are included in the applicable segment for reporting purposes. The Partnership has not provided disclosure of total expenditures by segment for long-lived assets, as the Partnership does not maintain discrete financial information concerning segment expenditures for long lived assets, and accordingly such information is not provided to the Partnership's chief operating decision maker. The information provided in the following tables represents the primary measures used to assess segment performance by the Partnership's chief operating decision maker.

Reportable segment results of operations and financial position for the year ended December 31, 2018 are as follows (Note: "DD&A" refers to depreciation, depletion and amortization):

	Central Appalachia	Northern Appalachia	Rhino Western	Illinois Basin	Other	Total Consolidated
	(in thousands)					
Total assets	$ 92,605	$ 10,888	$ 30,028	$ 72,397	$ 42,700	$ 248,618
Total revenues	139,769	20,442	36,195	50,451	179	247,036
DD&A	8,747	1,221	4,098	7,910	366	22,342
Interest expense	1	-	-	-	8,482	8,483
Net Income (loss) from continuing operations	$ 8,777	$ (4,443)	$ 1,380	$ (7,690)	$ (14,055)	$ (16,031)

Reportable segment results of operations and financial position for the year ended December 31, 2017 are as follows:

	Central Appalachia	Northern Appalachia	Rhino Western	Illinois Basin	Other	Total Consolidated
	(in thousands)					
Total assets	$ 99,425	$ 9,054	$ 33,863	$ 77,546	$ 62,892	$ 282,780
Total revenues	101,992	17,145	35,458	64,055	41	218,691
DD&A	7,701	988	4,479	7,576	373	21,117
Interest expense	-	-	-	-	4,010	4,010
Net Income (loss) from continuing operations	$ 13,717	$ (3,109)	$ 1,676	$ 1,734	$ (34,638)	$ (20,620)

For additional information on the Partnership's revenue by product category for the periods ended December 31, 2018 and 2017 please refer to Note 17.

EMPLOYMENT AGREEMENT AMENDMENT

THIS EMPLOYMENT AGREEMENT AMENDMENT (this "Amendment") is entered into effective as of January 1, 2019 (the "Effective Date"), between **Rhino GP LLC** ("Employer") and **Chad Hunt** ("Employee").

W I T N E S S E T H

WHEREAS, Employee is currently employed by Employer pursuant to an Amended and Restated Employment Agreement dated August 31, 2014 (as amended, the "Prior Agreement").

WHEREAS, Employer and Employee now desire to amend the Prior Agreement, and have executed this Amendment to evidence the terms of their agreement.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the parties agree as follows:

1. Section 1 of the Prior Agreement is hereby deleted and replaced in its entirety with the following language:

*"**Terms of Employment.** Unless terminated earlier in accordance with the provisions of Section 7, Executive's employment under this Agreement shall be effective for a term commencing on the Effective Date and ending on December 31, 2019 (the "Employment Term")."*

2. The first sentence of Section 2 of the Prior Agreement is hereby deleted and replaced in its entirety with the following language:

"Executive shall serve as the Chief Administrative Officer of the Employer."

3. Section 3 of the Prior Agreement is hereby deleted and replaced in its entirety with the following language:

*"**Base Salary**. The Employer shall pay Executive a base salary (the "Base Salary") at the annual rate of $305,000, which Base Salary shall be evaluated annually for potential increase, payable in regular installments in accordance with the usual executive payroll practices of Employer."*

4. All other terms and conditions in the Prior Agreement shall remain unchanged except to the extent specifically modified herein.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, the parties hereto have executed and delivered this Amendment as of the day and year first above written.

EMPLOYER:

Rhino GP LLC

By: ***/s/ Richard A. Boone***

EMPLOYEE:

/s/ Chad Hunt
Chad Hunt

EMPLOYMENT AGREEMENT AMENDMENT

THIS EMPLOYMENT AGREEMENT AMENDMENT (this "Amendment") is entered into effective as of January 1, 2019 (the "Effective Date"), between **Rhino GP LLC** ("Employer") and **Scott Morris** ("Employee").

W I T N E S S E T H

WHEREAS, Employee is currently employed by Employer pursuant to an Employment Agreement dated October 1, 2015 (as amended, the "Prior Agreement").

WHEREAS, Employer and Employee now desire to amend the Prior Agreement, and have executed this Amendment to evidence the terms of their agreement.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the parties agree as follows:

1. The first sentence of Section 1 of the Prior Agreement is hereby deleted and replaced in its entirety with the following language:

"The Employer hereby shall employ Employee as its Chief Financial Officer and Senior Vice President continuing from the Effective Date until December 31, 2019, unless sooner terminated as herein provided or extended by mutual agreement of the parties (the "Employment Term"), with such duties customary to such position as Employer may reasonably designate during the Employment Term."

2. Section 2 of the Prior Agreement is hereby deleted and replaced in its entirety with the following language:

*"**Compensation**. For Employee's services hereunder during the Employment Term, Employer shall pay to Employee a salary at a rate of $237,500 per year ("Base Salary"), payable periodically in accordance with Employer's usual executive payroll payment procedures, subject to periodic review for possible increase."*

3. All other terms and conditions in the Prior Agreement shall remain unchanged except to the extent specifically modified herein.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, the parties hereto have executed and delivered this Amendment as of the day and year first above written.

EMPLOYER:

Rhino GP LLC

By: ***/s/ Richard A. Boone***

EMPLOYEE:

/s/ Scott Morris
Scott Morris

EMPLOYMENT AGREEMENT AMENDMENT

THIS EMPLOYMENT AGREEMENT AMENDMENT (this "Amendment") is entered into effective as of January 1, 2019 (the "Effective Date"), between **Rhino GP LLC** ("Employer") and **Brian Aug** ("Employee").

W I T N E S S E T H

WHEREAS, Employee is currently employed by Employer pursuant to an Employment Agreement dated November 21, 2016 (as amended, the "Prior Agreement").

WHEREAS, Employer and Employee now desire to amend the Prior Agreement, and have executed this Amendment to evidence the terms of their agreement.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the parties agree as follows:

1. The first sentence of Section 1 of the Prior Agreement is hereby deleted and replaced in its entirety with the following language:

"The Employer hereby shall employ Employee as its Vice President of Sales continuing from the Effective Date until December 31, 2019, unless sooner terminated as herein provided or extended by mutual agreement of the parties (the "Employment Term"), with such duties customary to such position as Employer may reasonably designate during the Employment Term."

2. Section 2 of the Prior Agreement is hereby deleted and replaced in its entirety with the following language:

*"**Compensation**. For Employee's services hereunder during the Employment Term, Employer shall pay to Employee a salary at a rate of $220,000 per year ("Base Salary"), payable periodically in accordance with Employer's usual executive payroll payment procedures, subject to periodic review for possible increase."*

3. As partial consideration for Employee entering into this Amendment, Employer agrees that, on or before October 1, 2019, Employer shall notify Employee whether it intends to extend the Employment Term for 2020, and shall provide Employee with the applicable agreement or amendment, if any.

4. All other terms and conditions in the Prior Agreement shall remain unchanged except to the extent specifically modified herein.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, the parties hereto have executed and delivered this Amendment as of the day and year first above written.

EMPLOYER:

Rhino GP LLC

By: ***/s/ Richard A. Boone***

EMPLOYEE:

/s/ Brian Aug
Brian Aug

Exhibit 21.1

Subsidiaries of Rhino Resource Partners LP

Entity	Jurisdiction of Organization
Rhino Energy LLC	Delaware
CAM Mining LLC	Delaware
Rhino Northern Holdings LLC	Delaware
Hopedale Mining LLC	Delaware
Castle Valley Mining LLC	Delaware
Pennyrile Energy LLC	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of

The Managing General Partner and Partners of

Rhino Resource Partners LP:

We consent to the incorporation by reference in Registration Statement 333-169714 on Form S-8 and Registration Statement No. 333-199263 on Form S-3 of Rhino Resource Partners LP of our report dated March 25, 2019, with respect to the consolidated statements of financial position of Rhino Resource Partners LP and Subsidiaries as of December 31, 2018 and 2017, and the related consolidated statements of operations and comprehensive income, partners' capital, and cash flows for each of the years in the two-year period ended December 31, 2018, appearing in this Annual Report on Form 10-K of Rhino Resource Partners LP for the year ended December 31, 2018.

CERTIFIED PUBLIC ACCOUNTANTS

513 State St.
Bristol, Virginia
March 25, 2019

CONSENT OF MARSHALL MILLER & ASSOCIATES, INC.

As mining and geological consultants, we hereby consent to the use by Rhino Resource Partners LP (the "Partnership") in connection with its Annual Report on Form 10-K for the year ended December 31, 2018 (the "Form 10-K"), and any amendments thereto, and to the incorporation by reference in the Partnership's Registration Statement on Form S-8 (No. 333-169714), and in the Partnership's Registration Statement on Form S-3 (File No. 333-199263) of information contained in our report dated January 17, 2019 in the Form 10-K. We also consent to the reference to Marshall Miller & Associates, Inc. in those filings and any amendments thereto.

By: */s/ Justin S. Douthat*
Marshall Miller & Associates, Inc.
Name: Justin S. Douthat
Title: Principal and Engineering Manager
Dated: March 22, 2019

By: */s/ J. Scott Nelson*
Marshall Miller & Associates, Inc.
Name: J. Scott Nelson
Title: Senior Principal
Dated: March 22, 2019

Exhibit 31.1

Certifications

I, Richard A. Boone, certify that:

1. I have reviewed this annual report on Form 10-K of Rhino Resource Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 25, 2019

/s/ RICHARD A. BOONE
Richard A. Boone
President, Chief Executive Officer and Director

Exhibit 31.2

Certifications

I, Wendell S. Morris, certify that:

1. I have reviewed this annual report on Form 10-K of Rhino Resource Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 25, 2019

/s/ Wendell S. Morris

Wendell S. Morris

Senior Vice President and Chief Financial Officer

Exhibit 32.1

**Certification of Chief Executive Officer Pursuant To
18 U.S.C. Section 1350, as Adopted Pursuant To
Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the Annual Report on Form 10-K of Rhino Resource Partners LP (the "Partnership") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Richard A. Boone, as Chief Executive Officer of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: */s/ Richard A. boone*
Name: Richard A. Boone
Title: *President, Chief Executive Officer and Director*

Date: March 25, 2019

Exhibit 32.2

Certification of Chief Financial Officer Pursuant To
18 U.S.C. Section 1350, as Adopted Pursuant To
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report on Form 10-K of Rhino Resource Partners LP (the "Partnership") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Wendell S. Morris, as Chief Financial Officer of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Wendell S. Morris
Wendell S. Morris
Senior Vice President and Chief Financial Officer

Date: March 25, 2019

Federal Mine Safety and Health Act Information

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (the "Mine Act"). The following disclosures respond to that legislation.

Whenever MSHA believes that a violation of the Mine Act, any health or safety standard, or any regulation has occurred, it may issue a citation that describes the violation and fixes a time within which the operator must abate the violation. In these situations, MSHA typically proposes a civil penalty, or fine, as a result of the violation, that the operator is ordered to pay. In evaluating the information below regarding mine safety and health, investors should take into account factors such as: (a) the number of citations and orders will vary depending on the size of a coal mine, (b) the number of citations issued will vary from inspector to inspector and mine to mine, and (c) citations and orders can be contested and appealed, and during that process are often reduced in severity and amount, and are sometimes dismissed.

Responding to the Dodd-Frank Act legislation, we report that, for the year ended December 31, 2018, none of our subsidiaries received written notice from MSHA of (a) a violation under section 110(b)(2) of the Mine Act for failure to make reasonable efforts to eliminate a known violation of a mandatory safety or health standard that substantially proximately caused, or reasonably could have been expected to cause, death or serious bodily injury, (b) a pattern of violations of mandatory health or safety standards under section 104(e) of the Mine Act, or (c) a violation under section 107(a) of the Mine Act for alleged conditions or practices that could reasonably be expected to cause death or serious physical harm. In addition, none of our subsidiaries suffered any mining related fatalities during the year ended December 31, 2018.

The following table sets out information required by the Dodd-Frank Act for the year ended December 31, 2018. The mine data retrieval system maintained by MSHA may show information that is different than what is provided herein. Any such difference may be attributed to the need to update that information on MSHA's system and/or other factors. The table also displays pending legal actions before the Federal Mine Safety and Health Review Commission (the "Commission") that were initiated during the year ended December 31, 2018 as well as total pending legal actions that were pending before the Commission as of December 31, 2018, which includes the legal proceedings before the Commission as well as all contests of citations and penalty assessments which are not before an administrative law judge. All of these pending legal actions constitute challenges by us of citations issued by MSHA. Since none of our subsidiaries received notice from MSHA of a pattern of violations of mandatory health or safety standards under section 104(e) of the Mine Act, the column that would normally display this information in the table below has been omitted for ease of presentation.

For the year ended December 31, 2018

Company	Mine[1]	MSHA ID	104(a) S & S [2]	104 (b)[3]	104 (d)[4]	107 (a)[5]	110 (b) (2)[6]	Proposed Assessments[7]	Pending Legal Proceedings[8]	Legal Proceedings Initiated	Legal Proceedings Resolved
Hopedale Mining LLC	Hopedale Mine	33-00968	24	0	0	0	0	$ 31,624	0	0	0
	Nelms Plant	33-04187	2	0	0	0	0	$ 1,665	0	0	0
CAM/Deane Mining LLC	Mine #28	15-18911	23	0	0	0	0	$ 49,420	1	1	0
	Three Mile Mine #1	15-17659	0	0	0	0	0	$ 0	0	0	0
	Right Fork-Rob Fork Contour	15-18977	7	0	0	0	0	$ 2,908	0	0	0
	Grapevine South	46-08930	10	0	0	0	0	$ 12,957	2	2	9
	Remining No. 3	46-09345	19	1	0	0	0	$ 35,262	2	4	2
	Rob Fork Processing	15-14468	16	0	3	0	0	$ 14,962	0	2	2
	Jamboree Loadout	15-12896	2	0	0	0	0	$ 1,067	0	0	0
	CAM Highwall Miner	46-09545	1					$ 1,117			
	Mill Creek Prep Plant	15-16577	0	0	0	0	0	$ -	0	0	0
	Tug Fork Plant	46-08626	3	0	0	0	0	$ 3,149	0	0	0
	Rhino Trucking	Q569	0	0	0	0	0	$ -	0	0	0
	Rhino Reclamation Services	R134	0	0	0	0	0	$ -	0	0	0
	Rhino Services	S359	0	0	0	0	0	$ -	0	0	0
Rhino Eastern LLC	Eagle #1	4608758	0	0	0	0	0	$ -	0	0	0
	Eagle #3	4609427	0	0	0	0	0	$ -	0	0	0
Pennyrile Energy LLC	Riveredge Mine	15-19424	73	0	0	0	0	$ 175,541	1	1	6
	Riveredge Surface Ops	15-19749	12	0	0	0	0	$ 4,102	0	0	0
McClane Canyon Mining LLC	McClane Canyon Mine	05-03013	0	0	0	0	0	$ -	0	0	0
Castle Valley Mining LLC	Castle Valley Mine #3	42-02263	2	0	0	0	0	$ 4,627	0	0	0
	Castle Valley Mine #4	42-02335	10	0	0	0	0	$ 23,595	2	2	0
	Bear Canyon Loading Facility	42-02395	4	0	0	0	0	$ 8,201	1	1	2
Total			208	1	3	0	0	$ 370,197	9	13	21

[1] The foregoing table does not include the following: (i) facilities which have been idle or closed unless they received a citation or order issued by MSHA; and (ii) permitted mining sites where we have not begun operations and therefore have not received any citations.

[2] Mine Act section 104(a) citations shown above are for alleged violations of health or safety standards that could significantly and substantially contribute to a serious injury if left unabated.

[3] Mine Act section 104(b) orders are for alleged failures to totally abate a citation within the period of time specified in the citation. These orders result in an order of immediate withdrawal from the area of the mine affected by the condition until MSHA determines that the violation has been abated.

[4] Mine Act section 104(d) citations and orders are for an alleged unwarrantable failure (i.e. aggravated conduct constituting more than ordinary negligence) to comply with a mandatory mining health or safety standard or regulation. These types of violations could significantly and substantially contribute to a serious injury; however, the conditions do not cause imminent danger.

[5] Mine Act section 107(a) orders are for alleged conditions or practices which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated and result in orders of immediate withdrawal from the area of the mine affected by the condition.

[6] The total number of flagrant violations issued under section 110(b)(2) of the Mine Act.

[7] Total dollar value of MSHA assessments proposed during the year ended December 31, 2018.

[8] Any pending legal action before the Federal Mine Safety and Health Review Commission (the "Commission") involving a coal mine owned and operated by us. The number of legal actions pending as of December 31, 2018 that fall into each of the following categories is as follows:

(a) Contests of citations and orders: 9

(b) Contests of proposed penalties: 0

(c) Complaints for compensation under Section 111 of the Mine Act: 0

(d) Complaints of discharge, discrimination or interference under Section 105 of the Mine Act: 0

(e) Applications for temporary relief under Section 105(b)(2) of the Mine Act: 0

(f) Appeals of judges' decisions or orders to the Commission: 0

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