2019
ANNUAL REPORT

ALLIANCE RESOURCE PARTNERS, L.P.

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2019

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 NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	73-1564280 (IRS Employer Identification No.)

1717 South Boulder Avenue, Suite 400, Tulsa, Oklahoma 74119

(Address of Principal Executive Offices and Zip Code)

(918) 295-7600

(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Trading Symbol**	**Name of Each Exchange On Which Registered**
Common Units representing limited partner interests	ARLP	The NASDAQ Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act: None

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

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

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 ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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, a smaller reporting company, or an emerging growth 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 smaller reporting company)	Smaller Reporting Company ☐

Emerging Growth Company ☐

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

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

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $1,809,240,225 as of June 28, 2019, the last business day of the registrant's most recently completed second fiscal quarter, based on the reported closing price of the common units as reported on The NASDAQ Stock Market LLC on such date.

As of February 20, 2020, 127,195,219 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

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GLOSSARY OF COAL TERMS

The following are abbreviations and definitions of certain terms used in this document, some of which are defined by authoritative sources and others reflect those we commonly use in the coal industry:

Assigned reserves	Reserves that have been designated for mining by a specific operation
Bituminous coal	Coal used primarily to generate electricity and to make coke for the steel industry with a heat value ranging between 10,500 and 15,500 Btus per pound
Btu	British thermal unit
Compliance coal	Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per MMBtus, requiring no blending or other sulfur dioxide reduction technologies in order to comply with the requirements of the Federal Clean Air Act
Continuous miner	A machine used in underground mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation
High-sulfur coal	Based on market on market expectations, we classify coal with a sulfur content of greater than 3%.
Long-term contracts	Contracts having a term of one year or greater
Longwall mining	One of two major underground coal mining methods, utilizing specialized equipment to remove nearly all of a coal seam over a very large area
Low-sulfur coal	Based on market on market expectations, we classify coal with a sulfur content of less than 1.5%.
Medium-sulfur coal	Based on market on market expectations, we classify coal with a sulfur content of 1.5% to 3%.
Metallurgical coal	Coal primarily used in the production of steel
MMBtus	Million British thermal units
Preparation plant	A facility used for crushing, sizing, and washing coal to remove impurities and to prepare it for use by a particular customer
Probable reserves	As defined by the Securities and Exchange Commissions ("SEC") Industry Guide 7, probable reserves are reserves for which quantity and grade and/or quality are computed from information similar to that used for proven 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 reserves, is high enough to assume continuity between points of observation.
Proven reserves	As defined by the SEC Industry Guide 7, proven reserves are 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 restoration of land and environmental standards to a mining site after the coal is extracted, including returning the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers
Reserves	As defined by the SEC Industry Guide 7, reserves are that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Our references to reserves in this report take into account estimated losses involved in producing a saleable product (i.e., salable reserves).
Room-and-pillar mining	One of two major underground coal mining methods, utilizing continuous miners creating a network of "rooms" within a coal seam, leaving behind "pillars" of coal used to support the roof of a mine
Thermal coal	Coal used primarily in the generation of electricity
Unassigned reserves	Reserves that have not yet been designated for mining by a specific operation

GLOSSARY OF OIL & GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, some of which are defined by authoritative sources and others reflect those we commonly use in the oil & gas industry:

Basin	A depression in the crust of the Earth, caused by plate tectonic activity and subsidence, in which sediments accumulate. If rich hydrocarbon source rocks occur in combination with appropriate depth and duration of burial, then a petroleum system can develop within the basin. Most basins contain some amount of shale, thus providing opportunities for shale oil & gas exploration and production.
Basis differential	The difference between the spot price of a commodity and the sales price at the delivery point where the commodity is sold
Bbl	Stock tank barrel, or 42 United States gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons
BOE	Barrels of oil equivalent, with six Mcf of natural gas being equivalent to one Bbl of crude oil, condensate or natural gas liquids.
Developed acreage	Acreage allocated or assignable to productive wells
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids
Mcf	Thousand cubic feet of natural gas
MMcf	Million cubic feet of natural gas
Mineral Interest	Mineral interests are real-property interests that are typically perpetual and grant ownership to the oil & gas under a tract of land or the rights to explore for, develop, and produce oil & gas on that land or to lease those exploration and development rights to a third party.
Net acres	The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres
Net royalty acres	Mineral ownership standardized to a 12.5%, or 1/8th, royalty interest
NGLs	Natural gas liquids are components of natural gas that are liquid at surface in field facilities or in gas-processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure. Natural gas liquids include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied. The term is commonly abbreviated as NGL.
Oil & gas	Crude oil, natural gas and natural gas liquids
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease

Productive well	A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes
Proved developed reserves	Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods
Proved reserves or properties	Proved reserves are those quantities of oil & gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. See Exhibit 99.1 for the complete SEC definition.
Proved undeveloped reserves	Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion
PUD	Proved undeveloped reserves
Reserves	As defined by the SEC, reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible.
Royalty interest	An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development or operations
Undeveloped acreage	Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil & gas regardless of whether such acreage contains proved reserves
Unproved reserves or properties	The SEC defines unproved reserves as properties with no proved reserves. We also consider unproved reserves or properties to be defined as the estimated quantities of oil & gas determined based on geological and engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved.

FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K may constitute "forward-looking statements." These statements are based on our beliefs as well as assumptions made by, and information currently available to, us. When used in this document, the words "anticipate," "believe," "continue," "estimate," "expect," "forecast," "may," "project," "will," and similar expressions identify forward-looking statements. Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- decline in the coal industry's share of electricity generation, including as a result of environmental concerns related to coal mining and combustion and the cost and perceived benefits of other sources of electricity and fuels, such as oil & gas, nuclear energy, and renewable fuels;
- changing global economic conditions or in industries in which our customers operate;
- changes in coal prices and/or oil & gas prices, demand and availability which could affect our operating results and cash flows;
- changes in competition in domestic and international coal markets and our ability to respond to such changes;
- risks associated with the expansion of our operations and properties;
- our ability to identify and complete acquisitions;
- dependence on significant customer contracts, including renewing existing contracts upon expiration;
- adjustments made in price, volume, or terms to existing coal supply agreements;
- recent action and the possibility of future action on trade made by United States and foreign governments;
- the effect of new tariffs and other trade measures;
- legislation, regulations, and court decisions and interpretations thereof, both domestic and foreign, including those relating to the environment and the release of greenhouse gases, mining, miner health and safety, hydraulic fracturing, and health care;
- deregulation of the electric utility industry or the effects of any adverse change in the coal industry, electric utility industry, or general economic conditions;
- liquidity constraints, including those resulting from any future unavailability of financing;
- customer bankruptcies, cancellations or breaches to existing contracts, or other failures to perform;
- customer delays, failure to take coal under contracts or defaults in making payments;
- our productivity levels and margins earned on our coal sales;
- disruptions to oil & gas exploration and production operations at the properties in which we hold mineral interests;
- changes in raw material costs;
- changes in the availability of skilled labor;
- our ability to maintain satisfactory relations with our employees;
- increases in labor costs including costs of health insurance and taxes resulting from the Affordable Care Act, adverse changes in work rules, or cash payments or projections associated with workers' compensation claims;
- increases in transportation costs and risk of transportation delays or interruptions;
- operational interruptions due to geologic, permitting, labor, weather-related or other factors;
- risks associated with major mine-related accidents, mine fires, mine floods or other interruptions;
- results of litigation, including claims not yet asserted;
- foreign currency fluctuations that could adversely affect the competitiveness of our coal abroad;
- difficulty maintaining our surety bonds for mine reclamation as well as workers' compensation and black lung benefits;
- difficulty in making accurate assumptions and projections regarding post-mine reclamation as well as pension, black lung benefits, and other post-retirement benefit liabilities;
- uncertainties in estimating and replacing our coal reserves;
- uncertainties in estimating and replacing our oil & gas reserves;
- uncertainties in the amount of oil & gas production due to the level of drilling and completion activity by the operators of our oil & gas properties;

- the impact of current and potential changes to federal or state tax rules and regulations, including a loss or reduction of benefits from certain tax deductions and credits;
- difficulty obtaining commercial property insurance, and risks associated with our participation in the commercial insurance property program;
- evolving cybersecurity risks, such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions;
- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with equity investments in companies we do not control; and
- other factors, including those discussed in "Item 1A. Risk Factors" and "Item 3. Legal Proceedings."

If one or more of these or other risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind the risk factors described in "Item 1A. Risk Factors" below. The risk factors could also cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

You should consider the information above when reading any forward-looking statements contained in this Annual Report on Form 10-K; other reports filed by us with the United States Securities and Exchange Commission ("SEC"); our press releases; our website ***http://www.arlp.com***; and written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

Significant Relationships Referenced in this Annual Report

- References to "we," "us," "our" or "ARLP Partnership" mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.
- References to "ARLP" mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.
- References to "MGP" mean Alliance Resource Management GP, LLC, ARLP's sole general partner and, prior to the Exchange Transaction discussed below, it was also referred to as the managing general partner to distinguish MGP from SGP. As a result of the Exchange Transaction, SGP no longer holds any general partner interests.
- References to "SGP" mean Alliance Resource GP, LLC, ARLP's special general partner prior to the Exchange Transaction discussed below. SGP is indirectly wholly owned by Joseph W. Craft III, the Chairman, President and Chief Executive Officer ("CEO") of MGP, and Kathleen S. Craft, who are collectively referred to in such capacity as the "Owners of SGP." The Owners of SGP held approximately 34.48% of the outstanding AHGP common units prior to the Simplification Transactions discussed below.
- References to "Intermediate Partnership" mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P.
- References to "Alliance Coal" mean Alliance Coal, LLC, the holding company for the coal mining operations of Alliance Resource Operating Partners, L.P.
- References to "AHGP" mean Alliance Holdings GP, L.P., individually and not on a consolidated basis as the parent company of MGP prior to the Simplification Transactions discussed below and as a wholly owned subsidiary of ARLP subsequent to the Simplification Transactions.

PART I

ITEM 1. BUSINESS

<u>General</u>

Introduction

We are a diversified natural resource company that generates income from coal production and oil & gas mineral interests located in strategic producing regions across the United States. The primary focus of our business is to maximize the value of our existing mineral assets, both in the production of coal from our mining assets and the leasing and development of our oil & gas mineral ownership. We believe that ARLP's diverse and rich resource base will allow ARLP to continue to create long-term value for unitholders.

We are currently the second largest coal producer in the eastern United States with seven underground mining complexes in Illinois, Indiana, Kentucky, Maryland and West Virginia as well as a coal-loading terminal in Indiana. We manage and report our coal operations primarily under two regions, Illinois Basin and Appalachia. We market our coal production to major domestic and international utilities and industrial users.

We currently own both mineral and royalty interests in approximately 1.4 million gross acres in premier oil & gas producing regions in the United States, primarily the Permian, Anadarko and Williston Basins. While we own both mineral and royalty interests, we refer to them collectively as mineral interests throughout our discussions of our business as the majority of our holdings are mineral interests. We market our mineral interests for lease to operators in those regions and generate royalty income from the leasing and development of those mineral interests. Reserve additions and the associated cash flows are expected to increase from the development of our existing mineral interests and through acquisitions of additional mineral interests.

In addition, we provide terminal services for the transloading of coal, and develop and market industrial and mining technology products and services.

ARLP, a Delaware limited partnership, completed its initial public offering on August 19, 1999 and is listed on the NASDAQ Global Select Market under the ticker symbol "ARLP." We are managed by our sole general partner, MGP, a Delaware limited liability company, which holds a non-economic general partner interest in ARLP.

Simplification Transactions

On July 28, 2017, the conflicts committee ("Conflicts Committee") of the board of directors ("Board of Directors") of MGP and AGP's board of directors approved a transaction to simplify our partnership structure. Pursuant to that transaction, which closed on the same date, MGP contributed to ARLP all of its incentive distribution rights ("IDRs") and its 0.99% managing general partner interest in ARLP in exchange for 56,100,000 ARLP common units and a non-economic general partner interest in ARLP. In conjunction with this transaction and on the same economic basis as MGP, SGP also contributed to ARLP its 0.01% general partner interest in both ARLP and the Intermediate Partnership in exchange for 28,141 ARLP common units collectively (the "Exchange Transaction").

On February 22, 2018, our Board of Directors and the board of directors of AHGP's general partner approved a simplification agreement (the "Simplification Agreement") pursuant to which, among other things, through a series of transactions (the "Simplification Transactions"):

i. AHGP would become a wholly owned subsidiary of ARLP,
ii. all of the issued and outstanding AHGP common units would be canceled and converted into the right to receive the ARLP common units held by AHGP and its subsidiaries,
iii. in exchange for a number of ARLP common units calculated pursuant to the Simplification Agreement, MGP's 1.0001% general partner interest in our Intermediate Partnership and MGP's 0.001% managing member interest in our subsidiary, Alliance Coal, would be contributed to us, and
iv. MGP would remain ARLP's sole general partner and would be a wholly owned subsidiary of AGP, and thus no control, management, or governance changes with respect to our business would occur.

The Simplification Agreement and the transactions contemplated thereby were approved by the written consent of approximately 68% of the holders of AHGP common units outstanding as of April 25, 2018, the record date for the consent solicitation. On May 31, 2018, ARLP, AHGP, and the other parties to the Simplification Agreement completed the transactions contemplated by the Simplification Agreement.

Prior to the Simplification Transactions, MGP was a wholly owned indirect subsidiary of AHGP. Alliance GP, LLC ("AGP"), which is indirectly wholly owned by Mr. Craft, was the general partner of AHGP prior to the Simplification Transactions and became the direct owner of MGP as a result of those transactions. See discussions under Partnership Simplification regarding changes in ownership of ARLP and MGP as a result of the Exchange Transaction and Simplification Transactions.

As part of the Simplification Transactions, (i) each AHGP common unit that was issued and outstanding at the effective time of the Simplification Transactions was canceled and converted into the right to receive a portion of the ARLP common units held by AHGP and its subsidiaries, and (ii) SGP became the sole limited partner in AHGP. Each outstanding AHGP common unit, other than certain AHGP common units held by the Owners of SGP, converted into the right to receive approximately 1.4782 ARLP common units held by AHGP and its subsidiaries. The remaining AHGP common units held by the Owners of SGP were canceled and converted into the right to receive 29,188,997 ARLP common units which equaled (i) the product of the number of certain AHGP common units held by the Owners of SGP multiplied by 1.4782, minus (ii) 1,322,388 ARLP common units. In addition, ARLP issued 1,322,388 ARLP common units to the Owners of SGP in exchange for causing SGP to contribute to ARLP its remaining limited partner interest in AHGP, which included AHGP's indirect ownership of a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal, resulting in an overall exchange ratio to the Owners of SGP equal to that of the other AHGP unitholders. Upon the issuance of ARLP common units to the Owners of SGP in exchange for the limited partner interest in AHGP, ARLP became a) the sole limited partner of AHGP and b) through AHGP, the indirect owner of a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal.

AllDale I & II Acquisition

On January 3, 2019 (the "Acquisition Date"), ARLP acquired the general partner interests and all of the limited partner interests not owned by Cavalier Minerals JV, LLC ("Cavalier Minerals") in AllDale Minerals, LP ("AllDale I") and AllDale Minerals II, LP ("AllDale II", and collectively with AllDale I, "AllDale I & II") for $176.2 million, which was funded with cash on hand and borrowings under our revolving credit facility (the "AllDale Acquisition"). ARLP indirectly owns a 96.0% non-managing member interest and a non-economic managing member interest in Cavalier Minerals. The

AllDale Acquisition provides ARLP with diversified exposure to industry leading operators and is consistent with our general business strategy to pursue accretive acquisitions.

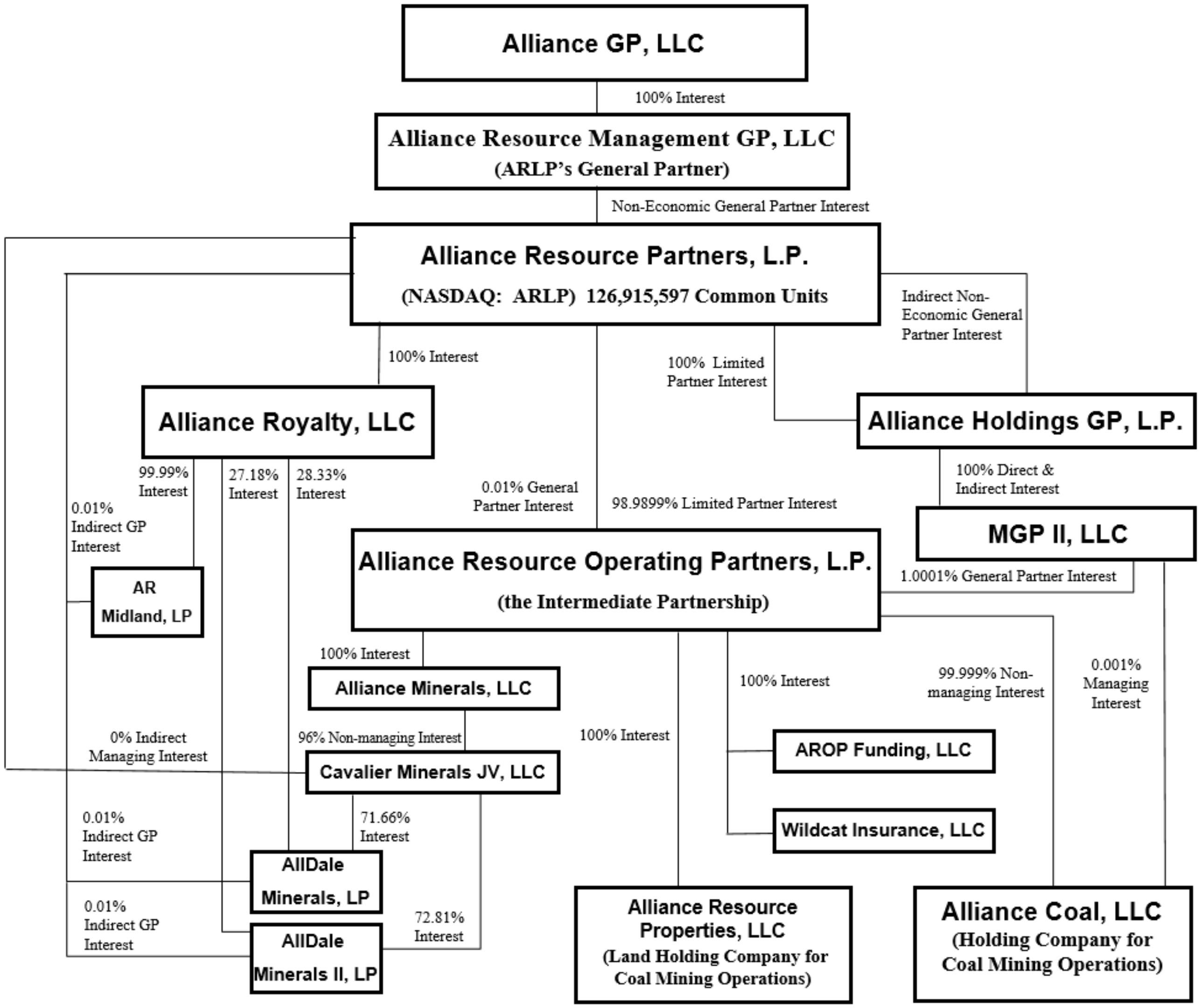
Kodiak Redemption

On January 26, 2019, Kodiak Gas Services, LLC ("Kodiak") provided notification that it intended to redeem our preferred interest for $135.0 million, which is inclusive of an early redemption premium. On February 8, 2019, we received the cash proceeds of the redemption.

Wing Acquisition

On August 2, 2019, our subsidiary AR Midland, LP ("AR Midland") acquired from Wing Resources LLC and Wing Resources II LLC (collectively, "Wing") approximately 9,000 net royalty acres in the Midland Basin, with exposure to more than 400,000 gross acres (the "Wing Acquisition"). The Wing Acquisition enhanced our ownership position in the Permian Basin, expanded our exposure to industry leading operators, and furthered our business strategy to grow our Minerals segment. Following the Wing Acquisition, we hold approximately 55,700 net royalty acres in premier oil & gas resource plays including net royalty acres from our investment in AllDale Minerals III, LP ("AllDale III"). See "Item 8. Financial Statements and Supplementary Data—Note 3 – Acquisitions" for more information.

The following diagram depicts our simplified organization and ownership as of December 31, 2019:



Our internet address is *http://www.arlp.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, Forms 3, 4 and 5 for our Section 16 filers and other documents (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. 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.

The SEC maintains a website that contains reports, proxy and information statements, and other information for issuers, including us. The public can obtain any documents that we file with the SEC at *http://www.sec.gov*.

Coal Mining Operations

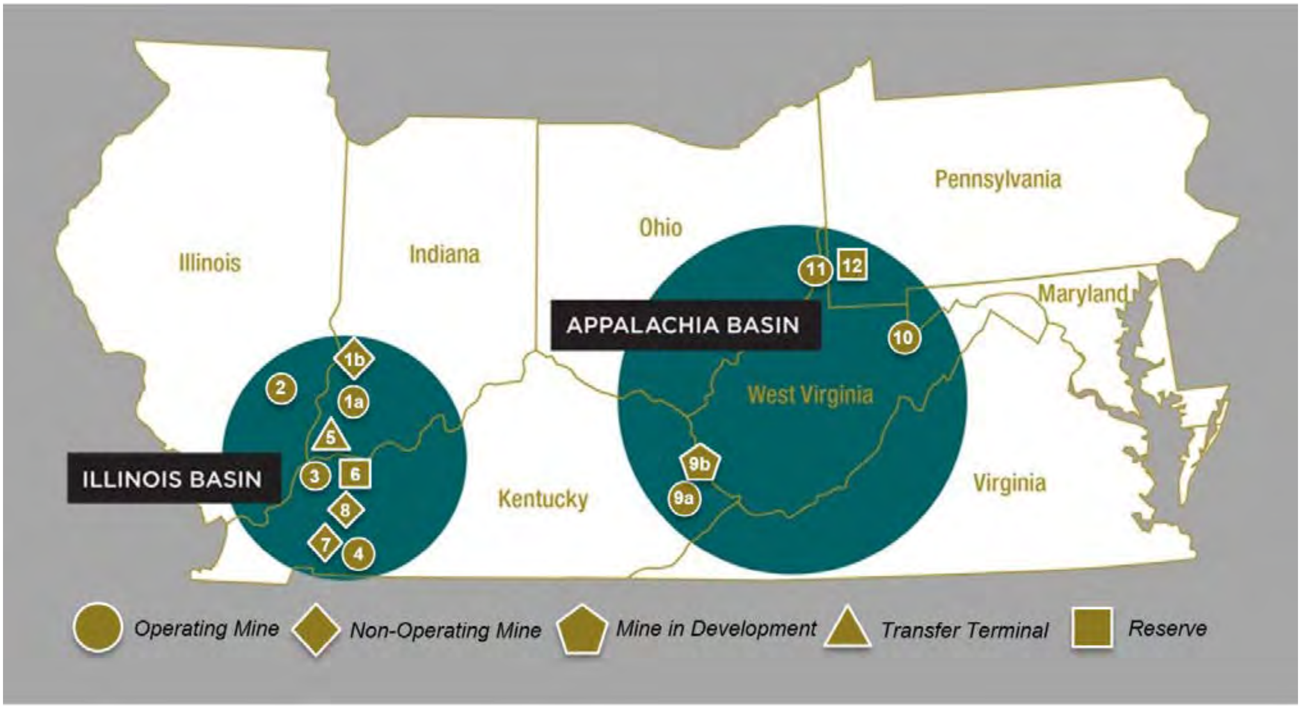
Coal is used primarily for the generation of electric power and production of steel but is also used for chemical, food, and cement processing. We produce bituminous coal from our underground mines that is sold to customers principally for electric power generation (thermal) and for production of steel (metallurgical). We have established long-term relationships with customers through exemplary and consistent performance while operating our mines with an industry-leading safety record.

At December 31, 2019, we had approximately 1.7 billion tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. We produce a diverse range of thermal and metallurgical coal with varying sulfur and heat contents, which enables us to satisfy the broad range of specifications required by our customers. In 2019, we sold 39.3 million tons of coal and produced 40.0 million tons. The coal we sold in 2019 was approximately 26.2% low-sulfur coal, 65.2% medium-sulfur coal and 8.6% high-sulfur coal. In 2019, approximately 78.8% of our tons sold were purchased by United States electric utilities and 17.9% were sold into the international markets through brokered transactions. The balance of our tons sold were to third-party resellers and industrial consumers. For tons sold to United States electric utilities, 100% were sold to utility plants with installed pollution control devices. The Btu content of our coal ranges from 11,400 to 13,200.

The following chart summarizes our coal production by region for the last five years.

	Year Ended December 31,				
Coal Regions	**2019**	**2018**	**2017**	**2016**	**2015**
	(tons in millions)				
Illinois Basin	29.5	29.9	27.3	25.4	32.0
Appalachia	10.5	10.4	10.3	9.8	9.2
Total	40.0	40.3	37.6	35.2	41.2

The following map shows the location of our coal mining operations:



Illinois Basin Operations:

1. GIBSON COMPLEX
a. Gibson South Mine
b. Gibson North Mine (Idled)
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Low/Medium-Sulfur
Transportation: Barge, Railroad & Truck

2. HAMILTON COMPLEX
Hamilton Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall & Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge, Railroad & Truck

3. RIVER VIEW COMPLEX
River View Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge & Truck

4. WARRIOR COMPLEX
Warrior Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge, Railroad, & Truck

5. MOUNT VERNON TRANSFER TERMINAL
Rail or Truck to Ohio River Barge Transloading Facility

6. HENDERSON/UNION RESERVES
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge & Truck

7. DOTIKI COMPLEX
Dotiki Mine (closed)
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge, Railroad & Truck

8. SEBREE-ONTON COMPLEX
Onton Mine (Idled)
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge & Truck

Appalachian Operations:

9. MC MINING COMPLEX
a. Excel Mine No. 4
b. Excel Mine No. 5 (in development)
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Low-Sulfur
Transportation: Barge, Railroad, & Truck

10. METTIKI COMPLEX
Mountain View Mine
Mining Type: Underground
Mining Access: Slope
Mining Method: Longwall & Continuous Miner
Coal Type: Low/Medium Sulfur - Metallurgical
Transportation: Railroad & Truck

11. TUNNEL RIDGE COMPLEX
Tunnel Ridge Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall & Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge & Railroad

12. PENN RIDGE RESERVES
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall & Continuous Miner
Coal Type: High-Sulfur
Transportation: Barge & Railroad & Continuous Miner

We lease most of our coal reserves and generally have the right to maintain leases in force until the exhaustion of mineable and merchantable coal located within the leased premises or a larger coal reserve area. These leases provide for royalties to be paid to the lessors at a fixed amount per ton or as a percentage of the sales price. Many leases require payment of minimum royalties, payable either at the time of the execution of the lease or in periodic installments, even if no mining activities have begun. These minimum royalties are normally credited against the production royalties owed to a lessor once coal production has commenced.

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. As of December 31, 2019, we had 2,280 employees, and we operate four active mining complexes in the Illinois Basin.

Gibson Complex. Our subsidiary, Gibson County Coal, LLC ("Gibson County Coal"), operates the Gibson South mine, located near the city of Princeton in Gibson County, Indiana. The Gibson South mine is an underground mine and utilizes continuous mining units employing room-and-pillar mining techniques to produce low/medium-sulfur coal. The Gibson South mine's preparation plant has throughput capacity of 1,800 tons of raw coal per hour. Production from the Gibson South mine is shipped by truck on United States and state highways or transported by rail on the CSX Transportation, Inc. ("CSX") and Norfolk Southern Railway Company ("NS") railroads from the Gibson North rail loadout facility directly to customers or to various transloading facilities, including our Mt. Vernon Transfer Terminal, LLC ("Mt. Vernon") transloading facility, for barge delivery. Production from the mine began in April 2014.

Gibson County Coal also operates the Gibson North mine, an underground mine also located near the city of Princeton in Gibson County, Indiana. The Gibson North mine began production in November 2000 and utilizes continuous mining units employing room-and-pillar mining techniques to produce low/medium-sulfur coal. The Gibson North mine was idled in December 2015 in response to market conditions but resumed production in May 2018. In November 2019, the Gibson North mine was again idled in response to market conditions. The Gibson North mine's preparation plant has throughput capacity of 700 tons of raw coal per hour. Production from the Gibson North mine is shipped by truck on United States and state highways or transported by rail on the CSX and NS railroads directly to customers or to various transloading facilities for barge delivery.

Hamilton Complex. Our subsidiary, Hamilton County Coal, LLC ("Hamilton"), operates the Hamilton mine, located near the city of McLeansboro in Hamilton County, Illinois. The Hamilton mine is an underground longwall mining operation producing medium/high-sulfur coal from the Herrin No. 6 seam. Initial development production from the continuous miner units began in 2013, longwall mining began in October 2014 and we acquired complete ownership and control in 2015. Hamilton's preparation plant has throughput capacity of 2,000 tons of raw coal per hour. Hamilton has the ability to ship production from the Hamilton mine via the CSX, Evansville Western Railway and NS rail directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries.

River View Complex. Our subsidiary, River View Coal, LLC ("River View"), operates the River View mine, which is located in Union County, Kentucky and is currently the largest room-and-pillar coal mine in the United States. The River View mine began production in 2009, and utilizes continuous mining units to produce medium/high-sulfur coal. River View's preparation plant has throughput capacity of 2,700 tons of raw coal per hour. Coal produced from the River View mine is transported by overland belt to a barge loading facility on the Ohio River.

Warrior Complex. Our subsidiary, Warrior Coal, LLC ("Warrior"), operates an underground mining complex located near the city of Madisonville in Hopkins County, Kentucky. The Warrior complex was opened in 1985, and we acquired it in February 2003. Warrior utilizes continuous mining units employing room-and-pillar mining techniques to produce medium/high-sulfur coal. Warrior's preparation plant has throughput capacity of 1,200 tons of raw coal per hour. Warrior's production is shipped via the CSX and Paducah & Louisville Railway, Inc. ("PAL") railroads and by truck on United States and state highways directly to customers or potentially to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries.

Mt. Vernon Transfer Terminal, LLC. Our subsidiary, Mt. Vernon, leases land and operates a coal-loading terminal on the Ohio River at Mt. Vernon, Indiana. Coal is delivered to Mt. Vernon by both rail and truck. The terminal has a capacity of 8.0 million tons per year with existing ground storage of approximately 200,000 tons. During 2019, the terminal loaded approximately 3.9 million tons for customers of Gibson County Coal and Hamilton.

Alliance Resource Properties. Alliance Resource Properties, LLC ("Alliance Resource Properties") and its subsidiaries own or control coal reserves that it leases to certain of our subsidiaries that operate our mining complexes. In December 2014 and February 2015, WKY CoalPlay, LLC or its subsidiaries ("WKY CoalPlay"), which are related parties, entered into coal lease agreements with us regarding coal reserves located in Henderson and Union Counties, Kentucky

("Henderson/Union Reserves") and Webster County, Kentucky. For more information about the WKY CoalPlay transactions, please read "Item 8. Financial Statements and Supplementary Data — Note 20 – Related-Party Transactions."

Dotiki Complex. Our subsidiary, Webster County Coal, LLC ("Webster County Coal"), operated Dotiki, an underground mining complex located near the city of Providence in Webster County, Kentucky. The complex was opened in 1966, and we purchased the mine in 1971 and operated it until it ceased production in August 2019. For information regarding Dotiki's' remaining coal reserves, please read "Item 2. Properties – Coal Reserves."

Hopkins Complex. The Hopkins complex, which we acquired in January 1998, is located near the city of Madisonville in Hopkins County, Kentucky. Our subsidiary, Hopkins County Coal, LLC ("Hopkins County Coal") operated the Elk Creek underground mine until it ceased production in April 2016. For information regarding Hopkins' remaining coal reserves, please read "Item 2. Properties Coal Reserves."

Pattiki Complex. Our subsidiary, White County Coal, LLC ("White County Coal"), operated Pattiki, an underground mining complex located near the city of Carmi in White County, Illinois. We began construction of the complex in 1980 and operated it until it ceased production in December 2016. We have begun performing reclamation activities at the complex. For information regarding Pattiki's remaining coal reserves, please read "Item 2. Properties – Coal Reserves."

Sebree - Onton Complex. On April 2, 2012, we acquired substantially all of Green River Collieries, LLC's assets related to its coal mining business and operations located in Webster and Hopkins Counties, Kentucky, including the Onton No. 9 mining complex ("Onton mine"). The Onton mine was operated by our subsidiary, Sebree Mining, LLC ("Sebree"). The Onton mine was idled in November 2015 in response to market conditions. For information regarding Onton's remaining coal reserves, please read "Item 2. Properties – Coal Reserves."

Appalachian Operations

Our Appalachian mining operations are located in eastern Kentucky, Maryland and West Virginia. As of December 31, 2019, we had 884 employees, and we operate three mining complexes in Appalachia with one mine currently under development.

MC Mining Complex. The MC Mining Complex is located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. Our subsidiary, MC Mining, LLC ("MC Mining"), owns the mining complex and controls the reserves, and our subsidiary, Excel Mining, LLC ("Excel") conducts all mining operations. The underground operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has throughput capacity of 1,000 tons of raw coal per hour. Substantially all of the coal produced at MC Mining in 2019 met or exceeded the compliance requirements of Phase II of the Federal Clean Air Act ("CAA") (see "—Environmental, Health and Safety Regulations—*Air Emissions*" below). Coal produced from the mine is shipped via the CSX railroad directly to customers or to various transloading facilities on the Ohio River for barge deliveries, or by truck via United States and state highways directly to customers or to various docks on the Big Sandy River for barge deliveries. MC Mining's Excel Mine No. 4 is anticipated to deplete its reserves in 2020.

Our subsidiary, Excel, has completed most development activity for MC Mining's Excel Mine No. 5 and currently anticipates transitioning employees and equipment to the new mine by mid-2020. MC Mining controls the estimated 15 million tons of coal reserves assigned to the Excel Mine No. 5 and Excel will conduct all mining operations. The underground operation will utilize continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal with an expected annual production capacity of 1.3 million tons. MC Mining plans to utilize its existing underground mining equipment and preparation plant to produce and process coal from the Excel Mine No. 5 and expects to ship coal produced from the mine to various transloading facilities on the Ohio River and the Big Sandy River for barge deliveries or directly to customers via the CSX railroad and by truck. We expect the development plan for the new Excel Mine No. 5 will provide a seamless transition from the current MC Mining operation.

Mettiki Complex. The Mettiki Complex ("Mettiki") comprises the Mountain View mine located in Tucker County, West Virginia operated by our subsidiary Mettiki Coal (WV), LLC ("Mettiki (WV)") and a preparation plant located near the city of Oakland in Garrett County, Maryland operated by our subsidiary Mettiki Coal, LLC ("Mettiki (MD)"). Mettiki (WV) began continuous miner development of the Mountain View mine in July 2005 and began longwall mining in November 2006. The Mountain View mine produces medium-sulfur coal, which is transported by truck either to the Mettiki (MD) preparation plant for processing for shipment into the metallurgical coal market or otherwise, or directly to the coal blending facility at the Virginia Electric and Power Company Mt. Storm Power Station. The Mettiki (MD) preparation plant has throughput capacity of 1,350 tons of raw coal per hour. Coal processed at the preparation plant can be trucked to the blending facility at Mt. Storm or shipped via the CSX railroad, which provides the opportunity to ship into the domestic and international thermal and metallurgical coal markets.

Tunnel Ridge Complex. Our subsidiary, Tunnel Ridge, LLC ("Tunnel Ridge"), operates the Tunnel Ridge mine, an underground longwall mine in the Pittsburgh No. 8 coal seam, located near Wheeling, West Virginia. Tunnel Ridge began construction of the mine and related facilities in 2008. Development mining began in 2010, and longwall mining operations began at Tunnel Ridge in May 2012. The Tunnel Ridge preparation plant has throughput capacity of 2,000 tons of raw coal per hour. Coal produced from the Tunnel Ridge mine is a medium/high-sulfur coal and is transported by conveyor belt to a barge loading facility on the Ohio River. Tunnel Ridge has the ability through a third-party facility to transload coal from barges for rail shipment on the Wheeling and Lake Erie Railway with connections to the CSX and the NS railroads.

Penn Ridge. Our subsidiary, Penn Ridge Coal, LLC ("Penn Ridge"), holds coal reserves in Washington County, Pennsylvania, estimated to include approximately 61.5 million tons of proven and probable high-sulfur coal in the Pittsburgh No. 8 seam. Development of the project is regulatory and market dependent, and its timing is open-ended pending obtaining all required regulatory approvals, sufficient coal sales commitments to support the project and final approval by the Board of Directors.

Coal Marketing and Sales

We sell coal to an established customer base through opportunities as a result of existing business relationships or through formal bidding processes. As is customary in the coal industry, we have entered into long-term coal supply agreements with many of our customers. These arrangements are mutually beneficial to our customers and us in that they provide greater predictability of sales volumes and sales prices. Although many utility customers have appeared to favor a shorter-term contracting strategy, in 2019 approximately 78.5% and 78.3% of our sales tonnage and total coal sales, respectively, were sold under long-term contracts with committed term expirations ranging from 2020 to 2024. As of February 14, 2020, our nominal commitment under contract was approximately 29.3 million tons in 2020, 18.4 million tons in 2021 and 6.7 million tons in 2022. The commitment of coal under contract is an approximate number because a limited number of our contracts contain provisions that could cause the nominal commitment to increase or decrease; however, the overall variance to total committed sales is minimal. The contractual time commitments for customers to nominate future purchase volumes under these contracts are typically sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal commitment can otherwise change because of reopener provisions contained in certain of these long-term contracts.

The provisions of long-term contracts are the results of both bidding procedures and extensive negotiations with each customer. As a result, the provisions of these contracts vary significantly in many respects, including, among other factors, price adjustment features, price and contract reopener terms, permitted sources of supply, force majeure provisions, and coal qualities and quantities. A portion of our long-term contracts are subject to price adjustment provisions, which periodically permit an increase or decrease in the contract price, typically to reflect changes in specified indices or changes in production costs resulting from regulatory changes, or both. These provisions, however, may not assure that the contract price will reflect every change in production or other costs. Failure of the parties to agree on a price pursuant to an adjustment or a reopener provision can, in some instances, lead to early termination of a contract. Some of the long-term contracts also permit the contract to be reopened for renegotiation of terms and conditions other than pricing terms, and where a mutually acceptable agreement on terms and conditions cannot be concluded, either party may have the option to terminate the contract. The long-term contracts typically stipulate procedures for transportation of coal, quality control, sampling, and weighing. Most contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics such as heat, sulfur, ash, moisture, grindability, volatility and other qualities. Failure to meet these specifications can result in economic penalties, rejection or suspension of shipments or termination of the contracts. While most of the contracts specify the approved seams and/or approved locations from which the coal is to be mined, some contracts allow the coal to be sourced from more than one mine or location. Although the volume to be delivered pursuant to a long-term contract is stipulated, the buyers often have the option to vary the volume within specified limits. Coal contracts typically contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events. Force majeure events include, but are not limited to, unexpected significant geological conditions and weather events that may disrupt transportation. Depending on the language of the contract, some contracts may terminate upon an event of force majeure that extends for a certain period.

The international coal market has been a substantial part of our business with indirect sales to end users in Europe, Africa, Asia, North America and South America. Our sales into the international coal market are considered exports and are made through brokered transactions. During the years ended December 31, 2019, 2018, and 2017, export tons represented approximately 17.9%, 27.8%, and 17.4% of tons sold, respectively. We use the end usage point as the basis for attributing tons to individual countries. Because title to our export shipments typically transfers to our brokerage customers at a point that does not necessarily reflect the end usage point, we attribute export tons to the country with the end usage point, if known.

Reliance on Major Customers

During 2019, we derived more than 10.0% of our total revenues from each of two customers, Louisville Gas and Electric Company and FirstEnergy Corp. We did not derive 10.0% or more of our total revenues from any other individual customer during 2019. For more information about these two customers, please read "Item 8. Financial Statement and Supplemental Data—Note 22 – Concentration of Credit Risk and Major Customers."

Coal Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal price, coal quality (including sulfur and heat content), reliability and diversity of supply, and transportation costs from the mine to the customer. We are currently the second largest coal producer in the eastern United States. Our principal competitors include CONSOL Energy, Inc., Contura Energy, Inc., Foresight Energy LP, Murray Energy, Inc., and Peabody Energy Corporation. While a number of our competitors have been involved in reorganization in bankruptcy, these events have not resulted in a material diminution in available coal supply and there remains significant competition for ongoing coal sales. We also compete directly with a number of smaller producers in the Illinois Basin and Appalachian regions.

In addition, we compete with companies that produce coal from one or more foreign countries. We export a significant portion of our coal into the international coal markets and historically the prices we obtain for our export coal have been influenced by a number of factors, such as global economic conditions, weather patterns, and global supply and demand, among others. Potential changes to international trade agreements, trade concessions, or other political and economic arrangements may benefit coal producers operating in countries other than the United States. We may be adversely impacted on the basis of price or other factors by foreign trade policies or other arrangements that benefit competitors. In addition, coal is sold internationally in United States dollars and, as a result, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide our foreign competitors with a competitive advantage. If our competitors' currencies decline against the United States dollar or against foreign purchasers' local currencies, those competitors may be able to offer lower prices for coal to those purchasers. Furthermore, if the currencies of overseas purchasers were to significantly decline in value in comparison to the United States dollar, those purchasers may seek decreased prices for the coal we sell to them. Consequently, currency fluctuations could adversely affect the competitiveness of our coal in international markets, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

The prices we are able to obtain for our domestic sales of coal are primarily linked to coal consumption patterns of domestic electricity generating utilities, which in turn are influenced by economic activity, government regulations, weather, and technological developments, as well as the location, quality, price and availability of competing sources of fuel and alternative energy sources such as natural gas, nuclear energy, petroleum and renewable energy sources for electrical power generation. Costs and other factors, such as safety and environmental considerations, have affected and may continue to affect the overall demand for coal as a fuel. Competition from natural-gas fired plants that are relatively more efficient, less expensive to construct and less difficult to permit than coal-fired plants has displaced and may continue to displace a significant amount of coal-fired electric power generation in the near term, particularly from older, less efficient coal-fired powered generators. Federal and state mandates for increased use of electricity derived from renewable energy sources could affect demand for our coal. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, could make alternative fuel sources more competitive with coal.

For additional information, please see "Item 1A. Risk Factors."

Coal Transportation

Our coal is transported from our mining complexes to our customers by barge, rail, and truck. Depending on the proximity of the customer to the mining complex and the transportation available for delivering coal to that customer, transportation costs can be a substantial part of the total delivered cost of a customer's coal. As a consequence, the availability and cost of transportation constitute important factors in the marketability of coal. We believe our mines are located in favorable geographic locations that minimize transportation costs for our customers, and in many cases we are able to accommodate multiple transportation options. Our customers typically negotiate and pay the transportation costs from the mining complex to the destination, which is the standard practice in the industry. Approximately 47.5% of our 2019 sales volume was initially shipped from the mining complexes by barge, 33.9% was shipped from the mining complexes by rail and 18.6% was shipped from the mining complexes by truck. The practices of, rates set by and capacity availability of, the transportation company serving a particular mine or customer may affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mining complex. With respect to our export volumes from the United States to other countries, we generally sell coal to our customers at an export terminal in the United States and we are responsible for the cost of transporting coal to the export terminals. Our export customers generally negotiate and pay for the ocean vessel transportation.

Mineral Interest Activities

Our mineral interest business includes all activities related to the oil & gas mineral interests held by AR Midland and AllDale I & II and includes Alliance Minerals, LLC's ("Alliance Minerals") equity interests in both AllDale III and Cavalier Minerals. AR Midland acquired its mineral interests in the Wing Acquisition. Our mineral interests are primarily located in three basins, which are also our areas of focus for future development by operators. These include the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) Basins. Our developed and undeveloped net acres standardized to a 1/8th royalty equate to approximately 55,700 net royalty acres, including 3,989 net royalty acres owned through our equity interests in AllDale III.

When our mineral interests are leased, we typically receive an upfront cash payment, known as lease bonus, and we retain a mineral royalty, which entitles us to receive a fixed percentage of the revenue or production from the oil & gas produced from the acreage underlying our interests, free of lease operating expenses and capital costs. A lessee can extend the lease beyond the initial lease term with continuous drilling, production, or other operating activities, or by making an extension payment. When production or drilling ceases, the lease terminates, allowing us to lease the exploration and development rights to another party. As an owner of mineral interests, we incur the initial cost to acquire our interests but thereafter only incur our proportionate share of production and ad valorem taxes. Unlike owners of working interests in oil & gas properties, we are not obligated to fund drilling and completion costs or plugging and abandonment costs associated with oil & gas production.

The following chart summarizes production of our mineral interests for the year ended December 31, 2019:

	Year Ended December 31, 2019
Production:	
Oil (MBbls)	741
Natural gas (MMcf)	3,664
Natural gas liquids (MBbls)	364
BOE (MBbls)	1,716

The following map shows the location of our oil & gas mineral interests:

In 2014, ARLP began to actively invest in oil & gas mineral interests in some of the nation's premier oil-rich basins. Throughout 2019, ARLP has transitioned from a passive investor in mineral interests to an active and material participant in oil & gas minerals.

Permian Basin—Delaware and Midland Basins

The Permian Basin ranges from West Texas into southeastern New Mexico and is currently the most active area for horizontal drilling in the United States. The Permian Basin is further subdivided into the Delaware Basin in the west and the Midland Basin in the east. Based on geologic data and the ongoing development by operators, our mineral interests in the Permian Basin contain multiple producing zones of economic horizontal development including but not limited to the Wolfcamp, Spraberry, and Bone Spring formations. Our recent purchase of acreage located entirely in the Permian Basin through the Wing Acquisition demonstrates our commitment to continued acquisition of mineral interests in the nation's highest growth oil & gas plays.

Anadarko Basin—SCOOP and STACK Plays

The SCOOP play (South Central Oklahoma Oil Province) is located in central Oklahoma in Grady, Garvin, Stephens, and McClain Counties. Based on geologic data and the ongoing development by operators, our mineral interests in the SCOOP play contain multiple producing zones of economic horizontal development including multiple Woodford benches and the Springer Shale. In addition, operators are also currently testing other formations in the area including the Sycamore, Caney, and Osage, which is also referred to as SCORE (Sycamore Caney Osage Resource Expansion). The STACK play (derived from Sooner Trend, Anadarko Basin, Canadian and Kingfisher Counties) is located in central Oklahoma in Kingfisher, Canadian, Caddo, and Blaine Counties. Based on geologic data and the ongoing development by operators, our mineral interests in the STACK play contain multiple producing zones of economic horizontal development including but not limited to the Meramec and Woodford formations.

Williston Basin—Bakken

The Williston Basin stretches from western North Dakota into eastern Montana. Based on geologic data and ongoing development by operators, our mineral interests contain multiple producing zones of economic horizontal development including the Bakken and Three Forks formations.

Other

Our other interests are comprised primarily of mineral interests owned in the Appalachia Basin that stretches throughout most of Ohio, West Virginia, Pennsylvania, and extends into other states. The Appalachia Basin's most active plays in which we have acreage are the Marcellus Shale and Utica plays, which cover most of Pennsylvania, northern West Virginia, and eastern Ohio. In addition to the interests held in the Appalachia Basin, we own a small amount of mineral interests in the Tuscaloosa Marine Shale play in Mississippi. AllDale III also owns mineral interests in the Haynesville Shale formation located in northwest Louisiana.

Minerals Competition

There is intense competition for acquisition opportunities in the oil & gas industry, and we compete with other companies that have greater resources. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to acquire additional mineral interests in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our competitors not only own and acquire mineral interests but also explore for and produce oil & gas and, in some cases, carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. By engaging in such other activities, our competitors may be able to develop or obtain information that is superior to the information that is available to us. In addition, because we have fewer financial and human resources than many companies in the oil & gas industry, we may be at a disadvantage in bidding for oil & gas properties. Further, oil & gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil & gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil & gas.

Minerals - Seasonal Nature of Business

Generally, demand for oil increases during the summer months and decreases during the winter months while demand for natural gas increases during the winter and summer months and decreases during the spring and fall months. Certain buyers of natural gas use natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit drilling and producing activities and other oil & gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for our operators in meeting well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations.

Other Operations

Coal Brokerage

As markets allow, Alliance Coal buys coal from our mining operations and outside producers principally throughout the eastern United States, which we then resell. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal. In 2019, we made outside coal purchases for brokerage activity of 479,764 tons.

Matrix Group

Our subsidiaries, Matrix Design Group, LLC ("Matrix Design") and its subsidiaries Matrix Design International, LLC and Matrix Design Africa (PTY) LTD, and Alliance Design Group, LLC ("Alliance Design") (collectively the Matrix

Design entities and Alliance Design are referred to as the "Matrix Group"), provide a variety of mining technology products and services for our mining operations and certain industrial and mining technology products and services to third parties. Matrix Group's products and services include miner and equipment tracking systems and proximity detection systems. We acquired Matrix Design in September 2006.

Compression Investment

On July 19, 2017, Alliance Minerals purchased $100 million of Series A-1 Preferred Interests from Kodiak, a privately held company providing large-scale, high-utilization gas compression assets to customers operating primarily in the Permian Basin. On February 8, 2019, Kodiak redeemed the preferred interests held by Alliance Minerals for $135.0 million cash that is inclusive of an early redemption premium.

Additional Services

We develop and market additional services in order to establish ourselves as the supplier of choice for our customers. Historically, and in 2019, outside revenues from these services were immaterial.

Environmental, Health, and Safety Regulations

Our coal operations, and those of the operators on the properties in which we hold oil & gas mineral interests, are subject to extensive regulation by federal, state, and local authorities on matters such as:

- employee health and safety;
- permits and other licensing requirements for mining or exploration and production activities;
- air quality standards;
- water quality standards;
- storage of petroleum products and substances that are regarded as hazardous under applicable laws or that, if spilled, could reach waterways or wetlands;
- plant and wildlife protection that could limit or prohibit mining or exploration and production activities;
- restrict the types, quantities and concentration of materials that can be released into the environment in the performance of mining or exploration and production activities;
- initiate investigatory and remedial measures to mitigate pollution from former or current operations, such as restoration of waste ponds, mining areas, drilling pits and plugging of abandoned wells;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining; and
- the effects, if any, that mining has on groundwater quality and availability

Failure to comply with environmental laws and regulations may result in the assessment of administrative, civil and criminal sanctions, including monetary penalties, the imposition of strict, joint and several liability, investigatory and remedial obligations and the issuance of injunctions limiting or prohibiting some or all of the operations on our properties. The regulatory burden on fossil fuel industries increases the cost of doing business and consequently affects profitability. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly obligations could increase our or our mineral interest operators' costs and adversely affect our performance.

In addition, the utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which has adversely affected demand for coal. It is possible that new legislation or regulations may be adopted, or that existing laws or regulations may be differently interpreted or more stringently enforced, any of which could have a significant impact on our mining operations, our customers' ability to use coal, or the value of or amount of royalties received from our mineral interests. For more information, please see risk factors described in "Item 1A. Risk Factors" below.

We are committed to conducting mining operations in compliance with applicable federal, state, and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, particularly the regulatory system of the Mine Safety and Health Administration ("MSHA") where citations can be issued without regard to fault and many of the standards include subjective elements, it is not reasonable to expect any coal mining company to be free of citations. When we receive a citation, we attempt to promptly remediate any identified condition. While we have not quantified all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations has substantially increased the cost of coal mining for domestic coal producers.

Capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value of the estimated cost of asset retirement obligations and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations and mine closing costs are based upon permit requirements and the costs and timing of asset retirement obligations 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 these accruals were insufficient.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. Applications for permits require extensive engineering and data analysis and presentation, and must address a variety of environmental, health, and safety matters associated with a proposed mining operation. These matters include the manner and sequencing of coal extraction, the storage, use, and disposal of waste and other substances and impacts on the environment, the construction of water containment areas, and reclamation of the area after coal extraction. Meeting all requirements imposed by any of these authorities may be costly and time consuming, and may delay or prevent commencement or continuation of mining operations.

The permitting process for certain mining operations can extend over several years and can be subject to administrative and judicial challenge, including by the public. Some required mining permits are becoming increasingly difficult to obtain in a timely manner, or at all. We cannot assure you that we will not experience difficulty or delays in obtaining mining permits in the future or that a current permit will not be revoked.

We are required to post bonds to secure performance under our permits. Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws and regulations described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws and regulations. Regulations also 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 that have outstanding environmental violations. Although, like other coal companies, we have been cited for violations in the ordinary course of our 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.

Mine Health and Safety Laws

The operation of our mines is subject to the Federal Mine Safety and Health Act of 1977 ("FMSHA"), and regulations adopted pursuant thereto. FMSHA imposes extensive and detailed 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 numerous other matters. MSHA monitors and rigorously enforces compliance with these federal laws and regulations. In addition, most of the states where we operate have state programs for mine safety and health regulation and enforcement. Federal and state safety and health regulations affecting the coal mining industry are perhaps the most comprehensive and rigorous system in the United States for protection of employee safety and have a significant effect on our operating costs. Although many of the requirements primarily impact underground mining, our competitors in all of the areas in which we operate are subject to the same laws and regulations.

FMSHA has been construed as authorizing MSHA to issue citations and orders pursuant to the legal doctrine of strict liability, or liability without fault, and FMSHA requires imposition of a civil penalty for each cited violation. Negligence and gravity assessments, and other factors can result in the issuance of various types of orders, including orders requiring withdrawal from the mine or the affected area, and some orders can also result in the imposition of civil penalties. FMSHA also contains criminal liability provisions. For example, criminal liability may be imposed upon corporate operators who knowingly and willfully authorize, order, or carry out violations of the FMSHA, or its mandatory health and safety standards.

The Federal Mine Improvement and New Emergency Response Act of 2006 ("MINER Act") significantly amended the FMSHA, 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, MSHA has 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 belts, fire prevention and detection, and use of air from the belt entry; and
- post-accident two-way communications and electronic tracking systems.

MSHA continues to interpret and implement various provisions of the MINER Act, along with introducing new proposed regulations and standards.

In 2014, MSHA began implementation of a finalized new regulation titled "Lowering Miner's Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors." The final rule implemented a reduction in the allowable respirable coal mine dust exposure limits, requires the use of sampling data taken from a single sample rather than an average of samples, and increases oversight by MSHA regarding coal mine dust and ventilation issues at each mine, including the approval process for ventilation plans at each mine, all of which increase mining costs. The second phase of the rule began in February 2016 and requires additional sampling for designated and other occupations using the new continuous personal dust monitor technology, which provides real time dust exposure information to the miner. Phase three of the rule began in August 2016, and resulted in lowering the current respirable dust level of 2.0 milligrams per cubic meter to 1.5 milligrams per cubic meter of air. Compliance with these rules can result in increased costs on our operations, including, but not limited to, the purchasing of new equipment and the hiring of additional personnel to assist with monitoring, reporting, and recordkeeping obligations. MSHA has published a request for information regarding engineering controls and best practices to lower miners' exposure to respirable coal mine dust, which is currently set to close on July 9, 2022. It is uncertain whether MSHA will present additional proposed rules, or revisions to the final rule, following the closing of the comment period for the current request for information.

Additionally, in July 2014, MSHA proposed a rule addressing the "criteria and procedures for assessment of civil penalties." Public commenters have expressed concern that the proposed rule exceeds MSHA's rulemaking authority and would result in substantially increased civil penalties for regulatory violations cited by MSHA. MSHA last revised the process for proposing civil penalties in 2006 and, as discussed above, civil penalties increased significantly. The notice-and-comment period for this proposed rule closed, and it is uncertain when, or if, MSHA will present a final rule addressing these civil penalties.

In January 2015, MSHA published a final rule requiring mine operators to install proximity detection systems on continuous mining machines, over a staggered time frame ranging from November 2015 through March 2018. The proximity detection systems initiate a warning or shutdown the continuous mining machine depending on the proximity of the machine to a miner. MSHA subsequently proposed a rule requiring mine operators to also install proximity detection systems on other types of underground mobile mining equipment. The comment period for this proposed rule closed on April 10, 2017, and it is uncertain when MSHA will promulgate a final rule addressing the issue of proximity detection systems on underground mobile mining equipment, other than continuous mining machines.

In June 2016, MSHA published a request for information on Exposure of Underground Miners to Diesel Exhaust. Following a comment period that closed in November 2016, MSHA received requests for MSHA and the National Institute for Occupational Safety and Health to hold a Diesel Exhaust Partnership to address the issues covered by MSHA's request for information. The comment period for the request for information is scheduled to close in September 2020. It is uncertain whether MSHA will present a proposed rule pertaining to exposure of underground miners to diesel exhaust, after completing its evaluation of the comments received.

In June 2018, MSHA published a request for information on Safety Improvement Technologies for Mobile Equipment at Surface Mines and for Belt Conveyors at Surface and Underground Mines. The comment period for the request for information has closed. It is uncertain whether MSHA will present a proposed rule pertaining to safety improvement technologies for mobile equipment at surface mines or for belt conveyors at surface and underground mines.

Subsequent to passage of the MINER Act, Illinois, Kentucky, Pennsylvania and West Virginia have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight. Additionally, state administrative agencies can promulgate administrative rules and regulations affecting our operations. Other states may pass similar legislation or administrative regulations in the future.

Some of the costs of complying with existing regulations and implementing new safety and health regulations may be passed on to our customers. Although we have not quantified the full impact, implementing and complying with these new federal and state safety laws and regulations have had, and are expected to continue to have, an adverse impact on our results of operations and financial position.

Black Lung Benefits Act

The Black Lung Benefits Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981 ("BLBA") requires businesses that conduct current mining operations to make payments of black lung benefits to current and former coal miners with black lung disease and to some survivors of a miner who dies from this disease. The BLBA levied a tax on coal sold of $1.10 per ton for underground-mined coal and $0.55 per ton for surface-mined coal, but not to exceed 4.4% of the applicable sales price, in order to compensate miners who are totally disabled due to black lung disease and some survivors of miners who died from this disease, and who were last employed as miners prior to 1970 or subsequently where no responsible coal mine operator has been identified for claims. The coal we sell into international markets is generally not subject to this tax. In addition, the BLBA provides that some claims for which coal operators had previously been responsible are or will become obligations of the government trust funded by the tax. The Revenue Act of 1987 extended the termination date of this tax from January 1, 1996, to the earlier of January 1, 2014, or the date on which the government trust becomes solvent. The Emergency Economic Stabilization Act of 2008 extended these rates through December 31, 2018. On January 1, 2019, the excise tax rates reverted to their original 1977 statutory levels of $0.50 per ton for underground-mined coal and $0.25 per ton for surface mined coal, but not to exceed 2% of the applicable sales price. In December 2019, the excise tax rates were increased to their 2018 levels and that rate increase is set to expire on December 31, 2020.

Workers' Compensation and Black Lung

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. We generally self-insure this potential expense using our actuary estimates of the cost of present and future claims. In addition, coal mining companies are subject to federal legislation and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker's pneumoconiosis, or black lung. We also provide for these claims through self-insurance programs. Our pneumoconiosis benefits liability is calculated using the service cost method based on the actuarial present value of the estimated pneumoconiosis benefits obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents, and discount rates. For more information concerning our requirement to maintain bonds to secure our workers' compensation obligations, see the discussion of surety bonds below under "—*Bonding Requirements.*"

The revised BLBA regulations took effect in January 2001, relaxing the stringent award criteria established under previous regulations and thus potentially allowing new federal claims to be awarded and allowing previously denied claimants to re-file under the revised criteria. These regulations may also increase black lung related medical costs by broadening the scope of conditions for which medical costs are reimbursable and increase legal costs by shifting more of the burden of proof to the employer.

The Patient Protection and Affordable Care Act, enacted in 2010, includes significant changes to the federal black lung program retroactive to 2005, 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 have caused a significant increase in our costs expended in association with the federal black lung program.

Surface Mining Control and Reclamation Act

The Federal Surface Mining Control and Reclamation Act of 1977 ("SMCRA") and similar state statutes establish operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining.

Although we have minimal surface mining activity and no mountaintop removal mining activity, SMCRA nevertheless requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of our mining activities.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. Federal law and some states impose on mine operators the responsibility 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 longwall mining and possibly other mining operations. We believe we are in compliance in all material respects with applicable regulations relating to reclamation.

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 before 1977. The tax for surface-mined and underground-mined coal is $0.28 per ton and $0.12 per ton, respectively. We have accrued the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. Please read "Item 8. Financial Statements and Supplementary Data—Note 18 – Asset Retirement Obligations." In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation or orphaned mine sites and acid mine drainage control on a statewide basis.

Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent contract mine operators and other third parties can be imputed to other companies that are deemed, according to the regulations, to have "owned" or "controlled" the third-party violator. Sanctions against the "owner" or "controller" are quite severe and can include being blocked from receiving new permits and having any permits revoked that were issued after the time of the violations or after the time civil penalties or reclamation fees became due. We are not aware of any currently pending or asserted claims against us relating to the "ownership" or "control" theories discussed above. However, we cannot assure you that such claims will not be asserted in the future.

In April 2015, the United States Environmental Protection Agency ("EPA") finalized rules on coal combustion residuals ("CCRs"); however, the final rule does not address the placement of CCRs in minefills or non-minefill uses of CCRs at coal mine sites. OSM has announced their intention to release a proposed rule to regulate placement and use of CCRs at coal mine sites, but, to date, no further action has been taken. These actions by OSM, potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities, and additional enforcement actions.

Bonding Requirements

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation, to pay certain black lung claims, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors to secure new surety bonds without posting collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. 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 federal and state laws would have a material adverse effect on our ability to produce coal, which could affect our profitability and cash flow. For additional information, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Off-Balance Sheet Arrangements*."

Air Emissions

The CAA and similar state and local laws and regulations regulate emissions into the air and affect coal mining, as well as oil & gas, operations. The CAA imposes permitting requirements and, in some cases, requirements to install certain emissions control equipment, achieve certain emissions standards, or implement certain work practices on sources that emit various 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 coal-burning facilities. There have been a series of federal rulemakings focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and any additional measures required under applicable federal and state 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 ("SIPs"), could make fossil fuels a less attractive fuel alternative in the planning and building of power plants in the future. A significant reduction in fossil fuels' share of power generating capacity could have a material adverse effect on our business, financial condition and results of operations. Since 2010, utilities have completed or formally announced the retirement or conversion of almost 700 coal-fired electric generating units through 2030 in the United States.

In addition to the greenhouse gas ("GHG") issues discussed below, the air emissions programs that may affect our operations or the operations of those on the properties in which we hold mineral interests, directly or indirectly, 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. In 2019, we sold 78.8% of our total tons to electric utilities in the United States, of which 100% was sold to utility plants with installed pollution control devices. These requirements would not be supplanted by a replacement rule for the Clean Air Interstate Rule ("CAIR"), discussed below.

- The CAIR calls for power plants in 28 states and Washington, D.C. to reduce emission levels of sulfur dioxide and nitrogen oxide pursuant to a cap-and-trade program similar to the system in effect for acid rain. In June 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR"), a replacement rule for CAIR, which would have required 28 states in the Midwest and eastern seaboard to reduce power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. CSAPR has become increasingly irrelevant with continuing coal plant retirements making the nitrogen oxide ozone budget less stringent and lowering emission allowance prices to levels closer to average operating cost for many of our customers. The full impact of CSAPR are unknown at the present time due to the implementation of Mercury and Air Toxic Standards ("MATS"), discussed below, and the impact of the continuing coal plant retirements.

- In February 2012, the EPA adopted the MATS, which regulates the emission of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal and oil-fired power plants. In March 2013, the EPA finalized a reconsideration of the MATS rule as it pertains to new power plants, principally adjusting emissions limits to levels attainable by existing control technologies. In subsequent litigation, the United States Supreme Court struck down the MATS rule based on the EPA's failure to take costs into consideration. The D.C. Circuit Court allowed the current rule to stay in place until the EPA issued a new finding. In April 2016, the EPA issued a final supplemental finding upholding the rule and concluding that a cost analysis supports the MATS rule. In April 2017, the D.C Circuit Court of Appeals granted the EPA's request to cancel oral arguments and ordered the case held in abeyance for an EPA review of the supplemental finding. In December 2018, the EPA issued a proposed Supplemental Cost Finding, as well as the CAA required "risk and technology review." Many electric generators have already announced retirements due to the MATS rule. Although various issues surrounding the MATS rule remain subject to litigation in the D.C. Circuit, the MATS rule has forced generators to make capital investments to retrofit power plants and could lead to additional premature retirements of older coal-fired generating units. The announced and possible additional retirements are likely to reduce the demand for coal. Apart from MATS, several states have enacted or proposed regulations requiring reductions in mercury emissions from coal-fired power plants, and federal legislation to reduce mercury emissions from power plants has been proposed. Regulation of mercury emissions by the EPA, states, or Congress may decrease the future demand for coal. We continue to evaluate the possible scenarios associated with CSAPR Update and MATS and the effects they may have on our business and our results of operations, financial condition or cash flows.

- The EPA is required by the CAA to periodically re-evaluate the available health effects information to determine whether the National Ambient Air Quality Standards ("NAAQS") should be revised. Pursuant to this process, the EPA has adopted more stringent NAAQS for fine particulate matter ("PM"), ozone, nitrogen oxide, 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 and other states will be required to develop new SIPs for areas that were previously in "attainment" but do not attain the new standards. In addition, under the revised ozone NAAQS, significant additional emissions control expenditures may be required at coal-fired power plants. Initial non-attainment determinations related to the revised sulfur dioxide standard became effective in October 2013. In addition, in January 2013, the EPA updated the NAAQS for fine particulate matter emitted by a wide variety of sources including power plants, industrial facilities, and gasoline and diesel engines, tightening the annual PM 2.5 standard to 12 micrograms per cubic meter. The revised standard became effective in March 2013. In November 2013, the EPA proposed a rule to clarify PM 2.5 implementation requirements to the states for current 1997 and 2006 non-attainment areas. In July 2016, the EPA issued a final rule for states to use in creating their plans to address particulate matter. In October 2015, the EPA published a final rule that reduced the ozone NAAQS from 75 to 70 ppb and completed attainment/non-attainment designations in July 2018. In March 2019, the EPA published a final rule that retained the current primary NAAQS for sulfur oxide. New standards may impose additional emissions control requirements on new and expanded coal-fired power plants and industrial boilers. Because coal mining operations and coal-fired electric generating facilities emit particulate matter and sulfur dioxide, our mining operations and our customers could be affected when the new standards are implemented by the applicable states, and developments might indirectly reduce the demand for coal. Separately, implementation of new standards by states has a potential to delay or otherwise impact oil & gas production activities, which could reduce the profitability of our mineral interests.

- The EPA's regional haze program is designed to protect and improve visibility at and around national parks, national wilderness areas, and international parks. Under the program, states are required to develop SIPs to improve visibility. Typically, these plans call for reductions in sulfur dioxide and nitrogen oxide emissions from coal-fueled electric plants. In prior cases, the EPA has decided to negate the SIPs and impose stringent requirements through FIPs. The regional haze program, including particularly the EPA's FIPs, and any future regulations may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations. In September 2018, the EPA issued a memorandum that detailed plans to assist states as they develop their SIPs.

- The EPA's new source review ("NSR") program under the CAA in certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly increase emissions, to install more stringent air emissions control equipment. 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 NSR program. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the program. Several of these lawsuits have settled, but others remain pending. In addition, there are proposals to modify the NSR program as a part of the Affordable Clean Energy ("ACE") rule, which is subject to current pending litigation as discussed below. A final rule on NSR reforms is expected in March 2020. Depending on the ultimate resolution of these cases, demand for coal could be affected.

- The EPA’s New Source Performance Standards ("NSPS") under the CAA require the reduction of volatile organic compounds and methane emissions from certain stimulated oil & gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions. " These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. Subsequently, the Trump Administration has made several attempts to modify CAA regulations related to methane emissions from oil & gas sources. These attempts are subject to ongoing litigation. Most recently, in August 2019, the EPA proposed amendments to the existing methane requirements that, among other things, could rescind methane-specific requirements applicable to upstream facilities but retain requirements for volatile organic compound emissions. Legal challenges to any final rule rescinding federal methane requirements is expected. Oil & gas production on the properties in which we hold mineral interests could be adversely affected to the extent any final rule imposes increased operating costs on the oil & gas industry.

GHG Emissions

Combustion of fossil fuels, such as the coal we produce and the oil & gas produced from our mineral interests, results in the emission of GHGs, such as carbon dioxide and methane. Combustion of fuel for mining equipment used in coal production also emits GHGs. Future regulation of GHG emissions in the United States could occur pursuant to future United States treaty commitments, new domestic legislation or regulation by the EPA. Former President Obama expressed support for a mandatory cap and trade program to restrict or regulate emissions of GHGs and Congress has considered various proposals to reduce GHG emissions, and it is possible federal legislation could be adopted in the future. Internationally, there is an international climate agreement (the "Paris Agreement") that does not create any binding obligations for nations to limit their GHG emissions but includes pledges to voluntarily limit or reduce future emissions. These commitments could further reduce demand and prices for fossil fuels. In November 2019, the United States announced its withdrawal from such agreement, effective November 4, 2020. However, the United States may subsequently decide to rejoin the Paris Agreement or another agreement at some point in the future. Moreover, many states, regions, and governmental bodies have adopted GHG initiatives and have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities, including coal-fired electric generating facilities. Others have announced their intent to increase the use of renewable energy sources, displacing coal and other fossil fuels. Depending on the particular regulatory program that may be enacted, at either the federal or state level, the demand for coal could be negatively impacted, which would have an adverse effect on our operations.

Even in the absence of new federal legislation, the EPA has begun to regulate GHG emissions under the CAA based on the United States Supreme Court's 2007 decision that the EPA has authority to regulate GHG emissions. Although the United States Supreme Court's holding did not expressly involve the EPA's authority to regulate GHG emissions from stationary sources, such as coal-fueled power plants, the EPA has determined on its own that it has the authority to regulate GHG emissions from power plants and issued a final rule which found that GHG emissions, including carbon dioxide and methane, endanger both the public health and welfare.

On September 20, 2013, the EPA issued NSPS for carbon dioxide emissions from new fossil fuel-fired power plants. This rule was finalized in 2015 and was immediately challenged by multiple parties. In August 2017, this rule was stayed by a federal appeals court to allow the Trump administration's EPA to review the NSPS rule. It is likely than any repeal or revisions to the NSPS will be subject to legal challenges as well. Future implementation of the NSPS is uncertain at this time.

In August 2015, the EPA issued its final Clean Power Plan ("CPP") rules that establish carbon pollution standards for power plants, called CO2 emission performance rates. Judicial challenges led the United States Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the United States Court of Appeals for the District of Columbia ("Circuit Court") even issued a decision. Additionally, in October 2017 the 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. The EPA subsequently proposed the ACE rule to replace the CPP with a rule that utilizes heat rate improvement measures as the "best system of emission reduction". The ACE rule adopts new implementing regulations under the CAA to clarify the roles of the EPA and the states, including an extension of the deadline for state plans and EPA approvals; and, the rule revises the NSR permitting program to provide EGUs the opportunity to make efficiency improvements without triggering NSR permit requirements. In June 2019, the EPA published the final repeal of the Clean Power Plan and promulgation of the ACE rule. The EPA's attempts to replace the CPP with the ACE rule are currently subject to litigation, and we cannot predict the final outcome.

Notwithstanding the ACE rule, these requirements have led to premature retirements and could lead to additional premature retirements of coal-fired generating units and reduce the demand for coal. Congress has not currently adopted legislation to restrict carbon dioxide emissions from existing power plants and it is unclear whether the EPA has the legal authority to regulate carbon dioxide emissions from existing and modified power plants as proposed in the NSPS and CPP. Substantial limitations on GHG emissions could adversely affect demand for the coal we produce or the oil & gas produced from our mineral interests.

There have been numerous protests of and challenges to the permitting of new fossil fuel infrastructure, including power plants and pipelines, by environmental organizations and state regulators for concerns related to GHG emissions. For instance, various state regulatory authorities have 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-fueled power plants without limits on

GHG emissions have been appealed to the EPA's Environmental Appeals Board. In addition, over thirty states have currently adopted "renewable energy standards" or "renewable portfolio standards," which encourage or require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. Several states have announced their intent to have renewable energy comprise 100% of their electric generation portfolio. 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, or those of our mineral interest producers, they may reduce the demand for fossil fuel energy, and may affect long-term demand for our coal and the oil & gas producers from the properties in which we hold mineral interests. Finally, while the United States Supreme Court has held that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, the Court did not decide whether similar claims can be brought under state common law. As a result, despite this favorable ruling, tort-type liabilities remain a concern.

In addition, environmental advocacy groups have filed a variety of judicial challenges claiming that the environmental analyses conducted by federal agencies before granting permits and other approvals necessary for certain coal activities do not satisfy the requirements of the National Environmental Policy Act ("NEPA"). These groups assert that the environmental analyses in question do not adequately consider the climate change impacts of these particular projects. In January 2020, the CEQ issued a proposed revision to NEPA regulations that seeks to clarify the extent to which direct, indirect, and cumulative environmental impacts from a proposed project, including GHG emissions, should be examined under NEPA; however, the final form or impact of any such revisions is uncertain at this time.

Many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHG 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 statutes and/or regulations a carbon dioxide trading program. Auctions for carbon dioxide allowances under the program began in September 2008. Since its inception, several additional northeastern states and Canadian provinces have joined RGGI as participants or observers. In 2019, New Jersey and Pennsylvania each announced they were joining RGGI.

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 GHG 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, as of 2020, only California and the Canadian provinces of British Columbia, Novia Scotia, and Quebec. Nevertheless, it is likely that these regional efforts will continue based on current trends and concerns related to the reduction of GHG emissions.

It is possible that future international, federal and state initiatives to control GHG emissions could result in increased costs associated with fossil fuel production and consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for fossil fuel consumption could result in some customers switching to alternative sources of fuel, or otherwise adversely affect our operations and demand for our products, or those of the operators of our mineral interests, which could have a material adverse effect on our business, financial condition, and results of operations Finally, activists may try to hamper fossil fuel companies by other means, including pressuring financing and other institutions into restricting access to capital, bonding and insurance, as well as pursuing tort litigation for various alleged climate-related impacts.

Water Discharge

The Federal Clean Water Act ("CWA") and similar state and local laws and regulations regulate discharges into certain waters, primarily through permitting. Section 404 of the CWA imposes permitting and mitigation requirements associated with the dredging and filling of certain wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact such wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary permits required under CWA Section 404 as it has traditionally been interpreted by the responsible agencies. However, mitigation requirements under existing and possible future "fill" permits may vary considerably. For that reason, the setting of post-mine asset retirement obligation accruals for such mitigation projects is difficult to ascertain with certainty and may increase in the future. For more information about asset retirement obligations, please read "Item 8. Financial Statements and Supplementary Data—Note 18 - Asset Retirement Obligations." Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of such permitting requirements.

In order for us or the operators of the properties in which we hold oil & gas mineral interests to conduct certain activities, an operator may need to obtain a permit for the discharge of fill material from the United States Army Corps of Engineers ("Corps of Engineers") and/or a discharge permit from the state regulatory authority under the state counterpart to the CWA. Our coal mining operations typically require Section 404 permits to authorize activities such as the creation of slurry ponds and stream impoundments. The CWA authorizes the EPA to review Section 404 permits issued by the Corps of Engineers, and in 2009, the EPA began reviewing Section 404 permits issued by the Corps of Engineers for 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.

The EPA also has statutory "veto" power over a 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." In January 2011, the EPA exercised its veto power to withdraw or restrict the use of a previously issued permit for Spruce No. 1 Surface Mine in West Virginia, which is one of the largest surface mining operations ever authorized in Appalachia. This action was the first time that such power was exercised with regard to a previously permitted coal mining project. A challenge to the EPA's exercise of this authority was made in the United States District Court for the District of Columbia and in March 2012, that court ruled that the EPA lacked the statutory authority to invalidate an already issued Section 404 permit retroactively. In April 2013, the D.C. Circuit Court of Appeals reversed this decision and authorized the EPA to retroactively veto portions of a Section 404 permit. The United States Supreme Court denied a request to review this decision. Any future use of the EPA's Section 404 "veto" power could create uncertainly with regard to our continued use of current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting our coal revenues. In addition, the EPA initiated a preemptive veto prior to the filing of any actual permit application for a copper and gold mine based on fictitious mine scenario. The implications of this decision could allow the EPA to bypass the state permitting process and engage in watershed and land use planning. In June 2018, the EPA Administrator issued a memorandum directing the EPA's Office of Water to promulgate draft regulations eliminating the use of the EPA's Section 404 authority before a Section 404 permit application has been filed, or after a permit has been issued. To date, the EPA has not issued a proposed rule.

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 antidegradation review before approving discharge permits. The adoption of new TMDL-related allocations or any changes to antidegradation policies for streams near our coal mines could require more costly water treatment and could adversely affect our coal production.

Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the CWA. A 2015 rulemaking by the EPA to revise the standard was quickly challenged and nationwide implementation was blocked by a federal appeals court. Should the 2015 rule take effect, or should a different rule expanding the definition of what constitutes a water of the United States be promulgated as a result of the EPA and the Corps of Engineers' rulemaking process, we could face increased costs and delays due to additional permitting and regulatory requirements and possible challenges to permitting decisions. In December 2018, the EPA and the Corps of Engineers issued a proposed rule to "determine the scope of 'waters of the United States' "subject to federal jurisdiction. This proposal would lessen the number of waterbodies subject to the CWA as compared to the 2015 Rule. In January 2020, the EPA finalized its rule regarding the scope of "Waters of the United States." Litigation surrounding these developments is ongoing and we cannot predict the outcome at this time.

Hazardous Substances and Wastes

The Federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), otherwise 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 the release of hazardous substances may be subject to joint and several liability under CERCLA for the costs of cleaning up releases of hazardous substances and natural resource damages. Some products used in coal mining operations generate waste containing hazardous substances. We are currently unaware 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 analogous state laws impose requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-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. Similarly, most wastes associated with the exploration, development, and production of oil & gas are exempt from regulation as hazardous wastes under RCRA, though these wastes typically constitute “solid wastes” that are subject to less stringent non-hazardous waste requirements. However, it is possible that RCRA could be amended or the EPA or state environmental agencies could adopt policies to require such wastes to become subject to more stringent storage, handling, treatment, or disposal requirements, which could impose significant additional costs on the operators of the properties in which we own oil & gas mineral interests. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous substances. 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.

RCRA impacts the coal industry in particular because it regulates the disposal of certain coal combustion by-products ("CCB"). On April 17, 2015, the EPA finalized regulations under RCRA for the disposal of CCB. Under the finalized regulations, CCB is regulated as "non-hazardous" waste and avoids the stricter, more costly, regulations under RCRA's "hazardous" waste rules. While classification of CCB as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our customers' operating costs and potentially reduce their ability to purchase coal.

On November 3, 2015, the EPA published the final rule Effluent Limitations Guidelines and Standards ("ELG"), revising the regulations for the Steam Electric Power Generating category which became effective on January 4, 2016. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. The combined effect of the CCB and ELG regulations has forced power generating companies to close existing ash ponds and will likely force the closure of certain older existing coal burning power plants that cannot comply with the new standards. In November 2019, the EPA proposed revisions to the 2015 ELG rule and announced proposed changes to regulations for the disposal of coal ash in order to reduce compliance costs. It is unclear what impact these regulations will have on the market for our products.

Endangered Species Act

The federal Endangered Species Act ("ESA") and counterpart state legislation protect species threatened with possible extinction. The United States Fish and Wildlife Service (the "USFWS") works closely with the OSM and state regulatory agencies to ensure that species subject to the ESA are protected from potential impacts from mining-related and oil & gas exploration and production activities. If the USFWS were to designate species indigenous to the areas in which we operate as threatened or endangered, or to redesignate a species from threatened to endangered, we or the operators of the properties in which we hold oil & gas mineral interests could be subject to additional regulatory and permitting requirements, which in turn could increase operating costs or adversely affect our revenues.

Other Environmental, Health and Safety Regulations

In addition to the laws and regulations described above, we are subject to regulations regarding underground and above ground storage tanks in which we may store petroleum or other substances. Some monitoring equipment that we use is subject to licensing under the Federal Atomic Energy Act. Water supply wells located on our properties are subject to federal, state, and local regulation. In addition, our use of explosives is subject to the Federal Safe Explosives Act. We are also required to comply with the Federal 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 regulations should not have a material adverse effect on our business, financial condition or results of operations.

Employees

To conduct our operations, as of December 31, 2019, we employed 3,602 full-time employees, including 3,164 employees involved in active mining operations, 247 employees in other operations, and 191 corporate employees. Our work force is entirely union-free.

ITEM 1A. RISK FACTORS

Risks Inherent in an Investment in Us

Cash distributions are not guaranteed and may fluctuate with our performance and other external factors.

The amount of cash we can distribute to holders of our common units or other partnership securities each quarter principally depends on 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 and oil & gas produced from our properties;
- the prices at which our coal and oil & gas are sold, which are affected by the supply of and demand for domestic and foreign coal and oil & gas;
- the level of our operating costs;
- weather conditions and patterns;
- the proximity to and capacity of transportation facilities;
- domestic and foreign governmental regulations and taxes;
- regulatory, administrative, and judicial decisions;
- competition and access to capital within our currently targeted industries;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption; and
- prevailing economic conditions.

In addition, the actual amount of cash available for distribution will depend on other factors, including:

- the level of our capital expenditures;
- the cost of acquisitions and investments, including unit repurchases;
- our debt service requirements and restrictions on distributions contained in our current or future debt agreements;
- fluctuations in our working capital needs;
- the amount of revenues we generate from our oil & gas mineral interests;
- unavailability of financing resulting in unanticipated liquidity constraints;
- our ability to borrow under our credit agreement to make distributions to our unitholders; and
- the amount, if any, of cash reserves established by our general partner, in its discretion, for the proper conduct of our business.

Because of these and other factors, we may not have sufficient available cash to pay a specific level of cash distributions to our unitholders. Furthermore, the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowing, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record net losses and may be unable to make cash distributions during periods when we record net income. Please read "—Risks Related to our Business" for a discussion of further risks affecting our ability to generate available cash and "Item 8. Financial Statements and Supplementary Data—Note 11 – Variable Interest Entities" for further discussion of restrictions on the cash available for distribution.

We may issue an unlimited number of limited partner interests, on terms and conditions established by our general partner, without the consent of our unitholders, which will dilute your ownership interest in us and may increase the risk that we will not have sufficient available cash to maintain or increase our per unit distribution level.

The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' 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;
- the ratio of taxable income to distributions may increase; and
- the market price of our common units may decline.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public markets, including sales by our existing unitholders.

The sale or disposition of a substantial number of our common units by our existing unitholders in the public markets 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. We do not know whether any such sales would be made in the public market or in private placements, nor do we know what impact such potential or actual sales would have on our unit price in the future.

An increase in interest rates may cause the market price of our common units to decline.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

The credit and risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and risk profile of our general partner or its owners may be factors in credit evaluations of us as a master limited partnership. This is because our general partner can exercise significant influence or control over our business activities, including our cash distribution policy, acquisition strategy, and business risk profile

Our unitholders do not elect our general partner or vote on our general partner's officers or directors.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner and will have no right to elect our general partner on an annual or other continuing basis.

In addition, if our unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Our general partner may not be removed except upon the vote of the holders of at least 66.7% of our outstanding units.

Our unitholders' voting rights are also restricted by a provision in our partnership agreement that provides that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter.

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 in us to a third party in a merger or in a sale of its equity securities without the consent of our unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the members of our general partner to sell or transfer all or part of their ownership interest in our general partner to a third party. The new owner or owners of our general partner would then be in a position to replace the directors and officers of our general partner and control the decisions made and actions taken by the Board of Directors and officers.

Unitholders may be required to sell their units to our general partner at an undesirable time or price.

If at any time less than 20.0% of our outstanding common units are held by persons other than our general partner and its affiliates, our general partner will have the right to acquire all, but not less than all, of those units at a price no less than their then-current market price. As a consequence, a unitholder may be required to sell his common units at an undesirable time or price. Our general partner may assign this purchase right to any of its affiliates or to us.

Cost reimbursements due to our general partner may be substantial and may reduce our ability to pay distributions to unitholders.

Prior to making any distributions to our unitholders, we will reimburse our general partner and its affiliates for all expenses they have incurred on our behalf. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to the unitholders. Our general partner has sole discretion to determine the amount of these expenses and fees. For additional information, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Related-Party Transactions—*Administrative Services*," and "Item 8. Financial Statements and Supplementary Data—Note 20 – Related-Party Transactions."

We depend on the leadership and involvement of Joseph W. Craft III and other key personnel for the success of our business.

We depend on the leadership and involvement of Mr. Craft, the Chairman, President and CEO of our general partner. Mr. Craft has been integral to our success, due in part to his ability to identify and develop internal growth projects and accretive acquisitions, make strategic decisions, and attract and retain key personnel. The loss of his leadership and involvement or the services of any members of our senior management team could have a material adverse effect on our business, financial condition, and results of operations.

Your liability as a limited partner may not be limited, and our unitholders may have to repay distributions or make additional contributions to us under certain circumstances.

As a limited partner in a partnership organized under Delaware law, you could be held liable for our obligations to the same extent as a general partner if you participate in the "control" of our business. Our general partner generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. Additionally, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully distributed to them. Under Delaware law, 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, partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Our partnership agreement limits our general partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates and which reduce the obligations to which our general partner would otherwise be held by state-law fiduciary duty standards. The following is a summary of the material restrictions contained in our partnership agreement on the fiduciary duties owed by our general partner to the limited partners. Our partnership agreement:

- permits our general partner to make a number of decisions in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our general partner is entitled to make other decisions in its "reasonable discretion";
- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the interests of all parties involved, including its own. Unless our general partner has acted in bad faith, the action taken by our general partner shall not constitute a breach of its fiduciary duty; and
- provides that our general partner and our officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partner and those other persons acted in good faith.

In becoming a limited partner of our partnership, a common unitholder is bound by the provisions in the partnership agreement, including the provisions discussed above.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of AGP. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our unitholders' best interests. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations, and financial condition.

Our general partner's discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from available cash reserves that in its reasonable discretion are necessary for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to unitholders.

Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor their own interests to the detriment of our unitholders.

Conflicts of interest could arise in the future as a result of relationships between our general partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates over the interests of our unitholders. The nature of these conflicts includes the following considerations:

- Remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty are limited. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law.
- Our general partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders.
- Our general partner's affiliates are not prohibited from engaging in other businesses or activities, including those in direct competition with us, except as provided in the omnibus agreement (please see "Item 13. Certain Relationships and Related Transactions, and Director Independence—Omnibus Agreement").
- Our general partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings, and reserves, each of which can affect the amount of cash that is distributed to unitholders.
- Our general partner determines whether to issue additional units or other equity securities in us.
- Our general partner determines which costs are reimbursable by us.
- Our general partner controls the enforcement of obligations owed to us by it.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

- Our general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or from entering into additional contractual arrangements with any of these entities on our behalf.
- In some instances, our general partner may borrow funds in order to permit the payment of distributions.

Risks Related to our Business

Global economic conditions or economic conditions in any of the industries in which our customers operate as well as sustained uncertainty in financial markets may have material adverse impacts on our business and financial condition that we currently cannot predict.

Weakness in global economic conditions or economic conditions in any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- the demand for electricity in the United States and globally may decline if economic conditions deteriorate, which may negatively impact the revenues, margins, and profitability of our business;
- any inability of our customers to raise capital could adversely affect their ability to honor their obligations to us; and
- our future ability to access the capital markets may be restricted as a result of future economic conditions, which could materially impact our ability to grow our business, including development of our coal reserves.

Growing our business could require significant amounts of financing that may not be available to us on acceptable terms, or at all.

We plan to fund capital expenditures for our growth initiatives with existing cash balances, future cash flows from operations, borrowings under revolving credit and securitization facilities, and cash provided from the issuance of debt or equity. At times, weakness in the energy sector in general and coal in particular has significantly impacted access to the debt and equity capital markets. Accordingly, our funding plans may be negatively impacted by constraints in the capital markets as well as numerous other factors, including higher than anticipated capital expenditures or lower than expected cash flow from operations. In addition, we may be unable to refinance our current debt obligations when they expire or obtain adequate funding prior to expiry because our lending counterparties may be unwilling or unable to meet our funding needs. Furthermore, additional growth projects and expansion opportunities may develop in the future that could also require significant amounts of financing that may not be available to us on acceptable terms or in the amounts we expect, or at all.

Various factors could adversely impact the debt and equity capital markets as well as our credit ratings or our ability to remain in compliance with the financial covenants under our then current debt agreements, which in turn could have a material adverse effect on our financial condition, results of operations, and cash flows. If we are unable to finance our growth initiatives as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our plans.

Expansions and acquisitions involve a number of risks, any of which could cause us not to realize the anticipated benefits.

If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Expansion and acquisition transactions involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental or mine safety liabilities) of, expansion and acquisition opportunities;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion or an acquisition;
- problems that could arise from the integration of the new operations; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion or acquisition opportunity.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from an expansion or acquisition. Any expansion or acquisition opportunities we pursue could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity capital or both. In addition, future expansions or acquisitions could result in us assuming more long-term liabilities relative to the value of the acquired assets than we have assumed in our previous expansions and/or acquisitions.

Our indebtedness may limit our ability to borrow additional funds, make distributions to unitholders, or capitalize on business opportunities.

We have long-term indebtedness of $789.3 million as of December 31, 2019. Our leverage may:

- adversely affect our ability to finance future operations and capital needs;
- limit our ability to pursue acquisitions and other business opportunities;
- make our results of operations more susceptible to adverse economic or operating conditions; and
- make it more difficult to self-insure for our workers' compensation obligations.

In addition, we have unused borrowing capacity under our revolving credit facility. Future borrowings, under our credit facilities or otherwise, could result in an increase in our leverage.

Our payments of principal and interest on any indebtedness will reduce the cash available for distribution on our units. We will be prohibited from making cash distributions:

- during an event of default under any of our indebtedness; or
- if after such distribution, we fail to meet a coverage test based on the ratio of our consolidated cash flow to our consolidated fixed charges.

Various limitations in our debt agreements may reduce our ability to incur additional indebtedness, to engage in some transactions, and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions. Please see "Item 8. Financial Statements and Supplementary Data – Note 7 – Long-Term Debt" for further discussion.

We and our subsidiaries are subject to various legal proceedings, which may have a material adverse effect on our business.

We are party to a number of legal proceedings incident to our normal business activities. There is the potential that an individual matter or the aggregation of multiple matters could have an adverse effect on our cash flows, results of operations or financial position. Please see "Item 3. Legal Proceedings" and "Item 8. Financial Statements and Supplementary Data—Note 21 – Commitments and Contingencies" for further discussion.

We, our customers, or the operators of our oil & gas mineral interests could be subject to tort claims based on the alleged effects of climate change.

Increasing attention to climate change risk has also resulted in a recent trend of governmental investigations and private litigation by state and local governmental agencies as well as private plaintiffs in an effort to hold energy companies accountable for the alleged effects of climate change. Other public nuisance lawsuits have been brought in the past against power, coal, and oil & gas companies alleging that their operations are contributing to climate change. The plaintiffs in these suits sought various remedies, including punitive and compensatory damages and injunctive relief. While the United States Supreme Court held that federal common law provided no basis for public nuisance claims against the defendants in those cases, tort-type liabilities remain a possibility and a source of concern. Government entities in other states (including California and New York) have brought similar claims seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the GHG emissions attributable to those fuels. Those lawsuits allege damages as a result of climate change and the plaintiffs are seeking unspecified damages and abatement under various tort theories.

We have not been made a party to these other suits, but it is possible that we could be included in similar future lawsuits initiated by state and local governments as well as private claimants.

Prices for oil & gas, as well as coal, are volatile and can fluctuate widely based upon a number of factors beyond our control. An extended decline in the prices of such commodities could negatively impact our results of operations.

Our results of operations are primarily dependent upon the prices of oil & gas and coal, as well as our ability to improve productivity and control costs. The prices for oil & gas and coal depend upon factors beyond our control, including:

- overall domestic and global economic conditions;
- the supply of and demand for domestic and foreign coal;
- the supply of and demand for oil & gas;
- weather conditions and patterns that affect demand for coal and oil & gas, or our ability to produce coal or the ability of operators to produce oil & gas from our mineral interests;
- the proximity to and capacity of transportation facilities;
- competition from other coal suppliers;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption, including the impact of technological advances on energy consumption;
- international developments impacting supply of coal;
- international developments impacting supply of oil & gas; and
- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and regulations affecting the coal mining industry and coal-fired power plants, and delays in the receipt of, failure to receive, failure to maintain or revocation of necessary governmental permits, as well as regulations affecting the oil & gas extraction industry.

Any adverse change in these factors could result in weaker demand and lower prices for our products. A substantial or extended decline in coal prices could materially and adversely affect us by decreasing our revenues to the extent we are not protected by the terms of existing coal supply agreements.

Competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry has put downward pressure on coal prices. In addition, foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We compete with other coal producers in various regions of the United States for domestic coal sales. In addition, we face competition from foreign and domestic producers that sell their coal in the international coal markets. The most important factors on which we compete are delivered price (*i.e.*, the cost of coal delivered to the customer, including transportation costs, which are generally paid by our customers either directly or indirectly), coal quality characteristics, contract flexibility (*e.g.*, volume optionality and multiple supply sources), and reliability of supply. Some competitors may have, among other things, larger financial and operating resources, lower per ton cost of production, or relationships with specific transportation providers. The competition among coal producers may impact our ability to retain or attract customers and could adversely impact our revenues and cash available for distribution.

We sell coal to the export thermal and metallurgical coal market, both of which are significantly affected by international demand and competition. Consolidation in the coal industry, or current or future bankruptcy proceedings of coal competitors may adversely affect us. If overcapacity continues, the prices of and demand for our coal could significantly decline further, which could have a material adverse effect on our business, financial condition, results of operations and cash flows, and could reduce our revenues and cash available for distribution.

In addition, we face competition from foreign producers that sell their coal in the export market. Potential changes to international trade agreements, trade concessions or other political and economic arrangements may benefit coal producers operating in countries other than the United States. We may be adversely impacted on the basis of price or other factors by foreign trade policies or other arrangements that benefit competitors. In addition, coal is sold internationally in United States dollars and, as a result, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide our foreign competitors with a competitive advantage. If our competitors' currencies decline against the

United States dollar or against foreign purchasers' local currencies, those competitors may be able to offer lower prices for coal to those purchasers. Furthermore, if the currencies of overseas purchasers were to significantly decline in value in comparison to the United States dollar, those purchasers may seek decreased prices for the coal we sell. Consequently, currency fluctuations could adversely affect the competitiveness of our coal in international markets, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

New tariffs and other trade measures could adversely affect our results of operations, financial position, and cash flows.

New tariffs and other trade measures could adversely affect our results of operations, financial position and cash flows. The Trump Administration has imposed tariffs on steel and aluminum and a broad range of other products imported into the United States. In response to the tariffs imposed by the United States, the European Union, Canada, Mexico, and China have imposed tariffs on United States goods and services. The new tariffs, along with any additional tariffs or trade restrictions that may be implemented by the United States or retaliatory trade measures or tariffs implemented by other countries, could result in reduced economic activity, increased costs in operating our business, reduced demand and changes in purchasing behaviors for thermal and metallurgical coal, limits on trade with the United States or other potentially adverse economic outcomes. Additionally, we sell coal into the export thermal and metallurgical markets. Accordingly, our international sales may also be impacted by the tariffs and other restrictions on trade between the United States and other countries. While tariffs and other retaliatory trade measures imposed by other countries on United States goods have not yet had a significant impact on our business or results of operations, we cannot predict further developments, and such existing or future tariffs could have a material adverse effect on our results of operations, financial position and cash flows and could reduce our revenues and cash available for distribution.

Changes in consumption patterns by utilities regarding the use of coal have affected our ability to sell the coal we produce.

According to the most recent information from the Energy Information Administration, since 2000, coal's share of United States electricity production has fallen from 53% to 24%, while natural gas' share has increased from 16% to 39%. The domestic electric utility industry accounts for over 91.8% of domestic coal 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 fuel oil as well as alternative sources of energy. Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed in the United States to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain.

Future environmental regulation of GHG emissions also could accelerate the use by utilities of fuels other than coal. In addition, federal and state mandates for increased use of electricity derived from renewable energy sources could affect demand for coal. For example, to the extent implemented as originally finalized, the EPA's CPP could likely incentivize additional electric generation from natural gas and renewable sources, and Congress has extended tax credits for renewables. In addition, a number of states have enacted mandates that require electricity suppliers to rely on renewable energy sources in generating a certain percentage of power. Such mandates, combined with other incentives to use renewable energy sources such as tax credits, could make alternative fuel sources more competitive with coal. A decrease in coal consumption by the domestic electric utility industry could adversely affect the price of coal, which could negatively impact our results of operations and reduce our cash available for distribution.

Extensive environmental laws and regulations affect coal consumers, and have corresponding effects on the demand for coal as a fuel source.

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 coal-fired electric power plants, which are the ultimate consumers of much of our coal. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. These laws and regulations may affect demand and prices for coal. There is also continuing pressure on federal and state regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. Further, far-reaching federal regulations promulgated by the EPA in the last several years, such as CSAPR and MATS, have led to the premature retirement of coal-fired generating units and a significant reduction in the amount of coal-fired generating capacity in the United States Please read "Item 1.

Business—Environmental, Health and Safety Regulations—*Air Emissions*," "—*Carbon Dioxide Emissions*" and "—*Hazardous Substances and Wastes*."

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs, additional operating restrictions or delays, and fewer potential drilling locations, which could adversely affect revenues from our mineral interests.

Oil & gas production on the properties in which we hold mineral interests utilizes hydraulic fracturing. Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations, including shales. The process involves the injection of water, sand, and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal SDWA regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic-fracturing process is typically regulated by state oil & gas commissions.

Several states where we own interests, including Texas and Oklahoma, have adopted regulations that could restrict or prohibit hydraulic fracturing in certain circumstances or require the disclosure of the composition of hydraulic-fracturing fluids. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We cannot predict what additional state or local requirements may be imposed in the future on oil & gas operations in the states in which we own interests. In the event state, local, or municipal legal restrictions are adopted in areas where our operators conduct operations, our operators may incur substantial costs to comply with these requirements, which may be significant in nature, experience delays, or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from the drilling of wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to increased risks of induced seismicity, the use of fracturing fluids, impacts on drinking water supplies, use of water, and the potential for impacts to surface water, groundwater, and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic-fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, those laws could make it more difficult or costly for our operators to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities on our properties could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, and also to attendant permitting delays and potential increases in costs. Legislative changes could cause operators to incur substantial compliance costs and adversely affect revenues from our mineral interests. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Legislation or regulatory initiatives intended to address seismic activity could restrict our operators' drilling and production activities, as well as their ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our minerals segment.

State and federal regulatory agencies have recently focused on a possible connection between the hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil & gas activity and induced seismicity. For example, in 2015, the United States Geological Study identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil & gas extraction.

In addition, a number of lawsuits have been filed in other states, including in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, in October 2014, the Railroad Commission published a new rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may take a range of measures including denying, modifying, suspending or terminating either the permit application or the existing operating permit for that well, or substantially limiting operations under the existing permit in ways that render the continued operation of the well uneconomic. The Railroad Commission has used this authority to deny permits for waste disposal wells. In some instances, regulators may also order that disposal wells be shut-in. For example, in September 2016 the Oklahoma Corporations Commission ordered that all disposal wells with a certain proximity to a particular earthquake in central Oklahoma be shut-in.

The adoption or implementation of any new laws or regulations that restrict our operators' ability to use hydraulic fracturing or dispose of produced water gathered from drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring our operators to shut down or limit the operation of disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

Increased regulation to address climate change (particularly GHG emissions) and uncertainty regarding such regulation could result in increased operating costs and reduced demand for coal or oil & gas as a fuel source, which could reduce demand for our products, decrease our revenues, and reduce our profitability.

Combustion of fossil fuels, such as the coal we produce and the oil & gas produced from our mineral interests, results in the emission of carbon dioxide into the atmosphere. Concerns about the environmental impacts of such emissions, including perceived impacts on global climate issues, are resulting in increased regulation of fossil fuels in many jurisdictions, unfavorable lending policies by lending institutions 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. Some scientists have concluded 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. Increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions due to fossil fuels.

Federal and possibly state governments may impose significant restrictions on fossil-fuel exploration, production and use if pledges made by certain candidates seeking various political offices were enacted into law. Some proposals include bans on hydraulic fracturing of oil & gas wells, bans on new leases for production of minerals on federal properties, and imposing restrictive requirements on new pipeline infrastructure or fossil-fuel export facilities. Other energy legislation and initiatives could include a carbon tax or cap and trade program. Further, although Congress has not passed such legislation, almost half of the states have begun to address GHG emissions, primarily through the planned development of emissions inventories or regional GHG cap and trade programs. Depending on the particular program, we could be required to control GHG emissions or to purchase and surrender allowances for GHG emissions resulting from our operations. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sued companies engaged in the exploration and production of fossil fuels in state and federal courts, alleging various legal theories to recover for the impacts of alleged global warming effects, such as rising sea levels. Many of these suits allege that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts. Although a number of these lawsuits have been dismissed, others remain pending and the outcome of these cases remains difficult to predict.

Apart from governmental regulation, there are also increasing financial risks for fossil fuel producers as stakeholders of fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their support into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. In recent years, the insurance industry has been subject to similar intense lobbying efforts by environmental activist to restrict coverages available for fossil fuel producers. Limitation of investments in and financing, bonding and insurance coverages for fossil fuel energy companies could adversely affect mining or oil & gas production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from fossil fuel companies could result in increased costs of compliance or costs of consuming, and thereby reduce demand for coal and oil & gas, which could reduce the profitability of our interests. Additionally, political, litigation and financial risks may result in either us our oil & gas operators restricting or cancelling mining or oil & gas production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments, as well as concerted conservation and efficiency efforts that result in reduced electricity consumption, and consumer and corporate preferences for non-fossil fuel sources, including alternative energy sources, could cause prices and sales of our coal and/or oil & gas to materially decline and could cause our costs to increase and adversely affect our revenues and results of operations.

The stability and profitability of our operations could be adversely affected if our customers do not honor existing contracts or do not extend existing or enter into new long-term contracts for coal.

In 2019, we sold approximately 78.5% of our coal sales tonnage under contracts having a term greater than one year, which we refer to as long-term sales contracts. These contracts have historically provided a relatively secure market for the production committed under the terms of the contracts. From time to time industry conditions may make it more difficult for us to enter into long-term contracts with our electric utility customers, and if supply exceeds demand in the coal industry, electric utilities may become less willing to lock in price or quantity commitments for an extended period of time. Accordingly, we may not be able to continue to obtain long-term sales contracts with reliable customers as existing contracts expire, which could subject a portion of our revenue stream to the increased volatility of the spot market.

Some of our long-term coal sales contracts contain provisions allowing for the renegotiation of prices and, in some instances, the termination of the contract or the suspension of purchases by customers.

Some of our long-term contracts contain provisions that allow for the purchase price to be renegotiated at periodic intervals. These price reopener provisions may automatically set a new price based on the prevailing market price or, in some instances, require the parties to the contract to agree on a new price. Any adjustment or renegotiation leading to a significantly lower contract price could adversely affect our operating profit margins. Accordingly, long-term contracts may provide only limited protection during adverse market conditions. In some circumstances, failure of the parties to agree on a price under a reopener provision can also lead to early termination of a contract.

Several of our long-term contracts also contain provisions that allow the customer to suspend or terminate performance under the contract upon the occurrence or continuation of certain events that are beyond the customer's reasonable control. Such events may include labor disputes, mechanical malfunctions, and changes in government regulations, including changes in environmental regulations rendering use of our coal inconsistent with the customer's environmental compliance strategies. Additionally, most of our long-term contracts contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics. Failure to meet these specifications can result in economic penalties, rejection or suspension of shipments or termination of the contracts. In the event of early termination of any of our long-term contracts, if we are unable to enter into new contracts on similar terms, our business, financial condition, and results of operations could be adversely affected.

We depend on a few customers for a significant portion of our revenues, and the loss of one or more significant customers could affect our ability to maintain the sales volume and price of the coal we produce.

During 2019, we derived more than 10.0% of our total revenues from each of two customers, Louisville Gas and Electric Company and FirstEnergy Corp. If we were to lose these or any of our significant customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to decrease the amounts of coal purchased or change the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition, and results of operations.

Litigation resulting from disputes with our customers may result in substantial costs, liabilities and loss of revenues.

From time to time we have disputes with our customers over the provisions of long-term coal supply contracts relating to, among other things, coal pricing, quality, quantity, and the existence of specified conditions beyond our or our customers' control that suspend performance obligations under the particular contract. Disputes may occur in the future and we may not be able to resolve those disputes in a satisfactory manner, which could have a material adverse effect on our business, financial condition, and results of operations. See "Item 3. Legal Proceedings."

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If the creditworthiness of our customers declines significantly, our business could be adversely affected. In addition, if a customer refuses to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored. See "Item 3. Legal Proceedings."

Our profitability may decline due to unanticipated mine operating conditions and other events that are not within our control and that may not be fully covered under our insurance policies.

Our coal mining operations are influenced by changing conditions or events that can affect production levels and costs at particular mines for varying lengths of time and, as a result, can diminish our profitability. These conditions and events include, among others:

- mining and processing equipment failures and unexpected maintenance problems;
- unavailability of required equipment;
- prices for fuel, steel, explosives, and other supplies;
- fines and penalties incurred as a result of alleged violations of environmental and safety laws and regulations;
- variations in thickness of the layer, or seam, of coal;
- amounts of overburden, partings, rock, and other natural materials;
- weather conditions, such as heavy rains, flooding, ice and other natural events affecting operations, transportation, or customers;
- accidental mine water discharges and other geological conditions;
- fires;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;
- employee injuries or fatalities;
- labor-related interruptions;
- increased reclamation costs;
- inability to acquire, maintain or renew mining rights or permits in a timely manner, if at all;
- fluctuations in transportation costs and the availability or reliability of transportation; and
- unexpected operational interruptions due to other factors.

These conditions have the potential to significantly impact our operating results. Prolonged disruption of production at any of our mines would result in a decrease in our revenues and profitability, which could materially adversely impact our quarterly or annual results.

Effective October 1, 2019, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance, LLC ("Wildcat Insurance"). Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market at a reduced cost. The maximum limit in the commercial property program is $100.0 million per occurrence excluding a $1.5 million deductible for property damage, a 60, 75, 90 or 120-day waiting period for underground business interruption depending on the mining complex and an additional $10.0 million overall aggregate deductible. We have elected to retain a 10% participating interest in our commercial property insurance program. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations, or ability to purchase property insurance in the future.

Our inability to obtain commercial insurance at acceptable rates or our failure to adequately reserve for self-insured exposures might increase our expenses and have a negative impact on our business.

We believe that commercial insurance coverage is prudent in certain areas of our business for risk management. Insurance costs may increase substantially in the future and may be affected by natural disasters, fear of terrorism, financial irregularities, cybersecurity breaches and other fraud at publicly-traded companies, intervention by the government, an increase in the number of claims received by the carriers, and a decrease in the number of insurance carriers. In addition, the carriers with which we hold our policies may go out of business or be otherwise unable to fulfill their contractual obligations, or may disagree with our interpretation of the coverage or the amounts owed. In addition, for certain types or levels of risk, such as risks associated with certain natural disasters or terrorist attacks, we may determine that we cannot obtain commercial insurance at acceptable rates, if at all. Therefore, we may choose to forego or limit our purchase of relevant commercial insurance, choosing instead to self-insure one or more types or levels of risks. If we suffer a substantial loss that is not covered by commercial insurance or our self-insurance reserves, the loss and related expenses could harm our business and operating results. Also, exposures exist for which no insurance may be available and for which we have not reserved. In addition, environmental activists may try to hamper fossil fuel companies by other means including pressuring insurance and surety companies into restricting access to certain needed coverages.

Although none of our employees are members of unions, our work force may not remain union-free in the future.

None of our employees are represented under collective bargaining agreements. However, all of our work force may not remain union-free in the future, and legislative, regulatory or other governmental action could make it more difficult to remain union-free. If some or all of our currently union-free operations were to become unionized, it could adversely affect our productivity and increase the risk of work stoppages at our mining complexes. In addition, even if we remain union-free, our operations may still be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our operations.

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

We are subject to numerous federal, state, and local laws and regulations affecting the coal mining industry, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air and water quality standards, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge or release of materials into the environment, surface subsidence from underground mining, and the effects that mining has on groundwater quality and availability. Certain of these laws and regulations may impose strict liability without regard to fault or legality of the original conduct. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial liabilities, and the issuance of injunctions limiting or prohibiting the performance of operations. Complying with these laws and regulations may be costly and time consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations may be adopted, or that judicial interpretations or more stringent enforcement of existing laws and regulations may occur, which could materially affect our mining operations, cash flow, and profitability, either through direct impacts on our mining operations, or indirect impacts that discourage or limit our customers' use of coal. Please read "Item 1. Business—Environmental, Health and Safety Regulations."

Federal and state laws addressing mine safety practices impose stringent reporting requirements and civil and criminal penalties for violations. Federal and state regulatory agencies continue to interpret and implement these laws and propose new regulations and standards. Implementing and complying with these laws and regulations has increased and will continue to increase our operational expense and have an adverse effect on our results of operation and financial position. For more information, please read "Item 1. Business—Environmental, Health and Safety Regulations—*Mine Health and Safety Laws*."

We may be unable to obtain and renew permits necessary for our coal mining operations, which could reduce our production, cash flow and profitability.

Mining companies must obtain numerous governmental permits or approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. The public has the right to comment on permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required to conduct our operations may not be issued, maintained or renewed, or may not be issued or renewed in a timely fashion, or may involve requirements that restrict our ability to economically conduct our mining operations. Limitations on our ability to conduct our mining operations due to the inability to obtain or renew necessary permits or similar approvals could reduce our production, cash flow and profitability. Please read "Item 1. Business—Environmental, Health and Safety Regulations—*Mining Permits and Approvals*."

The EPA has begun reviewing permits required for the discharge of overburden from mining operations under Section 404 of the CWA. Various initiatives by the EPA regarding these permits have increased the time required to obtain and the costs of complying with such permits. In addition, the EPA previously exercised its "veto" power to withdraw or restrict the use of previously issued permits in connection with one of the largest surface mining operations in Appalachia. The EPA's action was ultimately upheld by a federal court. As a result of these developments, we may be unable to obtain or experience delays in securing, utilizing or renewing Section 404 permits required for our operations, which could have an adverse effect on our results of operation and financial position. Please read "Item 1. Business—Environmental, Health and Safety Regulations—*Water Discharge*."

In addition, some of our permits could be subject to challenges from the public, which could result in additional costs or delays in the permitting process, or even an inability to obtain permits, permit modifications, or permit renewals necessary for our operations.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce revenues by causing us to reduce our production or by impairing our ability to supply coal to our customers.

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 source of energy or could make our coal production less competitive than coal produced from other sources. Disruption of transportation services due to weather-related problems, flooding, drought, accidents, mechanical difficulties, strikes, lockouts, bottlenecks or other events could temporarily impair our ability to supply coal to our customers. Our transportation providers may face difficulties in the future that may impair our ability to supply coal to our customers, resulting in decreased revenues. If there are disruptions of the transportation services provided by our primary rail or barge carriers that transport our coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. For instance, difficulty in coordinating the many eastern 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 coal shipments originating in the eastern United States inherently more expensive on a per-mile basis than coal shipments originating in the western United States. Historically, high coal transportation rates from the western coal producing areas into certain eastern markets limited the use of western coal in those markets. Lower rail rates from the western coal producing areas to markets served by eastern United States coal producers have created major competitive challenges for eastern coal producers. In the event of further reductions in transportation costs from western coal producing areas, the increased competition with certain eastern coal markets could have a material adverse effect on our business, financial condition, and results of operations.

It is possible that states in which our coal is transported by truck may modify or increase enforcement of their laws regarding weight limits or coal trucks on public roads. 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 revenues.

We may not be able to successfully grow our coal business through future acquisitions.

Since our formation and the acquisition of our predecessor in August 1999, we have expanded our coal operations by adding and developing mines and coal reserves in existing, adjacent, and neighboring properties. Our future growth could be limited if we are unable to continue to make acquisitions, or if we are unable to successfully integrate the companies, businesses or properties we acquire. We may not be successful in consummating any acquisitions and the consequences of undertaking these acquisitions are unknown. Moreover, any acquisition could be dilutive to earnings and distributions to unitholders and any additional debt incurred to finance an acquisition could affect our ability to make distributions to unitholders. Our ability to make acquisitions in the future could require significant amounts of financing that may not be available to us under acceptable terms and may be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

The unavailability of an adequate supply of coal reserves that can be mined at competitive costs could cause our profitability to decline.

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because we deplete our reserves as we mine coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. Replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those 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 profitability and financial condition. Exhaustion of reserves at particular mines 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.

The estimates of our coal reserves may prove inaccurate and could result in decreased profitability.

The estimates of our coal reserves may vary substantially from actual amounts of coal we are able to economically recover. The reserve data set forth in "Item 2. Properties" represent our engineering estimates. All of the reserves presented in this Annual Report on Form 10-K constitute proven and probable reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may vary considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data and/or differ from our experiences in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulation and taxes by governmental agencies;
- future improvements in mining technology; and
- assumptions concerning future coal prices, operating costs, capital expenditures, severance and excise taxes, and development and reclamation costs.

For these reasons, estimates of the recoverable quantities of coal attributable to any particular group of properties, classifications of reserves based on risk of recovery, and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. Any inaccuracy in the estimates of our reserves could result in higher than expected costs and decreased profitability.

Coal mining in certain areas in which we operate is more difficult and involves more regulatory constraints than mining in other areas of the United States, which could affect the mining operations and cost structures of these areas.

The geological characteristics of some of our coal reserves, such as depth of overburden and coal seam thickness, make them difficult and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those characteristic of the depleting mines. In addition, permitting, licensing, and other environmental and regulatory requirements associated with certain of our mining operations are more costly and time-consuming to satisfy. Subsidence issues are particularly important to our operations engaged in longwall mining. Failure to timely and economically secure subsidence rights or any associated mitigation agreements could materially affect our results by causing delays or changes in our mining plan. These factors could materially adversely affect the mining operations and cost structures of, and our customers' ability to use coal produced by, our mines.

Some of our operating subsidiaries lease a portion of the surface properties upon which their mining facilities are located.

Our operating subsidiaries do not, in all instances, own all of the surface properties upon which their mining facilities have been constructed. Certain of the operating companies have constructed and now operate all or some portion of their facilities on properties owned by unrelated third parties with whom our subsidiary has entered into a long-term lease. We have no reason to believe that there exists any risk of loss of these leasehold rights given the terms and provisions of the subject leases and the nature and identity of the third-party lessors; however, in the unlikely event of any loss of these leasehold rights, operations could be disrupted or otherwise adversely impacted as a result of increased costs associated with retaining the necessary land use.

Unexpected increases in raw material costs could significantly impair our operating profitability.

Our coal mining operations are affected by commodity prices. We use significant amounts of steel, petroleum products, and other raw materials in various pieces of mining equipment, supplies, and materials, including the roof bolts required by the room-and-pillar method of mining. 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. There may be acts of nature or terrorist attacks or threats that could also impact the future costs of raw materials. Future volatility in the price of steel, petroleum products, or other raw materials will impact our operational expenses and could result in significant fluctuations in our profitability.

Federal and state laws require bonds to secure our obligations related to statutory reclamation requirements and workers' compensation and black lung benefits. Our inability to acquire or failure to maintain surety bonds that are required by federal and state law would have a material adverse effect on us.

Federal and state laws require us 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 "reclaim" or "reclamation"), to pay federal and state workers' compensation and pneumoconiosis (or black lung) benefits, and to satisfy other miscellaneous obligations. These bonds provide assurance that we will perform our statutorily required obligations and are referred to as "surety" bonds. These bonds are typically renewable on a yearly basis. The failure to maintain or the inability to acquire sufficient surety bonds, as required by federal and state laws, could subject us to fines and penalties and result in the loss of our mining permits. Such failure could result from a variety of factors, including:

- lack of availability, higher expense or unreasonable terms of new surety bonds, including as a result of external pressures related to fossil fuel companies;
- the ability of current and future surety bond issuers to increase required collateral, or limitations on availability of collateral for surety bond issuers due to the terms of our credit agreements; and
- the exercise by third-party surety bond holders of their rights to refuse to renew the surety.

We have outstanding surety bonds with governmental agencies for reclamation, federal and state workers' compensation, and other obligations. At December 31, 2019, our total of such bonds was $279.6 million. We may have difficulty maintaining our surety bonds for mine reclamation as well as workers' compensation and black lung benefits. In addition, those governmental agencies may increase the amount of bonding required. Our inability to acquire or failure to maintain these bonds, or a substantial increase in the bonding requirements, would have a material adverse effect on us.

Price fluctuations in the oil & gas industry could affect our profitability and distributable cash flow.

We have investments in oil & gas mineral interests in the continental United States. Consequently, the value of the investments as well as any resulting cash flows, may fluctuate with changes in the market and prices for oil & gas. Since we began these investments in late 2014, the oil & gas industry has experienced significant fluctuations in commodity prices driven by a global supply/demand imbalance for oil and an oversupply of natural gas in the United States. If commodity prices decline to lower levels, we could see a decrease in the value of these investments or in the cash flows they generate. For more information on our involvement in these matters, please read "Item 8. Financial Statements and Supplementary Data—Note 12 – Investments."

We depend on unaffiliated operators for all of the exploration, development and production on the oil & gas properties in which we own mineral interests.

Because we depend on our third-party operators for all of the exploration, development and production on our oil & gas properties, we have little to no control over the operations related to our oil & gas properties. The operators of our properties are often not obligated to undertake any development activities. In the absence of a specific contractual obligation, any development and production activities will be subject to their sole discretion (subject, however, to certain implied obligations to develop imposed by state law). The success and timing of drilling and development activities on our oil & gas properties, and whether the operators elect to drill any additional wells on our acreage, depends on a number of factors that will be largely outside of our control, including:

- the capital costs required for drilling activities by the operators of our oil & gas properties, which could be significantly more than anticipated;
- the ability of the operators of our properties to access capital;
- prevailing commodity prices;
- the availability of suitable drilling equipment, production and transportation infrastructure, and qualified operating personnel;
- the operators' expertise, operating efficiency, and financial resources;
- approval of other participants in drilling wells;
- the operators' expected return on investment in wells drilled on our acreage as compared to opportunities in other areas;
- the selection of technology;
- the selection of counterparties for the marketing and sale of production; and
- the rate of production of the reserves.

The operators may elect not to undertake development activities, or may undertake these activities in an unanticipated fashion, which may result in significant fluctuations in our oil & gas revenues and cash available for distribution.

We have little to no control over the timing of future drilling with respect to our mineral interests.

All of our oil & gas mineral interests may not ultimately be developed or produced by the operators of our properties. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations, and the decision to pursue development of an undeveloped drilling location will be made by the operator and not by us. We generally do not have access to the estimated costs of development of these reserves or the scheduled development plans of our operators. The reserve data included in the reserve report assumes that substantial capital expenditures are required to develop the reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of the development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop our reserves, or decreases in commodity prices will reduce the future net revenues of our estimated undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved undeveloped reserves as unproved reserves.

We may experience delays in the payment of royalties and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy.

A failure on the part of the operators to make royalty payments gives us the right to terminate the lease and enforce payment obligations under the lease. If we terminate any of our leases, we would seek a replacement operator. However, we might not be able to find a replacement operator and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to a proceeding under Title 11 of the United States Code (the "Bankruptcy Code"), in which case our right to enforce or terminate the lease for any defaults, including non-payment, may be substantially delayed or otherwise impaired. In general, in a proceeding under the Bankruptcy Code, the bankrupt operator would have substantial time to decide whether they ultimately reject or assume the lease, which could prevent the execution of a new lease or the assignment of the existing lease to another operator. In the event that the operator rejected the lease, our ability to collect amounts owed would be substantially delayed, and our ultimate recovery may be only a fraction of the amount owed or nothing. In addition, if we are able to enter into a new lease with a new operator, the replacement operator may not achieve the same levels of production or sell oil or natural gas at the same price as the operator it replaced.

If the operators of our properties suspend our right to receive royalty payments due to title or other issues, our business, financial condition and/or results of operations may be adversely affected.

Upon a change in ownership of mineral interests, and at regular intervals pursuant to routine audit procedures at each of our operators otherwise at its discretion, the operator of the underlying property has the right to investigate and verify the title and ownership of mineral interests with respect to the properties it operates. If any title or ownership issues are not resolved to its reasonable satisfaction in accordance with customary industry standards, the operator may suspend payment of the related royalty. If an operator of our properties is not satisfied with the documentation we provide to validate our ownership, it may place our royalty payment in suspense until such issues are resolved, at which time we would receive in full payments that would have been made during the suspense period, without interest. Certain of our operators impose significant documentation requirements for title transfer and may keep royalty payments in suspense for significant periods of time. During the time that an operator puts our assets in pay suspense, we would not receive the applicable mineral or royalty payment owed to us from sales of the underlying oil or natural gas related to such mineral or royalty interest. If a significant amount of our royalty interests are placed in suspense, our results of operations may be reduced significantly.

The inability to successfully identify, complete and integrate acquisitions of additional oil & gas mineral interests could cause our profitability to decline.

Our profitability depends partly upon acquisitions to grow our oil & gas reserves, production, and free cash flow. Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data, and other information, the results of which are often inconclusive and subject to various interpretations. The successful acquisition of properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil & gas prices and their applicable basis differentials;
- development plans;
- the operating costs our operators would incur to develop and operate the properties; and
- potential environmental and other liabilities that operators of the properties may incur.

The accuracy of these assessments is inherently uncertain and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices, given the nature of our interests. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing. In addition, these acquisitions may be in geographic regions in which we do not currently hold properties, which could subject us to additional and unfamiliar legal and regulatory requirements. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired assets into our existing operations. The process of integrating acquired assets may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms, or successfully acquire identified targets.

Any acquisitions of additional mineral interests that we complete will be subject to substantial risks.

Even if we make acquisitions that we believe will increase our mineral revenue, any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, prices, revenues, capital expenditures, the operating expenses and costs our operators would incur to develop the minerals;
- a decrease in our liquidity by using a significant portion of our cash generated from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- mistaken assumptions about the overall cost of equity or debt;
- our ability to obtain satisfactory title to the assets we acquire;

- an inability to hire, train or retain qualified personnel to manage and operate our growing mineral assets; and
- the occurrence of other significant changes, such as impairment of oil & gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges.

Our estimated oil & gas reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil & gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil & gas and assumptions concerning future oil & gas prices, production levels, ultimate recoveries and operating costs. As a result, estimated quantities of proved reserves and projections of future production rates may be incorrect. Our estimates of proved reserves and related valuations as of December 31, 2019 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), which conducted a detailed review of all of our properties at that time using information provided by us. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing and production. In addition, certain assumptions regarding future oil & gas prices, production levels and operating costs may prove incorrect. A meaningful portion of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves and future cash generated from operations. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil & gas that are ultimately recovered being different from our reserve estimates.

Furthermore, the present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. In accordance with rules established by the SEC and the Financial Accounting Standards Board, we base the estimated discounted future net cash flows from our proved reserves on the twelve-month average oil & gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month, and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate, and future net present value estimates using then-current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil & gas industry in general. Please see "Item 2. Properties" for more information on our reserves.

Drilling for and producing oil & gas are high-risk activities with many uncertainties that may materially adversely affect our business, financial condition and results of operations.

The drilling activities of the operators of our properties will be subject to many risks. For example, we will not be able to assure our unitholders that wells drilled by the operators of our properties will be productive. Drilling for oil & gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or gas to return a profit at then realized prices after deducting drilling, operating, and other costs. The seismic data and other technologies used do not provide conclusive knowledge prior to drilling a well that oil or gas is present or that it can be produced economically. The costs of exploration, exploitation, and development activities are subject to numerous uncertainties beyond our control and increases in those costs can adversely affect the economics of a project. Further, our operators' drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations or earthquakes;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources, and equipment, pollution, environmental contamination or loss of wells, and other regulatory penalties. In the event that planned operations, including the drilling of development wells, are delayed or cancelled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition, results of operations, and free cash flow may be materially adversely affected.

The marketability of oil & gas production is dependent upon transportation and other facilities, certain of which neither we nor the operators of our properties control. If these facilities are unavailable, our operators' operations could be interrupted and our results of operations and cash available for distribution could be materially adversely affected.

The marketability of our operators' oil & gas production will depend in part upon the availability, proximity and capacity of transportation facilities, including gathering systems, trucks and pipelines, owned by third parties. Neither we nor, in general, the operators of our properties control these third party transportation facilities and our operators' access to them may be limited or denied. Insufficient production from the wells on our acreage or a significant disruption in the availability of third party transportation facilities or other production facilities could adversely impact our operators' ability to deliver to market or produce oil & gas and thereby cause a significant interruption in our operators' operations. If they are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, they may be required to shut-in or curtail production. In addition, the amount of oil & gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our or our operators' control, such as pipeline interruptions due to maintenance, excessive pressure, inability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering system or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we and our operators are provided with limited notice, if any, as to when these curtailments will arise and the duration of such curtailments. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil & gas produced from our acreage, could adversely affect our financial condition, results of operations, and cash available for distribution.

We do not currently enter into hedging arrangements with respect to the oil & gas production from our properties, and we will be exposed to the impact of decreases in the price of oil & gas.

We have not entered into hedging arrangements to establish, in advance, a price for the sale of the oil & gas produced from our properties, and we may not enter into such arrangements in the future. As a result, although we may realize the benefit of any short-term increase in the price of oil & gas, we will not be protected against decreases in the price of oil & gas or prolonged periods of low commodity prices, which could materially adversely affect our business, results of operation and cash available for distribution.

In the future, we may enter into hedging transactions with the intent of reducing volatility in our cash flows due to fluctuations in the price of oil & gas. However, these hedging activities may not be as effective as we intend in reducing the volatility of our cash flows and, if entered into, are subject to the risks that the terms of the derivative instruments will be imperfect, a counterparty may not perform its obligations under a derivative contract, there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received, our hedging policies and procedures may not be properly followed and the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. Further, we may be limited in receiving the full benefit of increases in oil & gas prices as a result of these hedging transactions. The occurrence of any of these risks could prevent us from realizing the benefit of a derivative contract.

Oil & gas operations are subject to various governmental laws and regulations. Compliance with these laws and regulations can be burdensome and expensive for our operators, and failure to comply could result in our operators incurring significant liabilities, either of which may impact our operators' willingness to develop our interests.

Our operators' operations on the properties in which we hold interests are subject to various federal, state, and local governmental regulations that may change from time to time in response to economic and political conditions. Matters subject to regulation include drilling operations, production and distribution activities, discharges or releases of pollutants or wastes, plugging and abandonment of wells, maintenance and decommissioning of other facilities, the spacing of wells, unitization and pooling of properties, and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil & gas wells below actual production capacity to conserve supplies of oil & gas. In addition, the production, handling, storage and transportation of oil & gas, as well as the remediation, emission, and disposal of oil & gas wastes, by-products thereof and other substances and materials produced or used in connection with oil & gas operations are subject to regulation under federal, state, and local laws and regulations primarily relating to protection of worker health and safety, natural resources, and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions on our operators, including administrative, civil, or criminal penalties, permit revocations, requirements for additional pollution controls, and injunctions limiting or prohibiting some or all of our operators' operations on our properties. Moreover, these laws and regulations have generally imposed increasingly strict requirements related to water use and disposal, air pollution control, and waste management. Laws and regulations governing exploration and production may also affect production levels. Our operators must comply with federal and state laws and regulations governing conservation matters, including:

- provisions related to the unitization or pooling of the oil & gas properties;
- the establishment of maximum rates of production from wells;
- the spacing of wells;
- the plugging and abandonment of wells; and
- the removal of related production equipment.

Additionally, federal and state regulatory authorities may expand or alter applicable pipeline-safety laws and regulations, compliance with which may require increased capital costs for third-party oil & gas transporters. These transporters may attempt to pass on such costs to our operators, which in turn could affect profitability on the properties in which we own mineral interests.

Our operators must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the operators of our properties are shippers on interstate pipelines, they must comply with the tariffs of those pipelines and with federal policies related to the use of interstate capacity. Our operators may be required to make significant expenditures to comply with the governmental laws and regulations described above and may be subject to potential fines and penalties if they are found to have violated these laws and regulations. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. These current laws and regulations and other potential regulations could increase the operating costs of our operators and delay production and may ultimately impact our operators' ability and willingness to develop our properties.

Terrorist attacks or cyber incidents could result in information theft, data corruption, operational disruption and/or financial loss.

Like most companies, we have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our business partners, analyze mine and mining information, estimate quantities of reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the United States. Deliberate attacks on, or security breaches in, our systems or infrastructure, or the systems or infrastructure of third parties could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions, and third-party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, results of operations, and cash flows. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Tax Risks to Our Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, and our not being subject to a material amount of entity-level taxation. 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, our cash available for distribution to you would be substantially reduced.

The anticipated after-tax benefit of an investment in our units depends largely on our being treated as a partnership for United States federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for United States federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations and current Treasury Regulations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for United States federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for United States federal income tax purposes, we would pay United States federal income tax on our taxable income at the corporate tax rate, and would likely be liable for state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because taxes would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of the units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced and the value of our units could be negatively impacted.

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

The present United States federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress have proposed and considered substantive changes to the existing federal income tax laws that affect us or all publicly traded partnerships. For example, enacted legislation repealed Section 199, which, prior to its repeal, entitled our unitholders to a deduction equal to a specified percentage of our qualified production activities income that was allocated to such unitholder. From time to time, members of Congress have proposed and considered substantive changes to the existing United States federal income tax laws that would affect publicly traded partnerships, including elimination of partnership tax treatment for certain publicly traded partnership. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to United States 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 partnership in the future.

Any modification to the United States 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 United States federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any similar or future legislative changes could negatively impact the amount of our unit distributions and the value of an investment in our units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our units, and the costs of any such contest would reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions that we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the prices at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in our cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

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 taxable 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 and 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 pay taxes, penalties and interest, our cash available for distribution to our unitholders may 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.

Even if you do not receive any cash distributions from us, you will be required to pay taxes on your share of our taxable income.

You will be required to pay federal income taxes and, in some cases, state and local income taxes, on your share of our taxable income, whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability which results from your share of our taxable income.

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

If you sell your units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis therein, even if the price you receive is less than your original cost. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, if you sell your 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 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 units if the amount realized on a sale of your units is less than your adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which you sell your 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 units.

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 to the extent such depreciation, amortization or depletion is not capitalized into cost of goods sold with respect to inventory. If our "business interest" is subject to limitation under these rules, our unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Tax-exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as "IRAs") raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from United States federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. 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) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our units.

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

Non-United States unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a United States trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a United States trade or business. As a result, distributions to a Non-United States unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-United States unitholder who sells or otherwise disposes of a unit will also be subject to United States federal income tax on the gain realized from the sale or disposition of that unit.

Moreover, the transferee of an interest in a partnership that is engaged in a United States trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferees but were not withheld. Because the "amount realized" includes a partner's share of the partnership's liabilities, 10% of the amount realized could exceed the total cash purchase price for the units. However, pending the issuance of final regulations, the IRS has suspended the application of this withholding rule to transfers of publicly traded interests in publicly traded partnerships. If recently promulgated regulations are finalized as proposed, such regulations would provide, with respect to transfers of publicly traded interests in publicly traded partnerships effected through a broker, that the obligation to withhold is imposed on the transferor's broker and that a partner's "amount realized" does not include a partner's share of a publicly traded partnership's liabilities for purposes of determining the amount subject to withholding. However, it is not clear when such regulations will be finalized and if they will be finalized in their current form.

We treat each purchaser of our units as having the same tax benefits without regard to the units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of our units.

Because we cannot match transferors and transferees of units, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing 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 units and could have a negative impact on the value of our 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 units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

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

Certain federal income tax deductions currently available with respect to coal mining and production may be eliminated as a result of future legislation.

In past years, members of Congress have indicated a desire to eliminate certain key United States federal income tax provisions currently applicable to coal companies, including the percentage depletion allowance with respect to coal properties. No legislation with that effect has been proposed and elimination of those provisions would not impact our financial statements or results of operations. However, elimination of the provisions could result in unfavorable tax consequences for our unitholders and, as a result, could negatively impact our unit price.

You will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where you do not live as a result of investing in our units.

In addition to United States federal income taxes, you will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if you do not live in any of those jurisdictions. You 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, you may be subject to penalties for failure to comply with those requirements.

We currently own assets and conduct business in a variety of states which currently impose a personal income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, state, and local tax returns and pay any taxes due in these jurisdictions. You should consult with your tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Coal Reserves

We must obtain permits from applicable regulatory authorities before beginning to mine particular reserves. For more information on this permitting process, and matters that could hinder or delay the process, please read "Item 1. Business—Environmental, Health and Safety Regulations—*Mining Permits and Approvals*."

Our reported coal reserves are those we believe can be economically and legally extracted or produced at the time of the filing of this Annual Report on Form 10-K. In determining whether our reserves meet this economic and legal standard, we take into account, among other things, our potential ability or inability to obtain mining permits, the possible necessity of revising mining plans, changes in future cash flows caused by changes in estimated future costs, changes in mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices.

At December 31, 2019, we had approximately 1.693 billion tons of coal reserves. All of the estimates of reserves which are presented in this Annual Report on Form 10-K are of proven and probable reserves (as defined below) and closely adhere to the standards described in United States Geological Survey ("USGS") Circular 831 and USGS Bulletin 1450-B. For information on the locations of our mines, please read "Coal Operations" under "Item 1. Business."

The following table sets forth reserve information at December 31, 2019 about our coal operations:

			Pounds S02 per MMBtu				Classification		Reserve Assignment		Reserve Control	
Operations (1)	Mine Status (2)	Heat Content (Btus per pound)	<1.2	1.2-2.5	>2.5	Total	Proven	Probable	Assigned	Unassigned	Owned	Leased
			(tons in millions)									
Illinois Basin Operations												
Gibson (South) (IN)	A	11,500	1.1	13.5	41.1	55.7	47.8	7.9	55.7	—	18.2	37.5
Hamilton County (IL)	A	11,650	—	—	535.1	535.1	234.3	300.8	123.9	411.2	51.7	483.4
Henderson/Union (KY)	R	11,400	—	3.1	457.3	460.4	170.8	289.6	—	460.4	63.4	397.0
River View (KY)	A	11,450	—	—	232.7	232.7	127.0	105.7	232.7	—	69.1	163.6
Warrior (KY)	A	12,300	—	—	89.7	89.7	72.2	17.5	89.7	—	21.9	67.8
Dotiki (KY)	C	12,100	—	2.9	73.2	76.1	52.4	23.7	—	76.1	27.6	48.5
Gibson (North) (IN)	C	11,500	—	6.7	15.0	21.7	17.2	4.5	21.7	—	0.6	21.1
Hopkins (KY)	C	12,000	—	—	13.9	13.9	9.7	4.2	—	13.9	4.4	9.5
Sebree - Onton (KY)	C	11,750	—	—	40.3	40.3	22.6	17.7	40.3	—	0.2	40.1
Region Total			1.1	26.2	1,498.3	1,525.6	754.0	771.6	564.0	961.6	257.1	1,268.5
Appalachia Operations												
MC Mining (KY)	A	12,600	13.4	2.1	—	15.5	10.7	4.8	15.5	—	0.2	15.3
Mettiki (MD)	A	13,200	—	1.6	3.8	5.4	5.3	0.1	—	5.4	—	5.4
Mettiki (WV)	A	13,200	—	5.5	7.9	13.4	9.3	4.1	7.6	5.8	1.6	11.8
Penn Ridge (PA)	R	12,500	—	—	61.5	61.5	16.7	44.8	61.5	—	61.5	—
Tunnel Ridge (WV)	A	12,600	—	—	71.6	71.6	33.3	38.3	71.6	—	—	71.6
Region Total			13.4	9.2	144.8	167.4	75.3	92.1	156.2	11.2	63.3	104.1
Total			14.5	35.4	1,643.1	1,693.0	829.3	863.7	720.2	972.8	320.4	1,372.6
% of Total			0.9%	2.1%	97.1%	100.0%	49.0%	51.0%	42.5%	57.5%	18.9%	81.1%

(1) Our mining operations, both active and inactive, contain underground mines
(2) A = Active, C = Closed/Idled, R = Reserves only

Our reserve estimates are prepared from geological data assembled and analyzed by our staff of geologists and engineers. This data is obtained through our extensive, ongoing exploration drilling and in-mine channel sampling programs. Our drill spacing criteria adheres to standards as defined by the USGS. The maximum acceptable distance from seam data points varies with the geologic nature of the coal seam being studied, but generally the standard for (a) proven reserves is that points of observation are no greater than ½ mile apart and are projected to extend as a ¼ mile wide belt around each point of measurement and (b) probable reserves is that points of observation are between ½ and 1 ½ miles apart and are projected to extend as a ½ mile wide belt that lies ¼ mile from the points of measurement.

Reserve estimates will change from time to time to reflect mining activities, additional analysis, new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods, and other factors. We have historically obtained an outside audit of our reserve estimates and calculation methods every five years with the most recent audit being performed by Weir International Mining Consultants in July 2015.

Reserves represent that part of a mineral deposit that can be economically and legally extracted or produced, and reflect estimated losses involved in producing a saleable product. All of our reserves are thermal coal, except for reserves at Mettiki that can be delivered to the thermal or metallurgical markets. The 13.4 million tons of reserves listed at MC Mining as <1.2 pounds of SO_2 per MMBtus are marketable as compliance coal under Phase II of CAA. Btu values are reported on an as shipped, fully washed basis. Shipments that are either fully or partially raw will have a lower Btu value.

We own or control certain leases for coal deposits that do not currently meet the criteria to be reflected as reserves but may be reclassified as reserves in the future. These tons are classified as non-reserve coal deposits and are not included in our reported reserves. We have total non-reserve coal deposits of 268.7 million tons of which the Henderson/Union Reserves account for 156.7 million tons. Our remaining non-reserve coal deposits include the following: Dotiki—16.2 million tons, Elk Creek—7.8 million tons, Gibson (South)—1.7 million tons, Hamilton—33.7 million tons, Mettiki—1.0 million tons, Penn Ridge—15.8 million tons, Riverview—3.2 million tons, Sebree - Onton—4.6 million tons, Sebree—7.0 million tons, Tunnel Ridge—16.5 million tons and Warrior—4.5 million tons.

We lease most of our reserves and generally have the right to maintain leases in force until the exhaustion of mineable and merchantable coal located within the leased premises or a larger coal reserve area. These leases provide for royalties to be paid to the lessor at a fixed amount per ton or as a percentage of the sales price. Many leases require payment of minimum royalties, payable either at the time of the execution of the lease or in periodic installments, even if no mining activities have begun. These minimum royalties are normally credited against the production royalties owed to a lessor once coal production has commenced.

Mining Operations

The following table sets forth production and other data about our mining operations:

		Tons Produced				
Operations	**Location**	**2019**	**2018**	**2017**	**Transportation**	**Equipment**
			(in millions)			
Illinois Basin Operations						
Dotiki (1)	Kentucky	1.3	2.5	2.6	CSX, PAL, truck, barge	CM
Gibson (North) (2)	Indiana	1.8	0.9	—	CSX, NS, truck, barge	CM
Gibson (South)	Indiana	5.5	6.9	6.0	CSX, NS, truck, barge	CM
Hamilton	Illinois	5.9	6.3	6.1	CSX, EVW, barge	LW, CM
River View	Kentucky	11.3	9.8	9.0	Truck, barge	CM
Warrior	Kentucky	3.7	3.5	3.6	CSX, PAL, truck, barge	CM
Region Total		29.5	29.9	27.3		
Appalachia Operations						
MC Mining	Kentucky	1.0	1.3	1.4	CSX, truck, barge	CM
Mettiki	WV, MD	2.1	2.3	2.1	CSX, truck	LW, CM
Tunnel Ridge	West Virginia	7.4	6.8	6.8	CSX, NS, barge	LW, CM
Region Total		10.5	10.4	10.3		
TOTAL		40.0	40.3	37.6		

(1) Closed
(2) Idled

CSX	- CSX Railroad
EVW	- Evansville Western Railroad
NS	- Norfolk Southern Railroad
PAL	- Paducah & Louisville Railroad
CM	- Continuous Miner
LW	- Longwall

Oil & Gas Reserves

Our mineral interests are primarily located in three basins, which are also our areas of focus for future development. These include the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) Basins. At December 31, 2019, we had approximately 38,000 developed and undeveloped net acres held at a weighted average royalty of 18.1%. Our net acres standardized to 1/8th royalty equates to approximately 55,700 net royalty acres, including approximately 3,989 net royalty acres owned through our equity interest in AllDale III.

The following table presents our estimated net proved oil & gas reserves, including our share of reserves owned through our equity interest in AllDale III, as of December 31, 2019 based on the reserve reports prepared by NSAI. The reserve report, which is filed as an exhibit to this annual report, has been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve report are located in the continental United States.

	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
Estimated proved developed reserves	5,766	24,449	2,009	11,850
Estimated proved undeveloped reserves	1,383	6,106	709	3,110
Total estimated proved reserves (1)	7,149	30,555	2,718	14,960

(1) As of December 31, 2019, proved reserves of approximately 1,208 MBOE were attributable to noncontrolling interests.

Natural gas reserve volumes are converted to BOE based on a 6:1 ratio: 6 Mcf of natural gas converts to one BOE.

Estimates of reserves as of December 31, 2019, were prepared using product prices equal to the unweighted arithmetic average of the first-day-of-the-month market price for each month in the period from January through December 2019. The average realized product prices weighted by production over the remaining lives of the properties are $52.32 per barrel of oil, $1.83 per Mcf of natural gas and $21.95 per barrel of NGL.

The following table summarizes our changes in proved undeveloped reserves (in MBOE):

Beginning balance, December 31, 2018	253
Acquisitions of proved undeveloped reserves	4,669
Transfers of PUDs to estimated proved developed	(1,061)
Extensions and Discoveries	1,714
Revisions of previous estimates	(2,465)
Ending balance, December 31, 2019	3,110

New PUD reserves totaling 4,669 MBOE were added during the year ended December 31, 2019, resulting from acquisitions. Approximately 3,594 MBOE were acquired through the AllDale Acquisition, primarily in the Permian, Bakken, and Anadarko Basins. An additional 1,075 MBOE of PUD reserves in the Permian was added through the Wing acquisition.

During the year ended December 31, 2019, we converted 1,061 MBOE of PUD reserves to proved developed reserves as applicable wells began production. We had reductions of 2,465 MBOE to our PUD reserves, primarily as a result of updated operator information.

As a mineral interest owner we have no transparency into or control over our operators' investments and operational progress to convert PUDs to proved developed producing reserves. We do not incur any capital expenditures or lease operating expenses in connection with the development of our PUDs, which costs are borne entirely by our operators. As a result, during the year ended December 31, 2019, we did not have any expenditures to convert PUDs to proved developed reserves. PUDs that have not been developed within two years of permitting are reviewed and removed from proved reserves as necessary. As of December 31, 2019, approximately 20.8% of our total proved reserves were classified as PUDs.

Evaluation and Review of Reserves

Numerous uncertainties are inherent in estimating reserve volumes and values, and the estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of the reserves may vary significantly from the original estimates.

Our 2019 year end proved reserves were prepared by NSAI, an independent third-party petroleum engineering firm that does not own an interest in any of our properties and is not employed by us on a contingent basis. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Under SEC rules, proved reserves are those quantities of oil & gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible–from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations–prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2019 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil & gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil & gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods:

(1) performance-based methods,
(2) volumetric-based methods and
(3) analogy.

These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production data. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

To estimate economically recoverable proved reserves and related future net cash flows, NSAI considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

We utilize contract petroleum engineers who worked closely with our third-party reserve engineers to ensure the integrity, accuracy, and timeliness of the data used to calculate our estimated proved reserves. Our contract engineers met with our third-party reserve engineers periodically during the period covered by the above referenced reserve report to discuss the assumptions and methods used in the reserve estimation process. Our contract engineers provided historical information to the third-party reserve engineers for our properties, such as oil & gas production, well test data, and realized commodity prices. Our contract engineers also provided ownership interest information with respect to our properties. Our internal petroleum engineer has over 25 years of engineering and operations experience in the oil & gas sector and is primarily responsible for overseeing the petroleum reserves preparation.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical data, which is based on actual production as reported by our operators;
- internally prepared reserve estimates compared to reserves prepared by third parties;
- review of all our reported proved reserves semi-annually including the review of all significant reserve changes and proved undeveloped reserves additions by our internal petroleum engineer, or those under his direct supervision including our contract engineers;
- review of changes in reserves semi-annually and in comparison to third-party reports by both the Chief Accounting Officer and Chief Financial Officer;
- verification of property ownership by our land department; and
- no employee's compensation is tied to the amount of reserves booked.

Acreage Concentration

Our mineral interests are primarily located in three basins, which are also our areas of focus for future operator development. These include the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) Basins. Below is a chart reflecting our gross, net and net royalty acreage in each of our primary basins as of December 31, 2019.

	Developed Acreage			Undeveloped Acreage		
	Gross	**Net**	**Net Royalty**	**Gross**	**Net**	**Net Royalty**
Basin						
Permian Basin	124,890	2,803	4,291	529,425	13,510	20,748
Anadarko Basin	129,201	4,780	6,815	304,541	11,231	15,993
Williston Basin	102,066	1,690	2,214	126,865	2,036	2,679
Other	20,984	519	670	40,650	1,871	2,306
Total	377,141	9,792	13,990	1,001,481	28,648	41,726

Oil & Gas Production Prices and Production Costs

For the year ended December 31, 2019, 43.2% of our production and 73.2% of our oil & gas revenues were related to oil production and sales, respectively. The following table sets forth information regarding production of oil & gas and certain price and cost information for each of the periods indicated:

		Year Ended December 31, 2019
Production:		
Oil (MBbls)		741
Natural gas (MMcf)		3,664
Natural gas liquids (MBbls)		364
BOE (MBbls)		1,716
Average Realized Prices:		
Oil (per Bbl)	$	54.30
Natural gas (per Mcf)	$	2.01
Natural gas liquids (per Bbl)	$	20.17
BOE (MBbls)	$	32.02
Unit cost per BOE:		
Production and ad valorem taxes	$	4.82

Productive Wells

As of December 31, 2019, 6,309 gross productive horizontal wells and 7,511 gross productive vertical wells were located on the acreage in which we have a mineral interest. Of our productive horizontal wells, 941 are considered natural gas wells, while the remaining 5,368 primarily produce oil. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. We do not own any material working interests in any wells. Accordingly, we do not own any net wells.

Drilling Results

As a holder of mineral interests, we generally are not provided with information as to whether any wells drilled on the acreage associated with our mineral interests are classified as exploratory or as developmental wells. We are not aware of any dry holes drilled on the acreage associated with our mineral interests during the relevant period.

ITEM 3. LEGAL PROCEEDINGS

From time to time we are party to litigation matters incidental to the conduct of our business. It is the opinion of management that the ultimate resolution of our pending litigation matters will not have a material adverse effect on our financial condition, results of operation or liquidity. However, we cannot assure you that disputes or litigation will not arise or that we will be able to resolve any such future disputes or litigation in a satisfactory manner. The information under "General Litigation" and "Other" in "Item 8. Financial Statements and Supplementary Data—Note 21 – Commitments and Contingencies" is incorporated herein by this reference.

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 (17 CFR 229.104) is included in Exhibit 95.1 to this Annual Report on Form 10-K.

PART II

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

The common units representing limited partners' interests are listed on the NASDAQ Global Select Market under the symbol "ARLP." The common units began trading on August 20, 1999. There were approximately 40,809 record holders of common units at December 31, 2019.

We distribute to our partners, on a quarterly basis, all of our available cash. "Available cash," as defined in our partnership agreement, generally means, with respect to any quarter, all cash on hand at the end of each quarter, plus working capital borrowings after the end of the quarter, less cash reserves in the amount necessary or appropriate in the reasonable discretion of our general partner to (a) provide for the proper conduct of our business, (b) comply with applicable law or any debt instrument or other agreement of ours or any of our affiliates, and (c) provide funds for distributions to unitholders for any one or more of the next four quarters. Prior to the Exchange Transaction, if quarterly distributions of available cash exceeded certain target distribution levels, MGP received distributions based on specified increasing percentages of the available cash that exceeded the target distribution levels. The target distribution levels were based on the amounts of available cash from our operating surplus distributed for a quarter that exceeded the minimum quarterly distribution ("MQD") and common unit arrearages, if any. The MQD was defined as $0.125 per unit for each full fiscal quarter ($0.50 per unit on an annual basis).

Under the quarterly incentive distribution provisions of the partnership agreement prior to the Exchange Transaction, MGP was entitled to receive 15% of the amount we distributed in excess of $0.1375 per unit, 25% of the amount we distributed in excess of $0.15625 per unit, and 50% of the amount we distributed in excess of $0.1875 per unit. Beginning with distributions declared for the three months ended June 30, 2017, payable in August 2017, we no longer make distributions with respect to IDRs.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" contained herein.

Unit Repurchase Program

On May 31, 2018, ARLP announced that the Board of Directors approved the establishment of a unit repurchase program authorizing ARLP to repurchase up to $100 million of its outstanding limited partner common units. The unit repurchase program is intended to enhance ARLP's ability to achieve its goal of creating long-term value for its unitholders and provides another means, along with quarterly cash distributions, of returning cash to unitholders. The program has no time limit and ARLP may repurchase units from time to time in the open market or in other privately negotiated transactions. The unit repurchase program authorization does not obligate ARLP to repurchase any dollar amount or number of units, and repurchases may be commenced or suspended from time to time without prior notice.

The table below represents all unit repurchases for the three months ended December 31, 2019:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Program	Maximum Dollar Value that May Yet Be Used to Repurchase Units Under the Publicly Announced Program
				(in thousands)
November 1 through November 30, 2019	1,475,594	$ 11.96	1,475,594	$ 6,511

Since inception of the unit repurchase program, we have repurchased and retired 5,460,604 units at an average unit price of $17.12 for an aggregate purchase price of $93.5 million as of December 31, 2019. The remaining authorized amount for unit repurchases under this program was $6.5 million.

ITEM 6. SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2019, 2018, 2017, 2016 and 2015.

(in millions, except unit, per unit, per ton data and per BOE data)

	Year Ended December 31,				
	2019	2018	2017	2016	2015
Statements of Income					
Sales and operating revenues:					
Coal sales	$ 1,762.4	$ 1,844.8	$ 1,711.1	$ 1,861.8	$ 2,158.0
Oil & gas royalties	51.7	—	—	—	—
Transportation revenues	99.5	112.4	41.7	30.1	33.6
Other revenues	48.1	45.7	43.4	39.6	82.1
Total revenues	1,961.7	2,002.9	1,796.2	1,931.5	2,273.7
Expenses:					
Operating expenses (excluding depreciation, depletion and amortization)	1,182.0	1,207.7	1,091.9	1,122.7	1,386.8
Transportation expenses	99.5	112.4	41.7	30.1	33.6
Outside coal purchases	23.4	1.5	—	1.5	0.3
General and administrative	73.0	68.3	61.8	72.6	67.5
Depreciation, depletion and amortization	309.1	280.2	269.0	336.5	324.0
Settlement gain	—	(80.0)	—	—	—
Asset impairment	15.2	40.5	—	—	100.1
Total operating expenses	1,702.2	1,630.6	1,464.4	1,563.4	1,912.3
Income from operations	259.5	372.3	331.8	368.1	361.4
Interest expense (net of interest capitalized)	(45.9)	(40.2)	(39.4)	(30.7)	(31.2)
Interest income	0.4	0.2	0.1	—	1.5
Equity method investment income (loss)	2.2	22.2	13.9	3.5	(49.0)
Equity securities income	12.9	15.7	6.4	—	—
Acquisition gain	177.0	—	—	—	22.5
Debt extinguishment loss	—	—	(8.1)	—	—
Other income (expense)	0.6	(2.6)	(0.3)	(1.4)	1.0
Income before income taxes	406.7	367.5	304.4	339.5	306.2
Income tax expense (benefit)	(0.2)	0.0	0.2	—	—
Net income	406.9	367.5	304.2	339.5	306.2
Less: Net income attributable to noncontrolling interest	(7.5)	(0.9)	(0.6)	(0.1)	—
Net income attributable to ARLP	$ 399.4	$ 366.6	$ 303.6	$ 339.4	$ 306.2
Net income attributable to ARLP					
General Partners (1)	$ —	$ 1.6	$ 21.9	$ 80.9	$ 146.3
Limited Partners	$ 399.4	$ 365.0	$ 281.7	$ 258.5	$ 159.9
Earnings per limited partner unit-basic and diluted (2) (3)	$ 3.07	$ 2.74	$ 2.80	$ 3.39	$ 2.11
Pro forma earnings per limited partner unit-basic and diluted (2) (4)	$ 3.07	$ 2.73	$ 2.25	$ 2.51	$ 2.28
Distributions paid per limited partner unit	$ 2.15	$ 2.07	$ 1.88	$ 1.9875	$ 2.6625
Weighted-average number of units outstanding-basic and diluted	128,116,670	130,758,169	98,707,696	74,354,162	74,174,389
Balance Sheet Data:					
Working capital (5)	$ 124.0	$ 169.8	$ (8.0)	$ (50.2)	$ (108.2)
Total assets	2,586.7	2,394.7	2,219.4	2,193.0	2,361.3
Long-term obligations (6)	784.7	574.6	473.0	485.0	658.6
Total liabilities	1,321.3	1,207.0	1,067.9	1,099.6	1,372.0
Partners' capital	$ 1,265.4	$ 1,187.7	$ 1,151.5	$ 1,093.4	$ 989.3
Other Operating Data:					
Tons sold	39.3	40.4	37.8	36.7	40.2
Tons produced	40.0	40.3	37.6	35.2	41.2
Coal sales per ton sold (7)	$ 44.86	$ 45.64	$ 45.24	$ 50.76	$ 53.62
Cost per ton sold (8)	$ 30.68	$ 29.91	$ 28.87	$ 30.65	$ 34.46
Oil & gas BOE sold	1.61	—	—	—	—
Average sales price per BOE (9)	$ 32.12	$ —	$ —	$ —	$ —
Other Financial Data:					
Net cash provided by operating activities	$ 514.9	$ 694.3	$ 556.1	$ 703.5	$ 716.3
Net cash used in investing activities	(488.1)	(245.2)	(244.8)	(191.8)	(355.9)
Net cash used in financing activities	(234.4)	(211.7)	(344.4)	(505.4)	(351.6)
EBITDA (10)	753.8	686.9	612.1	706.6	659.9
Adjusted EBITDA (10)	599.0	647.4	620.3	706.6	737.5
Maintenance capital expenditures (11)	$ 260.3	$ 222.4	$ 140.0	$ 93.3	$ 236.3

(1) Amounts for 2018 reflect the impact of the Simplification Transactions which ended net income allocations and quarterly cash distributions to MGP after May 31, 2018. Amounts for 2017 reflect the impact of the Exchange Transaction ending distributions that would have been paid for the IDRs and a 0.99% general partner interest in ARLP, both of which were held by MGP prior to the Exchange Transaction. For the time period between the Exchange Transaction and the Simplification Transactions, MGP maintained a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal and thus received quarterly distributions and income and loss allocations during this time period. See "Item 8. Financial Statements and Supplementary Data—Note 14 – Earnings Per Limited Partner Unit" for more information.

(2) Diluted earnings per unit ("EPU") gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive units calculated under the treasury stock method if their effect is anti-dilutive. For the years ended December 31, 2019, 2018, 2017, 2016 and 2015, long-term incentive plan ("LTIP"), Supplemental Executive Retirement Plan ("SERP") and Directors' compensation units of 1,284,013, 1,658,908 1,466,404, 922,386 and 734,171, respectively, were considered anti-dilutive.

(3) As a result of the Exchange Transaction, net income beginning with the second quarter of 2017 was not allocated to IDRs and the related general partner interests exchanged; however, additional net income in a corresponding amount was allocated to limited partner interests. Please read "Item 8. Financial Statements and Supplementary Data—Note 12 – Earnings Per Limited Partner Unit" for more information on the impact of the Exchange Transaction on basic and diluted earnings per limited partner unit.

(4) On a pro forma basis, as if the Exchange Transaction and the Simplification Transactions had taken place on January 1, 2015, the reconciliation of net income attributable to ARLP to basic and diluted earnings per unit and the weighted-average units used in computing EPU are as follows:

	Year Ended December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
	(in thousands, except per unit data)				
Net income attributable to ARLP	$ 399,414	$ 366,604	$ 303,638	$ 339,398	$ 306,198
Pro forma adjustments (a)	—	(1,265)	(1,943)	(2,985)	(2,013)
Pro forma net income attributable to ARLP	399,414	365,339	301,695	336,413	304,185
Less:					
Distributions to participating securities	(4,254)	(5,114)	(4,339)	(3,391)	(3,493)
Undistributed earnings attributable to participating securities	(2,237)	(1,627)	(680)	(1,548)	—
Net income attributable to ARLP available to limited partners (b)	$ 392,923	$ 358,598	$ 296,676	$ 331,474	$ 300,692
Weighted-average limited partner units outstanding – basic and diluted (b)	128,117	131,310	132,024	131,805	131,625
Pro forma earnings per limited partner unit - basic and diluted	$ 3.07	$ 2.73	$ 2.25	$ 2.51	$ 2.28

(a) Pro forma adjustments to the net income attributable to ARLP primarily represent the elimination of administrative service revenues from AHGP and the inclusion of general and administrative expenses incurred at AHGP.
(b) Net income attributable to ARLP available to limited partners reflects net income allocations made for all periods presented based on the ownership structure subsequent to the Simplification Transactions. Accordingly, no general partner income allocations are presented above. Pro forma amounts above also reflect weighted average units outstanding as if the issuance of 56,128,141 ARLP common units in the Exchange Transaction and 1,322,388 ARLP common units in the Simplification Transactions applied to all periods presented.

(5) Working capital is impacted by current maturities of long-term debt. For information regarding long-term debt, please read "Item 8. Financial Statements and Supplementary Data—Note 7 – Long-Term Debt."

(6) Long-term obligations include long-term portions of debt, finance and operating lease obligations.

(7) Coal sales per ton sold are based on total coal sales divided by tons sold.

(8) Cost per ton sold is based on the total of operating expenses excluding oil & gas related expenses and outside coal purchases divided by tons sold.

(9) Average sales price per BOE is defined as royalty revenues excluding lease bonus revenue divided by total barrels of oil equivalent. BOE for natural gas volumes is calculated on a 6:1 basis (6 Mcf of natural gas to one barrel).

(10) EBITDA and Adjusted EBITDA are financial measures not calculated in accordance with generally accepted accounting principles ("GAAP"). EBITDA is defined as net income attributable to ARLP before net interest expense, income taxes and depreciation, depletion and amortization. Adjusted EBITDA is EBITDA modified for certain items that may not reflect the trend of future results, such as asset impairments, gains and losses from acquisition-valuation related accounting, settlement gains, and debt extinguishment losses.

EBITDA is used as a supplemental financial measure by management and by external users of our financial statements such as investors, commercial banks, research analysts and others. We believe that the presentation of EBITDA provides useful information to investors regarding our performance and results of operations because EBITDA, when used in conjunction with related GAAP financial measures, (i) provides additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provides investors with the financial analytical framework upon which we base financial, operational, compensation and planning decisions and (iii) presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations.

We believe Adjusted EBITDA is a useful measure for investors because it further demonstrates the performance of our assets without regard to items that may not reflect the trend of future results.

EBITDA and Adjusted EBITDA should not be considered as alternatives to net income attributable to ARLP, net income, income from operations, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA and Adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing EBITDA and Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies, or EBITDA and Adjusted EBITDA may be computed differently by us in different contexts (e.g., public reporting versus computation under financing agreements).

The following table presents a reconciliation of (a) GAAP "Cash Flows Provided by Operating Activities" to non-GAAP Adjusted EBITDA and EBITDA and (b) non-GAAP Adjusted EBITDA and EBITDA to GAAP "Net income attributable to ARLP":

	Year Ended December 31,				
	2019	2018	2017	2016	2015
			(in thousands)		
Cash flows provided by operating activities	$ 514,895	$ 694,345	$ 556,116	$ 703,544	$ 716,342
Non-cash compensation expense	(11,934)	(12,114)	(12,326)	(13,885)	(12,631)
Asset retirement obligations	(4,087)	(3,926)	(3,793)	(3,769)	(3,192)
Coal inventory adjustment to market	(4,895)	(1,455)	(449)	—	(1,952)
Equity investment income (loss)	2,203	22,189	13,860	3,543	(49,046)
Distributions received from investments	(2,203)	(21,971)	(13,939)	(2,719)	—
Income from equity securities paid-in-kind	712	15,696	6,398	—	—
Net gain (loss) on sale of property, plant and equipment	(109)	1,285	696	76	1
Valuation allowance of deferred tax assets	413	1,560	3,339	1,365	(1,557)
Other	(5,677)	(3,171)	(6,212)	(3,300)	(6,388)
Net effect of working capital changes	53,348	(4,260)	37,640	(8,808)	66,159
Interest expense, net	45,496	40,059	39,291	30,659	29,694
Income tax expense	(211)	22	210	13	21
Settlement gain	—	(80,000)	—	—	—
Cash received on redemption of equity securities in excess of investment	11,482	—	—	—	—
Acquisition gain attributable to noncontrolling interests	7,083	—	—	—	—
Net (income) loss attributable to noncontrolling interests	(7,512)	(866)	(563)	(140)	27
Adjusted EBITDA	599,004	647,393	620,268	706,579	737,478
Settlement gain	—	80,000	—	—	—
Asset impairment	(15,190)	(40,483)	—	—	(100,130)
Acquisition gain, net	169,960	—	—	—	22,548
Debt extinguishment loss	—	—	(8,148)	—	—
EBITDA	753,774	686,910	612,120	706,579	659,896
Depreciation, depletion and amortization	(309,075)	(280,225)	(268,981)	(336,509)	(323,983)
Interest expense, net	(45,496)	(40,059)	(39,291)	(30,659)	(29,694)
Income tax expense	211	(22)	(210)	(13)	(21)
Net income attributable to ARLP	$ 399,414	$ 366,604	$ 303,638	$ 339,398	$ 306,198

(11) Our maintenance capital expenditures, as defined under the terms of our partnership agreement, are those capital expenditures required to maintain, over the long term, the operating capacity of our capital assets.

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

General

The following discussion of our financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included in Item 8. Financial Statements and Supplementary Data where you can find more detailed information in "Note 1 – Organization and Presentation" and "Note 2 – Summary of Significant Accounting Policies" regarding the basis of presentation supporting the following financial information.

Executive Overview

We are a diversified natural resource company that generates income from the production and marketing of coal to major domestic and international utilities and industrial users as well as income from oil & gas mineral interests located in strategic producing regions across the United States. We are currently the second-largest coal producer in the eastern United States with seven underground mining complexes in Illinois, Indiana, Kentucky, Maryland and West Virginia, as well as a coal-loading terminal in Indiana. In addition, the mineral interests we own are in premier oil & gas producing regions of the United States, primarily in the Permian, Anadarko and Williston Basins.

Our mining operations are located near many of the major eastern utility generating plants and on major coal hauling railroads in the eastern United States. Our River View and Tunnel Ridge mines and Mt. Vernon transloading facility are located on the Ohio River. As of December 31, 2019, we had approximately 1.69 billion tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. We believe we control adequate reserves to implement our currently contemplated mining plans. Please see "Item 1. Business—Coal Operations – Detail" for further discussion of our mines.

In 2019, we sold 39.3 million tons of coal and produced 40.0 million tons. The coal we sold in 2019 was approximately 26.2% low-sulfur coal, 65.2% medium-sulfur coal and 8.6% high-sulfur coal. Based on market expectations, we classify low-sulfur coal as coal with a sulfur content of less than 1.5%, medium-sulfur coal as coal with a sulfur content of 1.5% to 3%, and high-sulfur coal as coal with a sulfur content of greater than 3%. The Btu content of our coal ranges from 11,400 to 13,200.

During 2019, approximately 78.8% of our tons sold were purchased by United States electric utilities and 17.9% were sold into the international markets through brokered transactions. The balance of tons sold were to third-party resellers and industrial consumers. Although many utility customers continue to favor a shorter-term contracting strategy, in 2019, approximately 78.5% of our sales tonnage was sold under long-term contracts. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2019, approximately 90.9% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices.

On January 3, 2019, our subsidiary, Alliance Royalty, LLC completed the AllDale Acquisition and acquired all of the limited partner interests not owned by Cavalier Minerals in AllDale I and AllDale II and the general partner interests in AllDale I & II for $176.2 million. On February 8, 2019, our equity investment of Series A-1 Preferred Interests in Kodiak was redeemed for $135.0 million cash. On August 2, 2019, our subsidiary, AR Midland acquired certain mineral interests in the Wing Acquisition for $144.9 million. As a result of the AllDale Acquisition, the Wing Acquisition, our previous AllDale investments held through Cavalier Minerals and our investment in AllDale III, we hold approximately 55,700 net royalty acres located primarily in the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) Basins. The AllDale and Wing Acquisitions provide us with diversified exposure to industry leading operators and are consistent with our general business strategy to grow our oil & gas mineral interest business. For more information on these transactions, please read "Item 8. Financial Statement and Supplemental Data—Note 3 – Acquisitions" and "—Note 12 – Investments".

As discussed in more detail in "Item 1A. Risk Factors," our results of operations could be impacted by variability in coal sales prices in addition to prices for items that are used in coal production such as steel, electricity and other supplies, unforeseen geologic conditions or mining and processing equipment failures and unexpected maintenance problems, and by the availability or reliability of transportation for coal shipments. Moreover, the mining regulatory environment in which we operate has grown increasingly stringent as a result of legislation and initiatives pursued during previous administrations. Additionally, our results of operations could be impacted by our ability to obtain and renew permits necessary for our operations, secure or acquire coal reserves, or find replacement buyers for coal under contracts with comparable terms to existing contracts. As outlined in "Item 1. Business—Environmental, Health, and Safety Regulations," a variety of measures taken by regulatory agencies in the United States and abroad in response to the perceived threat from climate change attributed to GHG emissions could substantially increase compliance costs for us and our customers and reduce demand for fossil fuels including coal which could materially and adversely impact our results of operations.

We are dependent on third-party Operators for the exploration, development and production of our oil & gas mineral interests; therefore, the success and timing of drilling and development of our oil & gas mineral interests depend on a number of factors outside our control. Some of those factors include the Operators' capital costs for drilling, development and production activities, the Operators' ability to access capital, the Operators' selection of counterparties for the marketing and sale of production and oil & gas prices in general, among others, as outlined in "Item 1. Business—Regulation of the Oil & Gas Industry". The operations on the properties in which we hold oil & gas mineral interests are also subject to various governmental laws and regulations. Compliance with these laws and regulations could be burdensome or expensive for these Operators and could result in the Operators incurring significant liabilities, either of which could delay production and may ultimately impact the Operators' ability and willingness to develop the properties in which we hold oil & gas mineral interests.

For additional information regarding some of the risks and uncertainties that affect our business and the industries in which we operate, see "Item 1A. Risk Factors."

Our principal expenses related to the production of coal are labor and benefits, equipment, materials and supplies, maintenance, royalties and excise taxes in addition to capital required to maintain our current levels of production. We employ a totally union-free workforce. Many of the benefits of our union-free workforce are related to higher productivity and are not necessarily reflected in our direct costs. In addition, transportation costs may be substantial and are often the determining factor in a coal consumer's contracting decision. The principal expenses related to our minerals interests business are production and ad valorem taxes.

Our primary business strategy is to create sustainable, capital-efficient growth in available cash to maximize the return of cash to our unitholders by:

- expanding our operations by adding and developing mines and coal reserves in existing, adjacent or neighboring properties;
- extending the lives of our current mining operations through acquisition and development of coal reserves using our existing infrastructure;
- continuing to make productivity improvements to remain a low-cost producer in each region in which we operate;
- strengthening our position with existing and future customers by offering a broad range of coal qualities, transportation alternatives and customized services;
- developing strategic relationships to take advantage of opportunities within the coal and oil & gas industries and MLP sector; and
- continuing to make investments in oil & gas mineral interests in various geographic locations within producing basins in the continental United States.

As of December 31, 2019, we had three reportable segments: Illinois Basin, Appalachia and Minerals. We also have an "all other" category referred to as Other and Corporate. The two coal reportable segments correspond to major coal producing regions in the eastern United States with similar economic characteristics including coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues. The Minerals segment includes our oil & gas mineral interests which are located in premier oil & gas basins in the United States.

As a result of the AllDale Acquisition, we now control the underlying oil & gas mineral interests held by AllDale I & II. This control over the oil & gas mineral interests held by AllDale I & II reflects a strategic change in how we manage our business and how resources are allocated by our chief operating decision maker. Due to this strategic change, we realigned our reportable segments in the first quarter of 2019 to include our oil & gas mineral interests within a new Minerals reportable segment. The mineral interests acquired through the Wing Acquisition in August 2019 are also included within the Minerals reportable segment. As a part of our realignment, we have also included our Mt. Vernon Transfer Terminal, LLC ("Mt. Vernon") and Mid-America Carbonates, LLC ("MAC") in the Illinois Basin reportable segment rather than Other and Corporate to better reflect our Illinois Basin related activities. Prior periods have been recast to include our oil & gas mineral interests in the Minerals segment, and Mt. Vernon and MAC in the Illinois Basin segment.

- *Illinois Basin* reportable segment includes our operating mining complexes (a) Gibson County Coal's mining complex, which includes the Gibson North and Gibson South mines, (b) Warrior's mining complex, (c) River View's mining complex and (d) the Hamilton mining complex. The Illinois Basin reportable segment also includes our operating Mt. Vernon coal loading terminal in Indiana on the Ohio River. The Gibson North mine was idled in the fourth quarter of 2019 in response to market conditions.

  The Illinois Basin reportable segment also includes MAC and other support services as well as non-operating mining complexes (a) Webster County Coal's Dotiki mining complex, which ceased production in August 2019, (b) White County Coal, LLC's Pattiki mining complex, (c) the Hopkins County Coal mining complex, and (d) Sebree's mining complex.

- *Appalachia* reportable segment includes our operating mining complexes (a) the Mettiki mining complex, (b) the Tunnel Ridge mining complex and (c) the MC Mining mining complex. The Mettiki mining complex includes Mettiki Coal (WV)'s Mountain View mine and Mettiki Coal (MD)'s preparation plant. The Appalachia reportable segment also includes Penn Ridge assets, which is primarily coal mineral interests.

- *Minerals* reportable segment includes oil & gas mineral interests held by AR Midland and AllDale I & II, and includes Alliance Minerals equity interest in both AllDale III and Cavalier Minerals. AR Midland acquired its mineral interests in the Wing Acquisition.

- *Other and Corporate* marketing and administrative activities include the Matrix Group, Alliance Coal's coal brokerage activity and Alliance Minerals' prior equity investment in Kodiak. In February 2019, Kodiak redeemed our equity investment. In addition, Other and Corporate includes certain Alliance Resource Properties' land and mineral interest activities, Pontiki Coal, LLC's workers' compensation and pneumoconiosis liabilities, Wildcat Insurance, which assists the ARLP Partnership with its insurance requirements, and AROP Funding, LLC ("AROP Funding") and Alliance Resource Finance Corporation ("Alliance Finance").

How We Evaluate Our Performance

Our management uses a variety of financial and operational measurements to analyze our performance. Primary measurements include the following: (1) raw and saleable tons produced per unit shift; (2) coal sales price per ton; (3) BOE produced; (4) Price per BOE; (5) Segment Adjusted EBITDA Expense per ton; (6) EBITDA; and (7) Segment Adjusted EBITDA.

Raw and Saleable Tons Produced per Unit Shift. We review raw and saleable tons produced per unit shift as part of our operational analysis to measure the productivity of our operating segments, which is significantly influenced by mining conditions and the efficiency of our preparation plants. Our discussion of mining conditions and preparation plant costs are found below under "*—Analysis of Historical Results of Operations*" and therefore provides implicit analysis of raw and saleable tons produced per unit shift.

Coal Sales Price per Ton. We define coal sales price per ton as total coal sales divided by tons sold. We review coal sales price per ton to evaluate marketing efforts and for market demand and trend analysis.

Oil & gas BOE sold. We monitor and analyze our BOE sales volumes from the various basins that comprise our portfolio of mineral interests. We also regularly compare projected volumes to actual volumes reported and investigate unexpected variances.

Price per BOE. We define price per BOE as total oil & gas royalties divided by BOE produced. We review price per BOE to evaluate performance against budget and for trend analysis.

Segment Adjusted EBITDA Expense per Ton. We define Segment Adjusted EBITDA Expense per ton (a non-GAAP financial measure) as the sum of operating expenses, coal purchases and other expense divided by total tons sold. We review Segment Adjusted EBITDA Expense per ton for cost trends.

EBITDA. We define EBITDA (a non-GAAP financial measure) as net income attributable to ARLP before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others. We believe that the presentation of EBITDA provides useful information to investors regarding our performance and results of operations because EBITDA, when used in conjunction with related GAAP financial measures, (i) provides additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provides investors with the financial analytical framework upon which we base financial, operational, compensation and planning decisions and (iii) presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations.

Segment Adjusted EBITDA. We define Segment Adjusted EBITDA (a non-GAAP financial measure) as net income attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization, general and administrative expense, settlement gain, asset impairment and acquisition gain. Management therefore is able to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments.

Analysis of Historical Results of Operations

2019 Compared with 2018

We reported net income attributable to ARLP of $399.4 million for 2019 compared to $366.6 million for 2018. The increase of $32.8 million was due to a $170.0 million non-cash net gain related to the AllDale Acquisition, reduced non-cash asset impairments, the addition of oil & gas royalty revenues and lower operating expenses benefiting 2019, partially offset by decreased coal sales revenues and increased depreciation in 2019. In addition, 2018 benefited from an $80.0 million net gain on settlement of litigation. Total revenues were $1.96 billion in 2019 compared to $2.00 billion for 2018, primarily due to lower coal sales revenues resulting from reduced coal sales volumes and prices, partially offset by the addition of oil & gas royalty revenues in 2019.

	Year Ended December 31,		Year Ended December 31,	
	2019	2018	2019	2018
	(in thousands)		(per ton sold)	
Tons sold	39,289	40,421	N/A	N/A
Tons produced	39,981	40,266	N/A	N/A
Coal sales	$ 1,762,442	$ 1,844,808	$ 44.86	$ 45.64
Oil & gas royalties	$ 51,735	$ —	N/A	N/A
Coal - Segment Adjusted EBITDA Expense (1) (2)	$ 1,197,085	$ 1,211,800	$ 30.47	$ 29.98

(1) For a definition of Segment Adjusted EBITDA Expense and related reconciliation to its comparable GAAP financial measure, please see below under "—Reconciliation of non-GAAP "Segment Adjusted EBITDA Expense" to GAAP "Operating Expenses."
(2) Coal - Segment Adjusted EBITDA Expense is defined as consolidated Segment Adjusted EBITDA Expense excluding our Minerals segment.

Coal sales. Coal sales decreased $82.4 million or 4.5% to $1.76 billion for 2019 from $1.84 billion for 2018. The decrease in coal sales was attributable to a volume variance of $51.7 million resulting from reduced tons sold and a price variance of $30.7 million due to lower average coal sales prices. Coal sales volumes declined 2.8% to 39.3 million tons due primarily to lower export sales, partially offset by increased coal sales to domestic customers. Weak coal market conditions also impacted price realizations which declined 1.7% in 2019 to $44.86 per ton sold, compared to $45.64 per ton sold during 2018.

Oil & gas royalties. Our mineral interests contributed oil & gas royalties of $51.7 million in 2019. Please read "Item 8. Financial Statements and Supplementary Data—Note 3 – Acquisitions" for more information on the AllDale and Wing Acquisitions.

Coal - Segment Adjusted EBITDA Expense. Segment Adjusted EBITDA Expense, excluding our Minerals segment, decreased 1.2% to $1.20 billion for 2019 from $1.21 billion for 2018 primarily due to reduced coal sales volumes offset in part by increased expenses per ton. Segment Adjusted EBITDA Expense per ton, excluding our Minerals segment, increased to $30.47 per ton sold compared to $29.98 per ton sold in 2018 due to curtailed production at our Gibson South mine, reduced longwall shifts at our Hamilton mine and lower recoveries at our River View and Mettiki mines, offset in part by increased recoveries from our Tunnel Ridge and Warrior mines and fewer longwall move days at Tunnel Ridge in 2019. In addition, other cost increases are discussed by category below:

- Labor and benefit expenses per ton produced, excluding workers' compensation, increased 6.2% to $9.89 per ton in 2019 from $9.31 per ton in 2018. This increase of $0.58 per ton was primarily attributable to reduced sales and production volumes;

- Workers' compensation expenses per ton produced increased to $0.50 per ton in 2019 from $0.34 per ton in 2018. The increase of $0.16 per ton produced resulted from the impact of lower discount rates and higher actuarial accrual adjustments due primarily to unfavorable changes in claims development;

- Maintenance expenses per ton produced increased 4.1% to $3.59 per ton in 2019 from $3.45 per ton in 2018. The increase of $0.14 per ton produced was primarily due to reduced sales and production volumes at certain mines discussed above; and

- Outside coal purchases increased $21.9 million in 2019 as a result of sales from purchased coal, which generally cost higher on a per ton basis than our produced coal.

Segment Adjusted EBITDA Expense increases above were partially offset by the following decrease:

- Production taxes, royalties and other selling expenses are primarily based on coal volumes and a percentage of coal sales prices. These expenses decreased $0.67 per produced ton sold in 2019 compared to 2018 primarily due to a favorable state sales mix and lower excise tax rates in 2019.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $309.1 million for 2019 compared to $280.2 million for 2018 primarily as a result of depletion from production of our oil & gas royalty interests in 2019.

Settlement gain. During 2018, we finalized an agreement with a customer and certain of its affiliates to settle litigation we initiated in 2015. The agreement provided for a $93.0 million cash payment to us in 2018, future conditional coal supply commitments, continued export transloading capacity for our Appalachian mines and the acquisition of certain coal reserves near our Tunnel Ridge operation. A settlement gain of $80.0 million was recorded in 2018 reflecting the cash payment received net of $13.0 million of combined legal fees paid and associated incentive compensation accruals.

Asset impairment. We recognized a non-cash asset impairment charge of $15.2 million at our Dotiki mine in 2019 as we ceased operations to shift production to our lower cost mines. In 2018, we recognized $40.5 million of non-cash impairment charges, comprised of a $34.3 million impairment related to the reduction of economic life at our Dotiki mine and a $6.2 million impairment due to a decrease in fair value of an option entitling us to lease certain coal reserves in Illinois.

Equity method investment income. Equity method investment income decreased to $2.2 million in 2019 from $22.2 million in 2018 due to the elimination of this income from AllDale I & II for all of 2019 offset in part by the increase of income from our AllDale III investment. The elimination of equity method investment income from AllDale I & II was due to the AllDale Acquisition and resulting consolidation of AllDale I & II on our consolidated statements of income beginning in January 2019. Prior to 2019, our investments in AllDale I & II generated income in addition to AllDale III.

Acquisition gain. We were required to re-measure Cavalier Minerals' equity method investments in AllDale I & II to fair value as a result of the AllDale Acquisition. The re-measurement resulted in a gain of $177.0 million in 2019. Please read ""Item 8. Financial Statements and Supplementary Data—Note 3 – Acquisitions" for more information on the acquisition gain in connection with the AllDale Acquisition.

Transportation revenues and expenses. Transportation revenues and expenses were $99.5 million and $112.4 million for 2019 and 2018, respectively. The decrease of $12.9 million was primarily attributable to decreased coal tonnage for which we arrange third-party transportation at certain mines resulting from reduced export shipments, offset in part by an increase in average third-party transportation rates in 2019 resulting from higher shipping costs for coal exported to international markets. Transportation revenues are recognized in an amount equal to transportation expenses when title to the coal passes to the customer.

Net income attributable to noncontrolling interest. Net income attributable to noncontrolling interest increased to $7.5 million in 2019 from $0.9 million in 2018 due to allocating $7.1 million of the AllDale Acquisition gain discussed above, to noncontrolling interest related to Bluegrass Minerals Management, LLC's ("Bluegrass Minerals") equity interest in Cavalier Minerals.

Segment Information. Our 2019 Segment Adjusted EBITDA decreased $43.7 million, or 6.1%, to $672.0 million from 2018 Segment Adjusted EBITDA of $715.7 million. Segment Adjusted EBITDA, tons sold, coal sales, other revenues, oil & gas royalties, BOE volumes and Segment Adjusted EBITDA Expense by segment are as follows:

	Year Ended December 31, 2019	2018	Increase (Decrease)	
	(in thousands)			
Segment Adjusted EBITDA				
Coal - Illinois Basin	$ 385,200	$ 417,773	$ (32,573)	(7.8)%
Coal - Appalachia	215,950	240,286	(24,336)	(10.1)%
Minerals	46,997	21,323	25,674	120.4 %
Other and Corporate	32,911	44,864	(11,953)	(26.6)%
Elimination	(9,057)	(8,555)	(502)	(5.9)%
Total Segment Adjusted EBITDA (2)	$ 672,001	$ 715,691	$ (43,690)	(6.1)%
Tons sold				
Coal - Illinois Basin	28,480	30,055	(1,575)	(5.2)%
Coal - Appalachia	10,809	10,364	445	4.3 %
Other and Corporate	564	994	(430)	(43.3)%
Elimination	(564)	(992)	428	43.1 %
Total tons sold	39,289	40,421	(1,132)	(2.8)%
Coal sales				
Coal - Illinois Basin	$ 1,128,588	$ 1,197,143	$ (68,555)	(5.7)%
Coal - Appalachia	628,406	635,530	(7,124)	(1.1)%
Other and Corporate	22,138	43,393	(21,255)	(49.0)%
Elimination	(16,690)	(31,258)	14,568	46.6 %
Total coal sales	$ 1,762,442	$ 1,844,808	$ (82,366)	(4.5)%
Other revenues				
Coal - Illinois Basin	$ 13,034	$ 16,999	$ (3,965)	(23.3)%
Coal - Appalachia	11,166	3,000	8,166	(1)
Minerals	1,301	—	1,301	(1)
Other and Corporate	34,712	38,096	(3,384)	(8.9)%
Elimination	(12,173)	(12,431)	258	2.1 %
Total other revenues	$ 48,040	$ 45,664	$ 2,376	5.2 %
BOE volume and oil & gas royalties				
Volume - BOE (3)	1,611	—	1,611	(1)
Oil & gas royalties	$ 51,735	$ —	$ 51,735	(1)
Segment Adjusted EBITDA Expense				
Coal - Illinois Basin	$ 756,423	$ 796,370	$ (39,947)	(5.0)%
Coal - Appalachia	423,623	398,243	25,380	6.4 %
Minerals	7,811	—	7,811	(1)
Other and Corporate	36,845	52,321	(15,476)	(29.6)%
Elimination	(19,806)	(35,134)	15,328	43.6 %
Total Segment Adjusted EBITDA Expense	$ 1,204,896	$ 1,211,800	$ (6,904)	(0.6)%

(1) Percentage change not meaningful.
(2) For a definition of Segment Adjusted EBITDA and related reconciliation to its comparable GAAP financial measure, please see below under "—Reconciliation of non-GAAP "Segment Adjusted EBITDA" to GAAP "net income."
(3) BOE for natural gas is calculated on a 6:1 basis (6,000 cubic feet of natural gas to one barrel).

Illinois Basin – Segment Adjusted EBITDA decreased 7.8% to $385.2 million in 2019 from $417.8 million in 2018. The decrease of $32.6 million was primarily attributable to lower coal sales volumes, partially offset by reduced operating expenses. Tons sold in 2019 decreased 5.2% compared to 2018 resulting from lower export sales from several mines and the cessation of production at our Dotiki mine in 2019 to focus on shifting production to our lower-cost mines, offset in part by additional production units at the River View mine. Segment Adjusted EBITDA Expense decreased 5.0% to $756.4 million in 2019 from $796.4 million in 2018 due to reduced coal sales volumes. Segment Adjusted EBITDA Expense per ton increased slightly to $26.56 per ton sold in 2019 due to certain cost increases described above under "–Coal - Segment Adjusted EBITDA Expense."

Appalachia – Segment Adjusted EBITDA decreased 10.1% to $216.0 million for 2019 from $240.3 million in 2018. The decrease of $24.3 million was primarily attributable to reduced coal sales prices and increased operating expenses, partially offset by higher coal sales volumes. Coal sales, which decreased 1.1% to $628.4 million in 2019 from $635.5 million in 2018, resulted from lower coal sales prices of $58.14 per ton in 2019 compared to $61.32 per ton in 2018, partially offset by higher coal sales volumes. A strong performance at our Tunnel Ridge longwall operation increased coal sales volumes by 4.3% to 10.8 million tons sold in 2019 compared to 10.4 million tons sold in 2018. Segment Adjusted EBITDA Expense increased 6.4% to $423.6 million in 2019 from $398.2 million in 2018 due to increased sales volumes and higher expenses per ton. Segment Adjusted EBITDA Expense per ton increased 2.0% to $39.19 per ton compared to $38.43 per ton sold in 2018 reflecting lower recoveries at our Mettiki mine as well as certain cost increases described above under "–Coal - Segment Adjusted EBITDA Expense," offset in part by increased recoveries and fewer longwall move days from our Tunnel Ridge mine in 2019.

Minerals - Segment Adjusted EBITDA increased to $47.0 million for 2019 from $21.3 million in 2018. The increase of $25.7 million primarily resulted from the AllDale and Wing Acquisitions in 2019. Prior to the acquisitions, income from our equity method investments in AllDale I & II were reflected as equity method investment income. As a result of the AllDale Acquisition, we began consolidating AllDale I & II on our consolidated statements of income.

Other and Corporate – Segment Adjusted EBITDA decreased by $12.0 million to $32.9 million in 2019 compared to $44.9 million in 2018. The decrease was primarily attributable to reduced coal brokerage activity and mining technology product sales from the Matrix Group.

2018 Compared with 2017

We reported net income attributable to ARLP of $366.6 million for 2018 compared to $303.6 million for 2017. The increase of $63.0 million was due to record coal sales volumes, which rose to 40.4 million tons sold in 2018 compared to 37.8 million tons sold in 2017, an $80.0 million net gain on settlement of litigation and higher investment income in 2018 and a debt extinguishment loss of $8.1 million in 2017, offset in part by increased operating expenses, transportation expenses and depreciation, depletion and amortization and the impact of a $40.5 million non-cash asset impairment charge in 2018. Increased coal sales volumes drove total revenues higher by 11.5% to $2.00 billion in 2018 compared to $1.80 billion in 2017 and drove operating expenses higher to $1.21 billion in 2018 compared to $1.09 billion in 2017.

EPU for 2018 reflects the impact of the Simplification Transactions eliminating general partner net income allocations to MGP beginning with the second quarter of 2018. EPU for 2017 reflects the impact of the Exchange Transaction eliminating general partner net income allocations associated with the IDRs and a 0.99% general partner interest in ARLP, both of which were held by MGP prior to the Exchange Transaction. MGP exchanged both its general partner interest and IDRs for a non-economic general partner interest and significant limited partner units beginning with distributions for the second quarter of 2017. See "Item 1. Business—Partnership Simplification" for more information on the Exchange Transaction and Simplification Transactions. For the time between the Exchange Transaction and the Simplification Transactions, MGP maintained a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal and thus was allocated income and loss in our calculation of EPU. We reported EPU of $2.74 in 2018 compared to $2.80 in 2017. On a pro forma basis, as if the Exchange Transaction and Simplification Transactions had taken place on January 1, 2017, basic and diluted net income of ARLP per limited partner unit ("Pro Forma EPU") in 2018 would have been $2.73 compared to $2.25 in 2017. Please read "Item 8. Financial Statements and Supplementary Data—Note 14 – Net Income of ARLP Per Limited Partner Unit" for more information on the impact of the Exchange Transaction and Simplification Transactions on EPU, including a table providing a reconciliation of Pro Forma EPU amounts to net income of ARLP.

	Year Ended December 31,		Year Ended December 31,	
	2018	2017	2018	2017
	(in thousands)		(per ton sold)	
Tons sold	40,421	37,824	N/A	N/A
Tons produced	40,266	37,609	N/A	N/A
Coal sales	$ 1,844,808	$ 1,711,114	$ 45.64	$ 45.24
Coal - Segment Adjusted EBITDA Expense (1) (2)	$ 1,211,800	$ 1,092,187	$ 29.98	$ 28.88

(1) For a definition of Segment Adjusted EBITDA Expense and related reconciliation to its comparable GAAP financial measure, please see below under "—Reconciliation of non-GAAP "Segment Adjusted EBITDA Expense" to GAAP "Operating Expenses."
(2) Coal - Segment Adjusted EBITDA Expense is defined as consolidated Segment Adjusted EBITDA Expense excluding our Minerals segment.

Coal sales. Coal sales increased $133.7 million or 7.8% to $1.84 billion for 2018 from $1.71 billion for 2017. The increase in coal sales was attributable to a volume variance of $117.5 million resulting from increased tons sold and a price variance of $16.2 million due to higher average coal sales prices. For 2018, strong performances at River View and our Gibson Complex mines, which include the resumption of operations at Gibson North in 2018, drove total coal sales volumes up 6.9% to a record 40.4 million tons and production volumes higher by 7.1% to 40.3 million tons compared to 2017.

Coal - Segment Adjusted EBITDA Expense. Segment Adjusted EBITDA Expense, excluding our Minerals segment, increased 11.0% to $1.21 billion for 2018 from $1.09 billion for 2017 primarily as a result of increased coal sales volumes. On a per ton basis, Segment Adjusted EBITDA Expense increased 3.8% to $29.98 per ton sold from $28.88 per ton sold in 2017, due primarily to difficult mining conditions encountered at several mines and additional longwall move days at our Tunnel Ridge mine in 2018. The most significant operating expense variances by category are discussed below:

- Labor and benefit expenses per ton produced, excluding workers' compensation, increased 1.6% to $9.31 per ton in 2018 from $9.16 per ton in 2017. This increase of $0.15 per ton was primarily attributable to increased labor expenses at various mines; and

- Material and supplies expenses per ton produced increased 13.1% to $11.04 per ton in 2018 from $9.76 per ton in 2017. The increase of $1.28 per ton produced resulted primarily from increases of $0.47 per ton for roof support, $0.29 per ton for contract labor used in the mining process and $0.11 per ton for power and fuel used in the mining process.

Segment Adjusted EBITDA Expense per ton increases discussed above were partially offset by the following decrease:

- Production taxes, royalties and other selling expenses incurred as a percentage of coal sales prices and volumes decreased $0.12 per produced ton sold in 2018 compared to 2017 primarily as a result of a favorable state sales mix, increased sales into the export market and lower average coal sales prices in the Illinois Basin region partially offset by higher average coal sales prices in Appalachia.

General and administrative. General and administrative expenses for 2018 increased to $68.3 million compared to $61.8 million in 2017. The increase of $6.5 million was primarily due to higher incentive compensation expenses and other professional services.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $280.2 million for 2018 compared to $269.0 million for 2017 primarily as a result of the previously discussed increase in coal sales volumes.

Settlement gain. During 2018, we finalized an agreement with a customer and certain of its affiliates to settle litigation we initiated in 2015. The agreement provided for a $93.0 million cash payment to us in 2018, future conditional coal supply commitments, continued export transloading capacity for our Appalachian mines and the acquisition of certain coal reserves near our Tunnel Ridge operation. A settlement gain of $80.0 million was recorded in 2018 reflecting the cash payment received net of $13.0 million of combined legal fees paid and associated incentive compensation accruals.

Asset impairment. We recognized $40.5 million of non-cash impairment charges in 2018, comprised of a $34.3 million impairment related to the reduction of the economic mine life at our Dotiki mine and a $6.2 million impairment as a result of a decrease in the fair value of an option entitling us to lease certain coal reserves in Illinois.

Equity method investment income. Equity method investment income increased to $22.2 million in 2018 from $13.9 million in 2017 due to increased income from AllDale I, II and III, collectively referred to as the "AllDale Partnerships".

Equity securities income. Equity securities income increased $9.3 million to $15.7 million in 2018 compared to $6.4 million in 2017 due to increased distributions of preferred interests from our Kodiak investment.

Debt extinguishment loss. We recognized a debt extinguishment loss of $8.1 million in 2017 to reflect a make-whole payment incurred to repay our Series B Senior Notes in May 2017.

Transportation revenues and expenses. Transportation revenues and expenses were $112.4 million and $41.7 million for 2018 and 2017, respectively. The increase of $70.7 million was primarily attributable to increased tonnage for which we arrange third-party transportation at certain mines and an increase in average third-party transportation rates in 2018 both primarily due to increased export shipments. Transportation revenues are recognized in an amount equal to transportation expenses when title to the coal passes to the customer.

Segment Information. Our 2018 Segment Adjusted EBITDA increased 4.9% to $715.7 million from 2017 Segment Adjusted EBITDA of $682.0 million. Segment Adjusted EBITDA, tons sold, coal sales, other revenues and Segment Adjusted EBITDA Expense by segment are as follows:

	Year Ended December 31,			
	2018	**2017**	**Increase (Decrease)**	
		(in thousands)		
Segment Adjusted EBITDA				
Coal - Illinois Basin	$ 417,773	$ 398,080	$ 19,693	4.9 %
Coal - Appalachia	240,286	234,124	6,162	2.6 %
Minerals	21,323	13,297	8,026	60.4 %
Other and Corporate	44,864	45,296	(432)	(1.0)%
Elimination	(8,555)	(8,769)	214	2.4 %
Total Segment Adjusted EBITDA (1)	$ 715,691	$ 682,028	$ 33,663	4.9 %
Tons sold				
Coal - Illinois Basin	30,055	27,026	3,029	11.2 %
Coal - Appalachia	10,364	10,783	(419)	(3.9)%
Other and Corporate	994	1,636	(642)	(39.2)%
Elimination	(992)	(1,621)	629	38.8 %
Total tons sold	40,421	37,824	2,597	6.9 %
Coal sales				
Coal - Illinois Basin	$ 1,197,143	$ 1,078,255	$ 118,888	11.0 %
Coal - Appalachia	635,530	616,305	19,225	3.1 %
Other and Corporate	43,393	74,973	(31,580)	(42.1)%
Elimination	(31,258)	(58,419)	27,161	46.5 %
Total coal sales	$ 1,844,808	$ 1,711,114	$ 133,694	7.8 %
Other revenues				
Coal - Illinois Basin	$ 16,999	$ 12,024	$ 4,975	41.4 %
Coal - Appalachia	3,000	3,621	(621)	(17.1)%
Other and Corporate	38,096	39,776	(1,680)	(4.2)%
Elimination	(12,431)	(12,015)	(416)	(3.5)%
Total other revenues	$ 45,664	$ 43,406	$ 2,258	5.2 %
Segment Adjusted EBITDA Expense				
Coal - Illinois Basin	$ 796,370	$ 692,199	$ 104,171	15.0 %
Coal - Appalachia	398,243	385,802	12,441	3.2 %
Other and Corporate	52,321	75,851	(23,530)	(31.0)%
Elimination	(35,134)	(61,665)	26,531	43.0 %
Total Segment Adjusted EBITDA Expense	$ 1,211,800	$ 1,092,187	$ 119,613	11.0 %

(1) For a definition of Segment Adjusted EBITDA and related reconciliation to its comparable GAAP financial measure, please see below under "—Reconciliation of non-GAAP "Segment Adjusted EBITDA" to GAAP "net income."

Illinois Basin – Segment Adjusted EBITDA increased 4.9% to $417.8 million in 2018 from $398.1 million in 2017. The increase of $19.7 million was primarily attributable to higher coal sales, which increased 11.0% to $1.20 billion in 2018 from $1.08 billion in 2017, partially offset by increased operating expenses. The increase of $118.9 million in coal sales reflects higher coal sales volumes of 30.1 million tons sold in 2018 compared to 27.0 million tons sold in 2017, partially offset by lower average coal sales prices in 2018. The increase in coal sales volumes resulted from strong performances at our River View and Gibson Complex mines, which included the resumption of operations at Gibson North in 2018, due in part to increased export volumes. Segment Adjusted EBITDA Expense increased 15.0% to $796.4 million in 2018 from $692.2 million in 2017 due to increased sales volumes and higher expenses per ton. Segment Adjusted EBITDA Expense per ton increased $0.89 per ton sold to $26.50 from $25.61 per ton sold in 2017, primarily due to the previously mentioned difficult mining conditions in addition to increased roof support and contract labor costs per ton at various mines and start-up costs associated with reopening the Gibson North mine in 2018.

Appalachia – Segment Adjusted EBITDA increased 2.6% to $240.3 million for 2018 from $234.1 million in 2017. The increase of $6.2 million was primarily attributable to higher coal sales, which increased 3.1% to $635.5 million in 2018 from $616.3 million in 2017 partially offset by increased operating expenses. The increase of $19.2 million in coal sales reflects higher average coal sales prices of $61.32 per ton in 2018 compared to $57.16 per ton in 2017 due to increased export sales of higher priced metallurgical coal at our Mettiki mine and improved prices at our MC Mining and Tunnel Ridge mines. The price benefit was offset partially by lower coal sales volumes of 10.4 million tons sold in 2018 compared to 10.8 million tons in 2017 due to decreased volumes at our Tunnel Ridge and MC Mining mines. Segment Adjusted EBITDA Expense increased 3.2% to $398.2 million in 2018 from $385.8 million in 2017 and Segment Adjusted EBITDA Expense per ton increased $2.65 per ton sold to $38.43 compared to $35.78 per ton sold in 2017. The increase was primarily due to difficult mining conditions and additional longwall move days at our Tunnel Ridge mine and an increased sales mix of higher-cost Mettiki coal production in 2018 as well as certain cost increases described above under "–Operating expenses and outside coal purchases."

Minerals - Segment Adjusted EBITDA increased to $21.3 million for 2019 from $13.3 million in 2018. The increase of $8.0 million resulted from higher equity income from the AllDale Partnerships in 2018.

Other and Corporate – Coal sales and Segment Adjusted EBITDA Expense decreased by $31.6 million and $23.5 million, respectively due to reduced coal brokerage activity.

Reconciliation of non-GAAP "Segment Adjusted EBITDA" to GAAP "net income" and reconciliation of non-GAAP "Segment Adjusted EBITDA Expense" to GAAP "Operating Expenses"

Segment Adjusted EBITDA (a non-GAAP financial measure) is defined as net income attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization, settlement gain, asset impairment, acquisition gain, debt extinguishment loss and general and administrative expenses. Segment Adjusted EBITDA is a key component of consolidated EBITDA, which is used as a supplemental financial measure by management and by external users of our financial statements such as investors, commercial banks, research analysts and others. We believe that the presentation of EBITDA provides useful information to investors regarding our performance and results of operations because EBITDA, when used in conjunction with related GAAP financial measures, (i) provides additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provides investors with the financial analytical framework upon which we base financial, operational, compensation and planning decisions and (iii) presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations.

Segment Adjusted EBITDA is also used as a supplemental financial measure by our management for reasons similar to those stated in the previous explanation of EBITDA. In addition, the exclusion of corporate general and administrative expenses, which are discussed above under "—Analysis of Historical Results of Operations," from consolidated Segment Adjusted EBITDA allows management to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments.

The following is a reconciliation of consolidated Segment Adjusted EBITDA to net income, the most comparable GAAP financial measure:

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Consolidated Segment Adjusted EBITDA	$ 672,001	$ 715,691	$ 682,028
General and administrative	(72,997)	(68,298)	(61,760)
Depreciation, depletion and amortization	(309,075)	(280,225)	(268,981)
Settlement gain	—	80,000	—
Asset impairment	(15,190)	(40,483)	—
Interest expense, net	(45,496)	(40,059)	(39,291)
Acquisition gain	177,043	—	—
Debt extinguishment loss	—	—	(8,148)
Income tax (expense) benefit	211	(22)	(210)
Acquisition gain attributable to noncontrolling interest	(7,083)	—	—
Net income attributable to ARLP	$ 399,414	$ 366,604	$ 303,638
Noncontrolling interest	7,512	866	563
Net income	$ 406,926	$ 367,470	$ 304,201

Segment Adjusted EBITDA Expense (a non-GAAP financial measure) includes operating expenses, coal purchases and other income (expense). Transportation expenses are excluded as these expenses are passed through to our customers and, consequently, we do not realize any gain or loss on transportation revenues. Segment Adjusted EBITDA Expense is used as a supplemental financial measure by our management to assess the operating performance of our segments. Segment Adjusted EBITDA Expense is a key component of Segment Adjusted EBITDA in addition to coal sales, royalty revenues and other revenues. The exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA Expense allows management to focus solely on the evaluation of segment operating performance as it primarily relates to our operating expenses.

The following is a reconciliation of consolidated Segment Adjusted EBITDA Expense to operating expense, the most comparable GAAP financial measure:

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Segment Adjusted EBITDA Expense	$ 1,204,896	$ 1,211,800	$ 1,092,187
Outside coal purchases	(23,357)	(1,466)	—
Other income (expense)	561	(2,621)	(332)
Operating expenses (excluding depreciation, depletion and amortization)	$ 1,182,100	$ 1,207,713	$ 1,091,855

Ongoing Acquisition Activities

Consistent with our business strategy, from time to time we engage in discussions with potential sellers regarding our possible acquisitions of certain assets and/or companies of the sellers. For more information on acquisitions, please read "Item 8. Financial Statements and Supplementary Data—Note 3 – Acquisitions" of this Annual Report on Form 10-K.

Liquidity and Capital Resources

Liquidity

We have historically satisfied our working capital requirements and funded our capital expenditures, investments and debt service obligations with cash generated from operations, cash provided by the issuance of debt or equity, borrowings under credit and securitization facilities and other financing transactions. We believe that existing cash balances, future cash flows from operations and investments, borrowings under credit facilities and cash provided from the issuance of debt or equity will be sufficient to meet our working capital requirements, capital expenditures and additional investments, debt payments, commitments and distribution payments. Nevertheless, our ability to satisfy our working capital requirements, to fund planned capital expenditures, to service our debt obligations or to pay distributions will depend upon our future operating performance and access to and cost of financing sources, which will be affected by prevailing economic conditions generally, and in both the coal and oil & gas industries specifically, as well as other financial and business factors, some of which are beyond our control. Based on our recent operating results, current cash position, current unitholder distributions, anticipated future cash flows and sources of financing that we expect to have available, we do not anticipate any constraints to our liquidity at this time. However, to the extent operating cash flow or access to and cost of financing sources are materially different than expected, future liquidity may be adversely affected. Please see "Item 1A. Risk Factors."

On August 2, 2019, we closed on the Wing Acquisition using cash on hand and borrowings under our revolving credit facility for $144.9 million. On January 3, 2019, we acquired all of the limited partner interests in AllDale I & II not owned by Cavalier Minerals and the general partner interests in AllDale I & II for $176.2 million, which was funded with cash on hand and borrowings under our revolving credit facility. On July 19, 2017, we purchased $100 million of Series A-1 Preferred Interests from Kodiak, a privately held company providing large scale, high utilization gas compression assets to customers operating primarily in the Permian Basin. This structured investment provided us with a quarterly cash or payment in kind return. On February 8, 2019, Kodiak redeemed our preferred interests for $135.0 million cash. For more information on these transactions, please read "Item 8. Financial Statements and Supplementary Data—Note 3 – Acquisitions" and "— Note 12 – Investments" of this Annual Report on Form 10-K.

In May 2018, the Board of Directors approved the establishment of a unit repurchase program authorizing us to repurchase up to $100 million of ARLP common units. The program has no time limit and we may repurchase units from time to time in the open market or in other privately negotiated transactions. The unit repurchase program authorization does not obligate us to repurchase any dollar amount or number of units. Since inception through December 31, 2019, we have purchased units for a total of $93.5 million under the program. Please read "Part II - Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities" for more information on the unit repurchase program.

Mine Development Project

In 2018, we began development of MC Mining's Excel Mine No. 5 and continued in 2019. We currently anticipate deploying capital of approximately $15.0 million to $18.0 million in 2020 to complete the project. We expect to fund the project in 2020 with cash from operations or borrowings under our credit facilities. We anticipate the new mine will enable us to access an additional 15 million tons of coal reserves with an expected mine life of approximately 12 years assuming the current level of production at MC Mining's Excel Mine No. 4 continues at the new mine. We expect the development plan for the new Excel Mine No. 5 will provide a seamless transition from the current MC Mining operation as its reserves deplete in 2020.

Cash Flows

Cash provided by operating activities was $514.9 million for 2019 compared to $694.3 million for 2018. In the comparison, 2018 benefited from $93 million received for a one-time settlement related to litigation with a customer and certain of its affiliates initiated in 2015. In addition, decreases in cash provided by operating activities for 2019 resulted from lower net income in 2019 after excluding the 2019 non-cash acquisition gain and the non-cash impairments in both years. Additional decreases in 2019 were due to unfavorable working capital changes related to inventories, accounts payable and payroll and related benefit accruals. These decreases were partially offset by a favorable working capital change related to trade receivables.

Net cash used in investing activities was $488.1 million for 2019 compared to $245.2 million for 2018. The increase in cash used in investing activities was primarily attributable to the AllDale Acquisition, the Wing Acquisition and increased capital expenditures for mine infrastructure and equipment at various mines. This increase was partially offset by cash received from Kodiak for the redemption of our equity securities in 2019, and in comparison, greater cash was used for equity method investment contributions in AllDale III in 2018.

Net cash used in financing activities was $234.4 million for 2019 compared to $211.7 million for 2018. The increase in cash used in financing activities was primarily attributable to increases in overall net payments on the securitization and revolving credit facilities and increased payments on financing lease obligations. These 2019 increases in cash used were partially offset by proceeds received for equipment financings and reduced payments for unit repurchases in 2019.

We have various commitments primarily related to long-term debt, including capital and operating leases, obligations for estimated future asset retirement obligations costs, workers' compensation and pneumoconiosis, capital projects and pension funding. We expect to fund these commitments with existing cash balances, future cash flows from operations and investments as well as cash provided from borrowings of debt or issuance of equity.

The following table provides details regarding our contractual cash obligations as of December 31, 2019:

Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
			(in thousands)		
Long-term debt	$ 789,280	$ 13,157	$ 355,051	$ 21,072	$ 400,000
Future interest obligations(1)	184,479	46,179	67,714	60,641	9,945
Operating leases	25,728	3,832	4,497	3,860	13,539
Finance leases(2)	11,268	8,747	1,824	278	419
Purchase obligations for capital projects	28,633	28,633	—	—	—
Reclamation obligations(3)	240,463	4,496	5,370	5,013	225,584
Workers' compensation and pneumoconiosis benefit(3)	303,648	11,923	18,794	15,079	257,852
Pension benefit(3)	64,614	5,288	11,722	12,849	34,755
	$ 1,648,113	$ 122,255	$ 464,972	$ 118,792	$ 942,094

(1) Interest on variable-rate, long-term debt was calculated using rates effective at December 31, 2019 for the remaining term of outstanding borrowings.

(2) Includes amounts classified as interest.

(3) Future commitments for reclamation obligations, workers' compensation and pneumoconiosis and pension are shown at undiscounted amounts. These obligations are primarily statutory, not contractual.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include coal reserve leases, indemnifications, transportation obligations and financial instruments with off-balance sheet risk, such as bank letters of credit and surety bonds. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and we do not expect these off-balance sheet arrangements to have any material adverse effects on our financial condition, results of operations or cash flows.

We use a combination of surety bonds and letters of credit to secure our financial obligations for reclamation, workers' compensation and other obligations as follows as of December 31, 2019:

	Reclamation Obligation	Workers' Compensation Obligation	Other	Total
		(in millions)		
Surety bonds	$ 181.6	$ 82.2	$ 15.8	$ 279.6
Letters of credit	—	8.0	6.3	14.3

Capital Expenditures

Capital expenditures increased to $305.9 million in 2019 compared to $233.5 million in 2018. See our discussion of "Cash Flows" above concerning the increase in capital expenditures.

We currently project average estimated annual maintenance capital expenditures over the next five years of approximately $5.04 per ton produced. Our anticipated total capital expenditures, including maintenance capital expenditures, for 2020 are estimated in a range of $165.0 million to $190.0 million. Management anticipates funding 2020 capital requirements with our December 31, 2019 cash and cash equivalents of $36.5 million, cash flows from operations and investments, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity. We will continue to have significant capital requirements over the long term, which may require us to incur debt or seek additional equity capital. The availability and cost of additional capital will depend upon prevailing market conditions, the market price of our common units and several other factors over which we have limited control, as well as our financial condition and results of operations.

Insurance

Effective October 1, 2019, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market. The maximum limit in the commercial property program is $100.0 million per occurrence, excluding a $1.5 million deductible for property damage, a 60, 75, 90 or 120 day waiting period for underground business interruption depending on the mining complex and an additional $10.0 million overall aggregate deductible. We have elected to retain a 10% participating interest in our commercial property insurance program. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future. Also, exposures exist for which no insurance may be available and for which we have not reserved. In addition, environmental activists may try to hamper fossil fuel companies by other means including pressuring insurance and surety companies into restricting access to certain needed coverages.

Debt Obligations

Credit Facility. On January 27, 2017, our Intermediate Partnership entered into a Fourth Amended and Restated Credit Agreement (the "Credit Agreement") with various financial institutions. The Credit Agreement provides for a $494.75 million revolving credit facility, including a sublimit of $125 million for the issuance of letters of credit and a sublimit of $15.0 million for swingline borrowings (the "Revolving Credit Facility"), with a termination date of May 23, 2021. We incurred debt issuance costs in 2017 of $9.2 million in connection with the Credit Agreement. These debt issuance costs are deferred and amortized as a component of interest expense over the term of the Revolving Credit Facility.

The Credit Agreement is guaranteed by all of the material direct and indirect subsidiaries of our Intermediate Partnership, and is secured by substantially all of the Intermediate Partnership's assets. Borrowings under the Revolving Credit Facility bear interest, at the option of the Intermediate Partnership, at either (i) the Base Rate at the greater of three benchmarks or (ii) a Eurodollar Rate, plus margins for (i) or (ii), as applicable, that fluctuate depending upon the ratio of Consolidated Debt to Consolidated Cash Flow (each as defined in the Credit Agreement). The Eurodollar Rate, with applicable margin, under the Revolving Credit Facility was 4.32% as of December 31, 2019. At December 31, 2019, we had $9.3 million of letters of credit outstanding with $230.5 million available for borrowing under the Revolving Credit Facility. We currently incur an annual commitment fee of 0.35% on the undrawn portion of the Revolving Credit Facility.

We utilize the Revolving Credit Facility, as appropriate, for working capital requirements, capital expenditures and investments, scheduled debt payments and distribution payments.

The Credit Agreement contains various restrictions affecting our Intermediate Partnership and its subsidiaries including, among other things, restrictions on incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates, in each case subject to various exceptions, and the payment of cash distributions by our Intermediate Partnership if such payment would result in a certain fixed charge coverage ratio (as defined in the Credit Agreement). The Credit Agreement requires the Intermediate Partnership to maintain (a) a debt to cash flow ratio of not more than 2.5 to 1.0 and (b) a cash flow to interest expense ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt to cash flow ratio and cash flow to interest expense ratio were 1.34 to 1.0 and 12.6 to 1.0, respectively, for the trailing twelve months ended December 31, 2019. We remain in compliance with the covenants of the Credit Agreement as of December 31, 2019.

Senior Notes. On April 24, 2017, the Intermediate Partnership and Alliance Finance (as co-issuer), a wholly owned subsidiary of the Intermediate Partnership, issued an aggregate principal amount of $400.0 million of senior unsecured notes due 2025 ("Senior Notes") in a private placement to qualified institutional buyers. The Senior Notes have a term of eight years, maturing on May 1, 2025 (the "Term") and accrue interest at an annual rate of 7.5%. Interest is payable semi-annually in arrears on each May 1 and November 1. The indenture governing the Senior Notes contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of distributions or similar restricted payments, undertaking transactions with affiliates and limitations on asset sales. At any time prior to May 1, 2020, the issuers of the Senior Notes may redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price equal to 107.5% of the principal amount redeemed, plus accrued and unpaid interest, if any, to the redemption date. The issuers of the Senior Notes may also redeem all or a part of the notes at any time on or after May 1, 2020, at redemption prices set forth in the indenture governing the Senior Notes. At any time prior to May 1, 2020, the issuers of the Senior Notes may redeem the Senior Notes at a redemption price equal to the principal amount of the Senior Notes plus a "make-whole" premium, plus accrued and unpaid interest, if any, to the redemption date. The net proceeds from issuance of the Senior Notes and cash on hand were used to repay previous debt obligations (including a make-whole payment of $8.1 million). We incurred discount and debt issuance costs of $7.3 million in connection with issuance of the Senior Notes. These costs are deferred and are currently being amortized as a component of interest expense over the Term.

Accounts Receivable Securitization. On December 5, 2014, certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership entered into a $100.0 million accounts receivable securitization facility ("Securitization Facility"). Under the Securitization Facility, certain subsidiaries sell trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to $100.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a Eurodollar Rate. In January 2019, we extended the term of the Securitization Facility to January 2020. In October 2019, we extended the term from January 2020 to January 2021. At December 31, 2019, we had $73.8 million outstanding under the Securitization Facility.

May 2019 Equipment Financing. On May 17, 2019, the Intermediate Partnership entered into an equipment financing arrangement accounted for as debt, wherein the Intermediate Partnership received $10.0 million in exchange for conveying its interest in certain equipment owned indirectly by the Intermediate Partnership and entering into a master lease agreement for that equipment (the "May 2019 Equipment Financing"). The May 2019 Equipment Financing contains customary terms and events of default and provides for thirty-six monthly payments with an implicit interest rate of 6.25%, maturing on May 1, 2022. Upon maturity, the equipment will revert back to the Intermediate Partnership.

November 2019 Equipment Financing. On November 6, 2019, the Intermediate Partnership entered into an equipment financing arrangement accounted for as debt, wherein the Intermediate Partnership received $53.1 million in exchange for conveying its interest in certain equipment owned indirectly by the Intermediate Partnership and entering into a master lease agreement for that equipment (the "November 2019 Equipment Financing"). The November 2019 Equipment Financing contains an implicit interest rate of 4.75% and provides for a four year term with forty-seven monthly payments of $1.0 million and a balloon payment of $11.6 million upon maturity on November 6, 2023. At maturity, the equipment will revert back to the Intermediate Partnership. The November 2019 Equipment Financing contains customary terms and events of default.

Other. We also have an agreement with a bank to provide additional letters of credit in an amount of $5.0 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers' compensation benefits. At December 31, 2019, we had $5.0 million in letters of credit outstanding under this agreement.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances. We discuss these estimates and judgments with the audit committee of the Board of Directors ("Audit Committee") periodically. Actual results may differ from these estimates. We have provided a description of all significant accounting policies in the notes to our consolidated financial statements. The following critical accounting policies are materially impacted by judgments, assumptions and estimates used in the preparation of our consolidated financial statements:

Business Combinations and Goodwill

We account for business acquisitions using the purchase method of accounting. See "Item 8. Financial Statements and Supplementary Data—Note 3 – Acquisitions" for more information on the Wing and AllDale Acquisitions. Assets acquired and liabilities assumed are recorded at their estimated fair values at the acquisition date. The excess of purchase price over fair value of net assets acquired is recorded as goodwill. Given the time it takes to obtain pertinent information to finalize the acquired business' balance sheet, it may be several quarters before we are able to finalize those initial fair value estimates. Accordingly, it is not uncommon for the initial estimates to be subsequently revised. The results of operations of acquired businesses are included in the consolidated financial statements from the acquisition date.

For the Wing Acquisition, we determined a preliminary fair value for the acquired mineral interests using a weighting of both income and market approaches. Our income approach primarily comprised of a discounted cash flow model. The assumptions used in the discounted cash flow model included estimated production, projected cash flows, forward oil & gas prices and a risk-adjusted discount rate. Our market approach consisted of the observation of recent acquisitions in the Permian Basin to determine a market price for similar mineral interests. We consider our fair value measurements for the Wing Acquisition to be preliminary as we continue to obtain additional information from operators regarding reserve and production quantities and projections for the mineral interests we acquired.

For the AllDale Acquisition, in addition to valuing the acquired assets and liabilities, we were required to value our previously held equity method investments in AllDale I & II just prior to the acquisition and record a gain as the fair value was determined to be higher than the carrying value of our equity method investments. We used a discounted cash flow model to re-measure our equity method investments immediately prior to the AllDale Acquisition as well as to value the mineral interests acquired. Assumptions used in our discounted cash flow model are similar to those discussed in the Wing Acquisition above.

The only indefinite-lived intangible that the Partnership currently has is goodwill. At December 31, 2019, the Partnership had $136.4 million in goodwill. Goodwill is not amortized, but subject to annual reviews on November 30th for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. We have assessed the reporting unit definitions and determined that at December 31, 2019, the Hamilton reporting unit and the MAC reporting unit are the appropriate reporting units for testing goodwill impairment related to the acquisition of these entities.

The Partnership computes the fair value of these reporting units primarily using the income approach (discounted cash flow analysis). The computations require management to make significant estimates. Critical estimates are used as part of these evaluations include, among other things, the discount rate applied to future earnings reflecting a weighted average cost of capital rate, and projected coal price assumptions. Our estimate of the forward coal sales price curve and future sales volumes are critical assumptions used in our discounted cash flow analysis. There were no impairments of goodwill during 2019 or 2018. In future periods, it is reasonably possible that a variety of circumstances could result in an impairment of our goodwill.

A discounted cash flow analysis requires us to make various judgmental assumptions about sales, operating margins, capital expenditures, working capital and coal sales prices. Assumptions about sales, operating margins, capital expenditures and coal sales prices are based on our budgets, business plans, economic projections, and anticipated future cash flows. In determining the fair value of our reporting units, we were required to make significant judgments and estimates regarding the impact of anticipated economic factors on our business. The forecast assumptions used in the period ended December 31, 2019 make certain assumptions about future pricing, volumes and expected maintenance capital expenditures. Assumptions are also made for a "normalized" perpetual growth rate for periods beyond the long range financial forecast period.

Our estimates of fair value are sensitive to changes in all of these variables, certain of which relate to broader macroeconomic conditions outside our control. As a result, actual performance in the near and longer-term could be different from these expectations and assumptions. This could be caused by events such as strategic decisions made in response to economic and competitive conditions and the impact of economic factors, such as over production in coal and low prices of natural gas. In addition, some of the inherent estimates and assumptions used in determining fair value of the reporting units are outside the control of management, including interest rates, cost of capital and our credit ratings. While we believe we have made reasonable estimates and assumptions to calculate the fair value of the reporting units and other intangible assets, it is possible a material change could occur.

Oil & Gas Reserve Values

Estimated oil & gas reserves and estimated market prices for oil & gas are a significant part of our depletion calculations, impairment analyses, and other estimates. Following are examples of how these estimates affect financial results:

- an increase (decrease) in estimated proved oil & gas reserves can reduce (increase) our units of production depreciation, depletion and amortization rates; and
- changes in oil & gas reserves and estimated market prices both impact projected future cash flows from our mineral interests. This in turn can impact our periodic impairment analysis.

The process of estimating oil & gas reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. After being estimated internally, our proved reserves estimates are compared to proved reserves that are prepared by independent experts in connection with our required year end reporting. The data may change substantially over time as a result of numerous factors, including the historical 12 month average price, additional development cost and activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserves estimates could occur from time to time. Such changes could trigger an impairment of our oil & gas mineral interests and have an impact on our depreciation, depletion and amortization expense prospectively.

Estimates of future commodity prices utilized in our impairment analyses consider market information including published forward oil & gas prices. The forecasted price information used in our impairment analyses is consistent with that generally used in evaluating third party operator drilling decisions and our expected acquisition plans, if any. Prices for future periods will impact the production economics underlying oil & gas reserve estimates. In addition, changes in the price of oil & gas also impact certain costs associated with our expected underlying production and future capital costs. The prices of oil & gas are volatile and change from period to period, thus are expected to impact our estimates. Significant unfavorable changes in the estimated future commodity prices could result in an impairment of our oil & gas mineral interests. There were no impairments of our oil & gas mineral interests during 2019.

Workers' Compensation and Pneumoconiosis (Black Lung) Benefits

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. We generally provide for these claims through self-insurance programs. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on our actuary estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates. See "Item 8. Financial Statements and Supplementary Data—Note 19 – Accrued Workers' Compensation and Pneumoconiosis Benefits" for additional discussion. We had accrued liabilities for workers' compensation of $53.3 million and $49.5 million for these costs at December 31, 2019 and 2018, respectively. A one-percentage-point reduction in the discount rate would have increased operating expense by approximately $3.6 million at December 31, 2019. We limit our exposure to traumatic injury claims by purchasing a high deductible insurance policy that starts paying benefits after deductibles for a particular claim year have been met. Our receivables for traumatic injury claims under this policy as of December 31, 2019 and 2018 are $7.7 million and $8.1 million, respectively.

Coal mining companies are subject to Federal Coal Mine Health and Safety Act of 1969, as amended, and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker's pneumoconiosis, or black lung. We provide for these claims through self-insurance programs. Our pneumoconiosis benefits liability is calculated using the service cost method based on the actuarial present value of the estimated pneumoconiosis benefits obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and discount rates. We had accrued liabilities of $97.7 million and $72.1 million for the pneumoconiosis benefits at December 31, 2019 and 2018, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2019 by approximately $3.9 million. Under the service cost method used to estimate our pneumoconiosis benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions, such as the discount rate, are amortized over the remaining service period of active miners.

The discount rate for workers' compensation and pneumoconiosis is derived by applying the FSTE Pension Discount Curve to the projected liability payout. Other assumptions, such as claim development patterns, mortality, disability incidence and medical costs, are based upon standard actuarial tables adjusted for our actual historical experiences whenever possible. We review all actuarial assumptions periodically for reasonableness and consistency and update such factors when underlying assumptions, such as discount rates, change or when sustained changes in our historical experiences indicate a shift in our trend assumptions are warranted.

Impairment of Long-Lived Assets

In addition to oil & gas reserves discussed above in the *Oil & Gas Reserve Values* section, we review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. Long-lived assets and certain intangibles are not reviewed for impairment unless an impairment indicator is noted. Several examples of impairment indicators include:

- A significant decrease in the market price of a long-lived asset;
- A significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition;
- A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset, including an adverse action of assessment by a regulator;
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- A current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset; or
- A current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. The term more likely that not refers to a level of likelihood that is more than 50 percent.

The above factors are not all inclusive, and management must continually evaluate whether other factors are present that would indicate a long-lived asset may be impaired. If there is an indication that the carrying amount of an asset may not be recovered, the asset is monitored by management where changes to significant assumptions are reviewed. Individual assets are grouped for impairment review purposes based on the lowest level for which there is identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a by-mine basis. The amount of impairment is measured by the difference between the carrying value and the fair value of the asset. The fair value of impaired assets is typically determined based on various factors, including the present values of expected future cash flows using a risk adjusted discount rate, the marketability of coal properties and the estimated fair value of assets that could be sold or used at other operations. We recorded asset impairments of $15.2 million in 2019 and $40.5 million in 2018 (see "Item 8. Financial Statements and Supplementary Data—Note 4 – Long-Lived Asset Impairments").

Asset Retirement Obligations

SMCRA and similar state statutes require that mined property be restored in accordance with specified standards and an approved reclamation plan. A liability is recorded for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support surface acreage for both our underground mines and past surface mines. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accrued liabilities of $137.5 million and $137.1 million for these costs are recorded at December 31, 2019 and 2018, respectively. See "Item 8. Financial Statements and Supplementary Data—Note 18 – Asset Retirement Obligations" for additional information. The liability for asset retirement and closing procedures is sensitive to changes in cost estimates and estimated mine lives. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free interest rate.

Accounting for asset retirement obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. Depreciation is generally determined on a units-of-production basis and accretion is generally recognized over the life of the producing assets.

On at least an annual basis, we review our entire asset retirement obligation liability and make necessary adjustments for permit changes approved by state authorities, changes in the timing of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Adjustments to the liability associated with these assumptions resulted in a decrease of $0.7 million and an increase of $5.0 million for the year ended December 31, 2019 and 2018, respectively.

While the precise amount of these future costs cannot be determined with certainty, we have estimated the costs and timing of future asset retirement obligations escalated for inflation, then discounted and recorded at the present value of those estimates. Discounting resulted in reducing the accrual for asset retirement obligations by $102.9 million and $100.3 million at December 31, 2019 and 2018. We estimate that the aggregate undiscounted cost of final mine closure is approximately $240.5 million and $237.4 million at December 31, 2019 and 2018, respectively. If our assumptions differ from actual experiences, or if changes in the regulatory environment occur, our actual cash expenditures and costs that we incur could be materially different than currently estimated.

Universal Shelf

In February 2018, we filed with the SEC a universal shelf registration statement allowing us to issue from time to time an indeterminate amount of debt or equity securities ("2018 Registration Statement"). At February 20, 2020, we had not utilized any amounts available under the 2018 Registration Statement.

Related–Party Transactions

See "Item 8. Financial Statements and Supplementary Data—Note 20 – Related-Party Transactions" for a discussion of our related-party transactions.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $315.9 million and $272.6 million at December 31, 2019 and 2018, respectively. These accruals were chiefly comprised of workers' compensation benefits, pneumoconiosis benefits, and costs associated with asset retirement obligations. These obligations are self-insured except for certain excess insurance coverage for workers' compensation. The accruals of these items were based on estimates of future expenditures based on current legislation, related regulations and other developments. Thus, from time to time, our results of operations may be significantly affected by changes to these liabilities. Please see "Item 8. Financial Statements and Supplementary Data—Note 18 – Asset Retirement Obligations" and "—Note 19 – Accrued Workers' Compensation and Pneumoconiosis Benefits."

Inflation

Any future inflationary or deflationary pressures could adversely affect the results of our operations. For example, at times our results have been significantly impacted by price increases affecting many of the components of our operating expenses such as fuel, steel, maintenance expense and labor. Please see "Item 1A. Risk Factors."

New Accounting Standards

See "Item 8. Financial Statements and Supplementary Data—Note 2 – Summary of Significant Accounting Policies" for a discussion of new accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

We have significant long-term coal supply agreements as evidenced by approximately 78.5% of our sales tonnage being sold under long-term contracts in 2019. Most of the long-term coal supply agreements are subject to price adjustment provisions, which periodically permit an increase or decrease in the contract price, typically to reflect changes in specified indices or changes in production costs resulting from regulatory changes, or both. For additional discussion of coal supply agreements, please see "Item 1. Business—Coal Marketing and Sales" and "Item 8. Financial Statements and Supplementary Data—Note 22 – Concentration of Credit Risk and Major Customers." As of February 14, 2020, our nominal commitment under contract was approximately 29.3 million tons in 2020, 18.4 million tons in 2021 and 6.7 million tons in 2022.

Our results of operations are highly dependent upon the prices we receive for our coal. The short-term coal contracts favored by some of our customers leaves us more exposed to risks of declining price periods. Also, a significant decline in oil & gas prices would have a significant impact on our royalty revenues.

We have exposure to coal and oil & gas sales prices and price risk for supplies that are used directly or indirectly in the normal course of coal and oil & gas production such as steel, electricity and other supplies. We manage our risk for these items through strategic sourcing contracts for normal quantities required by our operations. Historically, we have not utilized any commodity price-hedges or other derivatives related to either our sales price or supply cost risks.

Credit Risk

In 2019, approximately 78.8% of our tons sold were purchased by United States electric utilities and 17.9% were sold into the international markets through brokered transactions. Therefore, our credit risk is primarily with domestic electric power generators and reputable global brokerage firms. Our policy is to independently evaluate each customer's creditworthiness prior to entering into transactions and to constantly monitor outstanding accounts receivable against established credit limits. When deemed appropriate by our credit management department, we will take steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps may include obtaining letters of credit or cash collateral, requiring prepayments for shipments or establishing customer trust accounts held for our benefit in the event of a failure to pay.

Exchange Rate Risk

Almost all of our transactions are denominated in United States dollars, and as a result, we do not have material exposure to currency exchange-rate risks. However, because coal is sold internationally in United States dollars, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide our foreign competitors with a competitive advantage. If our competitors' currencies decline against the United States dollar or against foreign purchasers' local currencies, those competitors may be able to offer lower prices for coal to these purchasers. Furthermore, if the currencies of overseas purchasers were to significantly decline in value in comparison to the United States dollar, those purchasers may seek decreased prices for the coal we sell to them. Consequently, currency fluctuations could adversely affect the competitiveness of our coal in international markets.

Interest Rate Risk

Borrowings under the Revolving Credit Facility and Securitization Facility are at variable rates and, as a result, we have interest rate exposure. Historically, our earnings have not been materially affected by changes in interest rates and we have not utilized interest rate derivative instruments related to our outstanding debt. We had $255.0 million in borrowings under the Revolving Credit Facility and $73.8 million in borrowings under the Securitization Facility at December 31, 2019. A one percentage point increase in the interest rates related to the Revolving Credit Facility and Securitization Facility would result in an annualized increase in interest expense of $3.3 million, based on borrowing levels at December 31, 2019. With respect to our fixed-rate borrowings, we had $400.0 million in borrowings under our Senior Notes and $60.5 million in borrowings under our equipment financings at December 31, 2019. A one percentage point increase in interest rates would result in a decrease of approximately $21.6 million in the estimated fair value of these borrowings.

The table below provides information about our market sensitive financial instruments and constitutes a "forward-looking statement." The fair values of long-term debt are estimated using discounted cash flow analyses, based upon our incremental borrowing rates for similar types of borrowing arrangements as of December 31, 2019 and 2018.

The carrying amounts and fair values of financial instruments are as follows:

Expected Maturity Dates as of December 31, 2019	2020	2021	2022	2023	2024	Thereafter	Total	Fair Value December 31, 2019
				(in thousands)				
Fixed rate debt	$ 13,158	$ 13,847	$ 12,403	$ 21,072	$ —	$ 400,000	$ 460,480	$ 407,775
Weighted-average interest rate	7.20 %	7.26 %	7.33 %	7.41 %	7.50 %	7.50 %		
Variable rate debt	$ —	$ 328,800	$ —	$ —	$ —	$ —	$ 328,800	$ 328,431
Weighted-average interest rate (1)	4.12 %	4.39 %	—	—	—	—		

Expected Maturity Dates as of December 31, 2018	2019	2020	2021	2022	2023	Thereafter	Total	Fair Value December 31, 2018
				(in thousands)				
Fixed rate debt	$ —	$ —	$ —	$ —	$ —	$ 400,000	$ 400,000	$ 403,319
Weighted-average interest rate	7.50 %	7.50 %	7.50 %	7.50 %	7.50 %	7.50 %		
Variable rate debt	$ 92,000	$ —	$ 175,000	$ —	$ —	$ —	$ 267,000	$ 266,545
Weighted-average interest rate (1)	4.85 %	4.88 %	4.88 %	—	—	—		

(1) Interest rate of variable rate debt equal to the rate effective at December 31, 2019 and 2018, held constant for the remaining term of the outstanding borrowing.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

The Board of Directors of Alliance Resource Management GP, LLC
and the Partners of Alliance Resource Partners, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, cash flows, and partners' capital for each of the three years in the period ended December 31, 2019, and the related notes and financial statement schedule listed in the Index at Item 15(a)(2) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Partnership at December 31, 2019 and 2018, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 20, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion of the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for the AllDale and Wing Acquisitions

Description of the Matter	As more fully described in Note 3 to the consolidated financial statements, during 2019 the Partnership completed the acquisitions of AllDale Minerals, LP and AllDale Minerals II, LP (the "AllDale Acquisition") (completed on January 3, 2019) and certain oil and gas mineral interests from Wing Resources LLC and Wing Resources II, LLC (the "Wing Acquisition") (completed on August 2, 2019), for cash consideration of approximately $176.0 million and $145.0 million, respectively. As disclosed in Note 3, both transactions were accounted for as business combinations. Additionally, given the previous equity-method investments acquired in the AllDale Acquisition, the previously-held interests were revalued, resulting in a remeasurement gain of $177.0 million. Auditing the Partnership's accounting for these acquisitions was complex due to the significant estimation required by management to determine the fair value of the underlying assets, specifically the value of mineral interests in proved and unproved properties positioned in various strategic locations throughout the United States. The Partnership determined the fair value of the underlying assets for the AllDale Acquisition using an income approach, primarily comprised of discounted cash flow models. The Partnership determined the fair value of the underlying assets for the Wing Acquisition partially using an income approach and partially using a market approach. The significant assumptions used in the income approach included estimated proved and unproved reserves as estimated by petroleum engineering specialists, and related reserve risk adjustment factors, discount rates, and forward commodity price information. These significant assumptions are forward looking and could be affected by future economic and market conditions.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Partnership's controls over its accounting for the acquisitions process. For example, we tested controls over management's review of the valuation models, including the identification of significant assumptions used to develop the estimate. Our audit procedures included, among others, evaluating the significant assumptions used and testing the completeness and accuracy of the discounted cash flow models and underlying financial data used in the calculation of the fair values. For the proved and unproved reserves assumption, we considered the professional qualifications and objectivity of the petroleum engineering specialists. We also involved our valuation specialists to assist in our evaluation of certain significant assumptions used to determine fair value, including reserve risk adjustment factors, discount rates, and forward-looking commodity prices. Additionally, we searched for and evaluated information that corroborates and or contradicts the Company's assumptions and performed an independent corroborative calculation of discount rates.

Valuation of workers' compensation and black lung liabilities

Description of the Matter	As more fully described at Note 19 to the consolidated financial statements, the Partnership provides income replacement and medical treatment for work-related traumatic injury claims, as required by applicable laws. Workers' compensation laws also compensate survivors of workers who suffer employment-related deaths. Certain of the Partnership's mine operating entities are liable under state statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay benefits for black lung disease (or pneumoconiosis) to eligible employees and former employees and their dependents. At December 31, 2019, the Partnership's aggregate workers' compensation and black lung liabilities were $151 million. Auditing management's estimate of the workers' compensation and black lung liability was complex due to the use of a blend of actuarial projection methods and numerous assumptions including claim development patterns, costs, and mortality in the liability calculations.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Partnership's controls over management's workers' compensation and black lung liability process. For example, we tested controls over management's review of the liability calculations and the appropriateness of the significant assumptions used, including the completeness and accuracy of the underlying data. To test the workers' compensation and black lung liability, our audit procedures included, among others, evaluating the methodology used, the significant actuarial assumptions described above and the underlying data used by the Partnership. We involved our actuarial specialists to assist in evaluating management's methodology and for testing the claim development patterns, costs and mortality assumptions. We compared the claim development pattern and cost assumptions used by management for consistency with historical experience and current trends. We also developed independent ranges and compared those ranges to management's best estimate. To evaluate the use of mortality tables, we assessed whether the information used by management is consistent with publicly-available information. We also tested the completeness and accuracy of the underlying data used by management, including the claims data provided to management's actuarial specialists.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2011.

Tulsa, Oklahoma
February 20, 2020

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2019 AND 2018
(In thousands, except unit data)

	December 31,	
	2019	2018
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 36,482	$ 244,150
Trade receivables	161,679	174,914
Other receivables	256	395
Inventories, net	101,305	59,206
Advance royalties	1,844	1,274
Prepaid expenses and other assets	18,019	20,747
Total current assets	319,585	500,686
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	3,684,008	2,925,808
Less accumulated depreciation, depletion and amortization	(1,675,022)	(1,513,450)
Total property, plant and equipment, net	2,008,986	1,412,358
OTHER ASSETS:		
Advance royalties	52,057	42,923
Equity method investments	28,529	161,309
Equity securities	—	122,094
Goodwill	136,399	136,399
Operating lease right-of-use assets	17,660	—
Other long-term assets	23,478	18,979
Total other assets	258,123	481,704
TOTAL ASSETS	$ 2,586,694	$ 2,394,748
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 80,566	$ 96,397
Accrued taxes other than income taxes	15,768	16,762
Accrued payroll and related expenses	36,575	43,113
Accrued interest	5,664	5,022
Workers' compensation and pneumoconiosis benefits	11,175	11,137
Current finance lease obligations	8,368	46,722
Current operating lease obligations	3,251	—
Other current liabilities	21,062	19,718
Current maturities, long-term debt, net	13,157	92,000
Total current liabilities	195,586	330,871
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities, net	768,194	564,004
Pneumoconiosis benefits	94,389	68,828
Accrued pension benefit	44,858	43,135
Workers' compensation	45,503	41,669
Asset retirement obligations	133,018	127,655
Long-term finance lease obligations	2,224	10,595
Long-term operating lease obligations	14,316	—
Other liabilities	23,182	20,304
Total long-term liabilities	1,125,684	876,190
Total liabilities	1,321,270	1,207,061
PARTNERS' CAPITAL:		
ARLP Partners' Capital:		
Limited Partners - Common Unitholders 126,915,597 and 128,095,511 units outstanding, respectively	1,331,482	1,229,268
Accumulated other comprehensive loss	(77,993)	(46,871)
Total ARLP Partners' Capital	1,253,489	1,182,397
Noncontrolling interest	11,935	5,290
Total Partners' Capital	1,265,424	1,187,687
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 2,586,694	$ 2,394,748

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2019, 2018 AND 2017
(In thousands, except unit and per unit data)

	Year Ended December 31, 2019	2018	2017
SALES AND OPERATING REVENUES:			
Coal sales	$ 1,762,442	$ 1,844,808	$ 1,711,114
Oil & gas royalties	51,735	—	—
Transportation revenues	99,503	112,385	41,700
Other revenues	48,040	45,664	43,406
Total revenues	1,961,720	2,002,857	1,796,220
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	1,182,100	1,207,713	1,091,855
Transportation expenses	99,503	112,385	41,700
Outside coal purchases	23,357	1,466	—
General and administrative	72,997	68,298	61,760
Depreciation, depletion and amortization	309,075	280,225	268,981
Settlement gain	—	(80,000)	—
Asset impairment	15,190	40,483	—
Total operating expenses	1,702,222	1,630,570	1,464,296
INCOME FROM OPERATIONS	259,498	372,287	331,924
Interest expense (net of interest capitalized of $1,211, $1,306 and $551, respectively)	(45,875)	(40,218)	(39,385)
Interest income	379	159	94
Equity method investment income	2,203	22,189	13,860
Equity securities income	12,906	15,696	6,398
Acquisition gain	177,043	—	—
Debt extinguishment loss	—	—	(8,148)
Other income (expense)	561	(2,621)	(332)
INCOME BEFORE INCOME TAXES	406,715	367,492	304,411
INCOME TAX EXPENSE (BENEFIT)	(211)	22	210
NET INCOME	406,926	367,470	304,201
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	(7,512)	(866)	(563)
NET INCOME ATTRIBUTABLE TO ARLP	$ 399,414	$ 366,604	$ 303,638
NET INCOME ATTRIBUTABLE TO ARLP			
GENERAL PARTNER	$ —	$ 1,560	$ 21,904
LIMITED PARTNERS	$ 399,414	$ 365,044	$ 281,734
EARNINGS PER LIMITED PARTNER UNIT - BASIC AND DILUTED	$ 3.07	$ 2.74	$ 2.80
WEIGHTED-AVERAGE NUMBER OF UNITS OUTSTANDING – BASIC AND DILUTED	128,116,670	130,758,169	98,707,696

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2019, 2018 AND 2017
(In thousands)

	Year Ended December 31,		
	2019	**2018**	**2017**
NET INCOME	$ 406,926	$ 367,470	$ 304,201
OTHER COMPREHENSIVE INCOME (LOSS):			
Defined benefit pension plan			
Amortization of prior service cost (1)	186	186	186
Net actuarial loss	(7,350)	(3,326)	(6,610)
Amortization of net actuarial loss (1)	3,922	3,608	3,054
Total defined benefit pension plan adjustments	(3,242)	468	(3,370)
Pneumoconiosis benefits			
Net actuarial gain (loss)	(23,298)	4,599	(7,938)
Amortization of net actuarial loss (gain) (1)	(4,582)	2	(2,092)
Total pneumoconiosis benefits adjustments	(27,880)	4,601	(10,030)
OTHER COMPREHENSIVE INCOME (LOSS)	(31,122)	5,069	(13,400)
COMPREHENSIVE INCOME	375,804	372,539	290,801
Less: Comprehensive income attributable to noncontrolling interest	(7,512)	(866)	(563)
COMPREHENSIVE INCOME ATTRIBUTABLE TO ARLP	$ 368,292	$ 371,673	$ 290,238

(1) Amortization of prior service cost and actuarial gain or loss is included in the computation of net periodic benefit cost (see Notes 15 and 19 for additional details).

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2019, 2018 AND 2017
(In thousands)

	Year Ended December 31,		
	2019	**2018**	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 406,926	$ 367,470	$ 304,201
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	309,075	280,225	268,981
Non-cash compensation expense	11,934	12,114	12,326
Asset retirement obligations	4,087	3,926	3,793
Coal inventory adjustment to market	4,895	1,455	449
Equity investment income	(2,203)	(22,189)	(13,860)
Distributions from equity method investments	2,203	21,971	13,939
Income from equity securities paid-in-kind	(712)	(15,696)	(6,398)
Net loss (gain) on sale of property, plant and equipment	109	(1,285)	(696)
Asset impairment	15,190	40,483	—
Acquisition gain, net	(177,043)	—	—
Cash received on redemption of equity securities in excess of investment	(11,482)	—	—
Valuation allowance of deferred tax assets	(413)	(1,560)	(3,339)
Debt extinguishment loss	—	—	8,148
Other	5,677	3,171	6,212
Changes in operating assets and liabilities:			
Trade receivables	20,841	6,757	(29,639)
Other receivables	3,726	(249)	133
Inventories, net	(35,082)	(747)	(1,449)
Prepaid expenses and other assets	6,136	7,387	(6,067)
Advance royalties	(9,876)	(8,782)	(13,591)
Accounts payable	(17,671)	(813)	25,499
Accrued taxes other than income taxes	(994)	(3,614)	2,063
Accrued payroll and related benefits	(6,538)	7,362	(5,825)
Pneumoconiosis benefits	(2,292)	1,837	(159)
Workers' compensation	3,845	(4,900)	(4,371)
Other	(15,443)	22	(4,234)
Total net adjustments	107,969	326,875	251,915
Net cash provided by operating activities	514,895	694,345	556,116
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(305,858)	(233,480)	(145,088)
Change in accounts payable and accrued liabilities	(81)	(1,051)	7,404
Proceeds from sale of property, plant and equipment	1,266	2,409	2,139
Contributions to equity method investments	—	(15,600)	(20,688)
Purchase of equity security	—	—	(100,000)
Distributions received from investments in excess of cumulative earnings	2,501	2,473	11,462
Payments for acquisitions of businesses, net of cash acquired	(320,232)	—	—
Cash received from redemption of equity securities	134,288	—	—
Net cash used in investing activities	(488,116)	(245,249)	(244,771)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under securitization facility	184,500	304,600	100,000
Payments under securitization facility	(202,700)	(285,000)	(127,600)
Proceeds from equipment financings	63,086	—	—
Payments on equipment financings	(2,607)	—	—
Payment on term loan	—	—	(50,000)
Borrowings under revolving credit facilities	400,000	245,000	215,486
Payments under revolving credit facilities	(320,000)	(100,000)	(440,486)
Borrowing under long-term debt	—	—	400,000
Payment on long-term debt	—	—	(145,000)
Payments on finance lease obligations	(46,725)	(29,353)	(27,071)
Payment of debt issuance costs	—	—	(16,487)
Payment for debt extinguishment	—	—	(8,148)
Payments for purchases of units under unit repurchase program	(22,892)	(70,604)	—
Contributions to consolidated company from affiliate noncontrolling interest	—	—	251
Net settlement of withholding taxes on issuance of units in deferred compensation plans	(7,817)	(2,081)	(2,988)
Cash contributions by General Partner	—	41	1,105
Cash contribution by affiliated entity	—	2,142	—
Cash obtained in Simplification Transactions	—	1,139	—
Distributions paid to Partners	(278,425)	(275,902)	(240,812)
Other	(867)	(1,684)	(2,621)
Net cash used in financing activities	(234,447)	(211,702)	(344,371)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(207,668)	237,394	(33,026)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	244,150	6,756	39,782
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 36,482	$ 244,150	$ 6,756

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2019, 2018 AND 2017
(In thousands, except unit data)

	Number of Limited Partner Units	Limited Partners' Capital	General Partners' Capital (Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Partners' Capital
Balance at January 1, 2017	74,375,025	$ 1,400,202	$ (273,788)	$ (38,540)	$ 5,550	$ 1,093,424
Comprehensive income:						
Net income	—	281,734	21,904	—	563	304,201
Actuarially determined long-term liability adjustments	—	—	—	(13,400)	—	(13,400)
Total comprehensive income						290,801
Settlement of deferred compensation plans	222,011	(2,988)	—	—	—	(2,988)
Issuance of units to MGP in Exchange Transaction	56,100,000	14,171	(14,171)	—	—	—
Issuance of units to SGP in Exchange Transaction	7,181	(320,838)	320,838	—	—	—
Exchange Transaction fees	—	(1,605)	—	—	—	(1,605)
Common unit-based compensation	—	12,326	—	—	—	12,326
Distributions on deferred common unit-based compensation	—	(3,248)	—	—	—	(3,248)
General Partners contributions	—	—	1,105	—	—	1,105
Contributions to consolidated company from noncontrolling interest	—	—	—	—	251	251
Distributions from consolidated company to noncontrolling interest	—	—	—	—	(1,016)	(1,016)
Distributions to Partners	—	(196,535)	(41,029)	—	—	(237,564)
Balance at December 31, 2017	130,704,217	1,183,219	14,859	(51,940)	5,348	1,151,486
Comprehensive income:						
Net income	—	365,044	1,560	—	866	367,470
Actuarially determined long-term liability adjustments	—	—	—	5,069	—	5,069
Total comprehensive income						372,539
Settlement of deferred compensation plans	199,039	(2,745)	—	—	—	(2,745)
Issuance of units to Owners of SGP in Simplification Transactions	1,322,388	14,742	(15,106)	—	—	(364)
Issuance of units to SGP related to Exchange Transaction	20,960	—	—	—	—	—
Simplification Transactions fees	—	(96)	—	—	—	(96)
Contribution of units and cash by affiliated entity	(467,018)	2,142	—	—	—	2,142
Purchase of units under unit repurchase program	(3,684,075)	(70,604)	—	—	—	(70,604)
Common unit-based compensation	—	12,114	—	—	—	12,114
Distributions on deferred common unit-based compensation	—	(3,855)	—	—	—	(3,855)
General Partner contribution	—	—	41	—	—	41
Distributions from consolidated company to noncontrolling interest	—	—	—	—	(924)	(924)
Distributions to Partners	—	(270,693)	(1,354)	—	—	(272,047)
Balance at December 31, 2018	128,095,511	1,229,268	—	(46,871)	5,290	1,187,687
Comprehensive income:						
Net income	—	399,414	—	—	7,512	406,926
Actuarially determined long-term liability adjustments	—	—	—	(31,122)	—	(31,122)
Total comprehensive income						375,804
Settlement of deferred compensation plans	596,650	(7,817)	—	—	—	(7,817)
Purchase of units under unit repurchase program	(1,776,564)	(22,892)	—	—	—	(22,892)
Common unit-based compensation	—	11,934	—	—	—	11,934
Distributions on deferred common unit-based compensation	—	(3,670)	—	—	—	(3,670)
Distributions from consolidated company to noncontrolling interest	—	—	—	—	(867)	(867)
Distributions to Partners	—	(274,755)	—	—	—	(274,755)
Balance at December 31, 2019	126,915,597	$ 1,331,482	$ —	$ (77,993)	$ 11,935	$ 1,265,424

See notes to consolidated financial statements.

1. ORGANIZATION AND PRESENTATION

Significant Relationships Referenced in Notes to Consolidated Financial Statements

- References to "we," "us," "our" or "ARLP Partnership" mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.
- References to "ARLP" mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.
- References to "MGP" mean Alliance Resource Management GP, LLC, ARLP's sole general partner and, prior to the Exchange Transaction discussed below, it was also referred to as the managing general partner to distinguish MGP from SGP. As a result of the Exchange Transaction, SGP no longer holds any general partner interests.
- References to "SGP" mean Alliance Resource GP, LLC, ARLP's special general partner prior to the Exchange Transaction discussed below. SGP is indirectly wholly owned by Joseph W. Craft III, the Chairman, President and Chief Executive Officer ("CEO") of MGP, and Kathleen S. Craft, who are collectively referred to in such capacity as the "Owners of SGP." The Owners of SGP held approximately 34.48% of the outstanding AHGP common units prior to the Simplification Transactions discussed below.
- References to "Intermediate Partnership" mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P.
- References to "Alliance Coal" mean Alliance Coal, LLC, the holding company for the coal mining operations of Alliance Resource Operating Partners, L.P.
- References to "AHGP" mean Alliance Holdings GP, L.P., individually and not on a consolidated basis as the parent company of MGP prior to the Simplification Transactions discussed below and as a wholly owned subsidiary of ARLP subsequent to the Simplification Transactions.

Organization

ARLP is a Delaware limited partnership listed on the NASDAQ Global Select Market under the ticker symbol "ARLP." ARLP was formed in May 1999 and completed its initial public offering on August 19, 1999 when it acquired substantially all of the coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation ("ARH"), and its subsidiaries. We are managed by our sole general partner, MGP, a Delaware limited liability company which holds a non-economic general partner interest in ARLP. Prior to the Simplification Transactions, MGP was a wholly owned indirect subsidiary of AHGP. Alliance GP, LLC ("AGP"), which is indirectly wholly owned by Mr. Craft, was the general partner of AHGP prior to the Simplification Transactions and became the direct owner of MGP as a result of the transactions. See discussions under *Partnership Simplification* regarding changes in ownership of ARLP and MGP as a result of the Exchange Transaction in 2017 and Simplification Transactions in 2018.

Partnership Simplification

On July 28, 2017, the conflicts committee ("Conflicts Committee") of the board of directors ("Board of Directors") of MGP and AGP's board of directors approved a transaction to simplify our partnership structure. Pursuant to that transaction, which closed on the same date, MGP contributed to ARLP all of its incentive distribution rights ("IDRs") and its 0.99% managing general partner interest in ARLP in exchange for 56,100,000 ARLP common units and a non-economic general partner interest in ARLP. In conjunction with this transaction and on the same economic basis as MGP, SGP also contributed to ARLP its 0.01% general partner interests in both ARLP and the Intermediate Partnership in exchange for 28,141 ARLP common units (collectively the "Exchange Transaction").

On February 22, 2018, the Board of Directors and the board of directors of AGP approved a simplification agreement (the "Simplification Agreement"), pursuant to which, among other things, through a series of transactions (the "Simplification Transactions"):

i. AHGP would become a wholly owned subsidiary of ARLP,

ii. all of the issued and outstanding AHGP common units would be canceled and converted into the right to receive the ARLP common units held by AHGP and its subsidiaries,
iii. in exchange for a number of ARLP common units calculated pursuant to the Simplification Agreement, MGP's 1.0001% general partner interest in our Intermediate Partnership and MGP's 0.001% managing member interest in our subsidiary, Alliance Coal, would be contributed to us, and
iv. MGP would remain ARLP's sole general partner and would be a wholly owned subsidiary of AGP, and thus no control, management, or governance changes with respect to our business would occur.

The Simplification Agreement and the transactions contemplated thereby were approved by the written consent of approximately 68% of the holders of AHGP common units outstanding as of April 25, 2018, the record date for the consent solicitation. On May 31, 2018, ARLP, AHGP and the other parties to the Simplification Agreement completed the transactions contemplated by the Simplification Agreement.

As part of the Simplification Transactions, (i) each AHGP common unit that was issued and outstanding at the effective time of the Simplification Transactions was canceled and converted into the right to receive a portion of the ARLP common units held by AHGP and its subsidiaries, and (ii) SGP became the sole limited partner in AHGP. Each outstanding AHGP common unit, other than certain AHGP common units held by the Owners of SGP, converted into the right to receive approximately 1.4782 ARLP common units held by AHGP and its subsidiaries. The remaining AHGP common units held by the Owners of SGP were canceled and converted into the right to receive 29,188,997 ARLP common units which equaled (i) the product of the number of certain AHGP common units held by the Owners of SGP multiplied by 1.4782, minus (ii) 1,322,388 ARLP common units. In addition, ARLP issued 1,322,388 ARLP common units to the Owners of SGP in exchange for causing SGP to contribute to ARLP its remaining limited partner interest in AHGP, which included AHGP's indirect ownership of a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal, resulting in an overall exchange ratio to the Owners of SGP equal to that of the other AHGP unitholders. Upon the issuance of ARLP common units to the Owners of SGP in exchange for the limited partner interest in AHGP, ARLP became a) the sole limited partner of AHGP and b) through AHGP, the indirect owner of a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal.

AllDale I & II Acquisition

On January 3, 2019 (the "AllDale Acquisition Date"), we acquired all of the limited partner interests not owned by Cavalier Minerals JV, LLC ("Cavalier Minerals") in AllDale Minerals LP ("AllDale I") and AllDale Minerals II, LP ("AllDale II", and collectively with AllDale I, "AllDale I & II") and the general partner interests in AllDale I & II (the "AllDale Acquisition"). As a result of the AllDale Acquisition and our previous investments held through Cavalier Minerals, we acquired control of approximately 43,000 net royalty acres in premier oil & gas resource plays. The AllDale Acquisition provides us with diversified exposure to industry leading operators and is consistent with our general business strategy to grow our Minerals segment. See Note 3 – Acquisitions for more information.

Wing Acquisition

On August 2, 2019, our subsidiary AR Midland, LP ("AR Midland") acquired from Wing Resources LLC and Wing Resources II LLC (collectively, "Wing") approximately 9,000 net royalty acres in the Midland Basin, with exposure to more than 400,000 gross acres (the "Wing Acquisition"). The Wing Acquisition enhances our ownership position in the Permian Basin, expands our exposure to industry leading operators and furthers our business strategy to grow our Minerals segment. Following the Wing Acquisition, we hold approximately 55,700 net royalty acres in premier oil & gas basins including our investment in AllDale Minerals III, LP ("AllDale III"). See Note 3 – Acquisitions for more information.

Presentation

The consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of December 31, 2019 and 2018, and results of our operations, comprehensive income, cash flows and changes in partners' capital for each of the three years in the period ended December 31, 2019. All of our intercompany transactions and accounts have been eliminated.

As a result of the AllDale Acquisition, we now control the underlying oil & gas mineral interests held by AllDale I & II. This control over the oil & gas mineral interests held by AllDale I & II reflects a strategic change in how we manage our business and how resources are allocated by our chief operating decision maker. Due to this strategic change, we realigned our reportable segments in 2019 to include our oil & gas mineral interests within a new Minerals reportable segment. In August 2019, we added the Wing Acquisition to the Minerals reportable segment. As part of our realignment, we have also included the operations of our Mt. Vernon Transfer Terminal, LLC ("Mt. Vernon") and Mid-America Carbonates, LLC ("MAC") subsidiaries in the Illinois Basin reportable segment rather than Other and Corporate to better reflect our Illinois Basin related activities. Prior periods have been recast to include our oil & gas mineral interests in the Minerals segment, and Mt. Vernon and MAC in the Illinois Basin segment. See Note 23 – Segment Information for further discussion of our reportable segments.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation—The consolidated financial statements present the consolidated financial position, results of operations and cash flows of ARLP, the Intermediate Partnership, Alliance Coal and other directly and indirectly wholly- and majority-owned subsidiaries of ARLP. For the periods presented prior to the Simplification Transactions, MGP's interests in both Alliance Coal and the Intermediate Partnership are reported as part of the general partner's interest in the ARLP Partnership's consolidated financial statements. For the periods presented prior to the Exchange Transaction, MGP's managing general partner interest and IDRs in ARLP and the SGP's special general partner interests in ARLP and the Intermediate Partnership are also reported as part of the general partners' interest in the ARLP Partnership's consolidated financial statements. All intercompany transactions and accounts have been eliminated. See Note 10 – Partners' Capital for more information regarding MGP's previously held IDR's in ARLP. See Note 1 – Organization and Presentation for more information regarding the Simplification Transactions and Exchange Transaction.

Variable Interest Entity ("VIE")—VIEs are primarily entities that lack sufficient equity to finance their activities without additional financial support from other parties or whose equity holders, as a group, lack one or more of the following characteristics: (a) direct or indirect ability to make decisions, (b) obligation to absorb expected losses or (c) right to receive expected residual returns. A VIE must be evaluated quantitatively and qualitatively to determine the primary beneficiary, which is the reporting entity that has (a) the power to direct activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary is required to consolidate the VIE for financial reporting purposes.

To determine a VIE's primary beneficiary, we perform a qualitative assessment to determine which party, if any, has the power to direct activities of the VIE and the obligation to absorb losses and/or receive its benefits. This assessment involves identifying the activities that most significantly impact the VIE's economic performance and determine whether it, or another party, has the power to direct those activities. When evaluating whether we are the primary beneficiary of a VIE, we perform a qualitative analysis that considers the design of the VIE, the nature of our involvement and the variable interests held by other parties. See Note 11 – Variable Interest Entities for further information.

Estimates—The preparation of consolidated financial statements in conformity with generally accepted accounting principles of the United States ("GAAP") requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. Actual results could differ from those estimates. Significant estimates and assumptions include:

- Impairment assessments of investments, property, plant and equipment, and goodwill;
- Asset retirement obligations;
- Pension valuation variables;
- Workers' compensation and pneumoconiosis valuation variables;
- Acquisition related purchase price allocations; and
- Life of mine assumptions;
- Oil & gas reserve quantities and carrying amounts; and
- Determination of oil & gas revenue accruals

These significant estimates and assumptions are discussed throughout these notes to the consolidated financial statements.

Fair Value Measurements—We apply fair value measurements to certain assets and liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Fair value is based upon assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and risks inherent in valuation techniques and inputs to valuations. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability (the market for which the reporting entity would be able to maximize the amount received or minimize the amount paid). Valuation techniques used in our fair value measurements are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our own market assumptions.

We use the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- Level 1 – Quoted prices for identical assets and liabilities in active markets that we have the ability to access at the measurement date.

- Level 2 – Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model derived valuations whose inputs are observable or whose significant value drivers are observable.

- Level 3 – Unobservable inputs for the asset or liability including situations where there is little, if any, market activity for the asset or liability.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall into different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement requires judgment, considering factors specific to the asset or liability. Significant fair value measurements are used in our significant estimates and are discussed throughout these notes.

Cash and Cash Equivalents—Cash and cash equivalents include cash on hand and on deposit, including highly liquid investments with maturities of three months or less.

Cash Management—The cash flows from operating activities section of our consolidated statements of cash flows reflects an adjustment for $14.0 million representing book overdrafts at December 31, 2017. We did not have material book overdrafts at December 31, 2019 and 2018.

Inventories—Coal inventories are stated at the lower of cost or net realizable value on a first-in, first-out basis. Supply inventories are stated at an average cost basis, less a reserve for obsolete and surplus items.

Business Combinations—For acquisitions accounted for as a business combination, we record the assets acquired, including identified intangible assets and liabilities assumed at their fair value, which in many instances involves estimates based on third-party valuations, such as appraisals, or internal valuations based on discounted cash flow analyses or other valuation techniques.

Goodwill—Goodwill represents the excess of cost over the fair value of net assets of acquired businesses. Goodwill is not amortized, but instead is evaluated for impairment periodically. We evaluate goodwill for impairment annually on November 30th, or more often if events or circumstances indicate that goodwill might be impaired. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. There were no impairments of goodwill during 2019 or 2018.

Property, Plant and Equipment—Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Interest costs associated with major asset additions are capitalized during the construction period. Maintenance and repairs that do not extend the useful life or increase productivity of the asset are charged to operating expense as incurred. Exploration expenditures are charged to operating expense as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Land, machinery and equipment under capital lease agreements are capitalized and amortized over the useful lives of the assets given that in each case, ownership transfers at the end of the lease term. Preparation plants, processing facilities and mineral rights, assuming current production estimates, are depreciated or depleted using the units-of-production method over a range from 1 to 28 years. Mining equipment and other plant and equipment assets are depreciated principally using the straight-line method over the estimated useful lives of the assets, ranging from 1 to 28 years, limited by the remaining estimated life of each mine. Depreciable lives for buildings, office equipment and improvements range from 1 to 25 years. Gains or losses arising from retirements are included in operating expenses. Depletion of coal mineral rights is provided on the basis of tonnage mined in relation to estimated recoverable tonnage, which equals estimated proven and probable reserves. Therefore, our coal mineral rights are depleted based on only proven and probable reserves. See Oil & Gas Reserve Quantities and Carrying Amounts below for a discussion of our accounting policies for oil & gas properties.

Mine Development Costs—Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized on a units of production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine's production capacity and is not considered to shift the mine into the production phase.

Long-Lived Asset Impairment—We review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. To the extent the carrying amount is not recoverable, the amount of impairment is measured by the difference between the carrying value and the fair value of the asset (See Note 4 – Long-Lived Asset Impairments).

Oil & Gas Reserve Quantities and Carrying Amounts—We are wholly dependent on third-party operators to explore, develop, produce and operate the properties associated with our mineral interests. We follow the successful efforts method of accounting for our oil & gas mineral interests. Under this method, costs to acquire mineral interests in oil & gas properties are capitalized when incurred. The costs of mineral interests in unproved properties are capitalized pending the results of exploration and leasing efforts by operators. As mineral interests in unproved properties are determined to be proved, the related costs are transferred to proved oil & gas properties.

Mineral interests in oil & gas properties are grouped using a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, which we may also refer to as a depletable group. Mineral interests in proved oil & gas properties are depleted based on the units-of-production method. Proved reserves are quantities of oil & gas that can be estimated with reasonable certainty to be recoverable in the future from a given date forward, from known reservoirs, under existing economic conditions, operating methods, and government regulations. Proved developed resources are the quantities expected to be recovered through our operators' existing wells with existing equipment, infrastructure and operating methods.

We evaluate impairment of our mineral interests in proved properties whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. This evaluation is performed on a depletable group basis. We compare the undiscounted projected future cash flows expected in connection with a depletable group to its unamortized carrying amount to determine recoverability. When the carrying amount of a depletable group exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, future expenditures, and a risk-adjusted discount rate.

Our mineral interests in unproved properties are also assessed for impairment periodically on a depletable group basis when facts and circumstances indicate that the carrying value may not be recoverable. Impairment of individual unproved properties whose acquisition costs are relatively significant are assessed on a property-by-property basis, and an impairment loss is recognized to the extent the carrying value exceeds the estimated recoverable value for the property. Impairment of unproved properties whose acquisition costs are not individually significant are assessed on a group basis. Any amount of loss to be recognized and the amount of a valuation allowance needed to provide for impairment of those properties is determined by amortizing those properties in the aggregate on the basis of historical experience and other relevant information, such as the relative proportion of such properties on which proved reserves have been found in the past. The carrying value of unproved properties, including unleased mineral rights, are determined based on management's assessment of fair value using factors similar to those previously noted for proved properties, as well as geographic and geologic data.

Upon the sale of a complete depletable group, the book value thereof, less proceeds or salvage value, are charged to income. Upon the sale or retirement of an aggregation of interests which make up less than a complete depletable group, the proceeds are credited to accumulated depreciation, depletion and amortization, unless doing so would significantly alter the depreciation, depletion and amortization rate of the depletable group, in which case a gain or loss would be recorded.

Intangibles—Intangibles subject to amortization include contracts with covenants not to compete, customer contracts acquired from other parties and mining permits. Intangibles other than customer contracts are amortized on a straight-line basis over their useful life. Intangibles for customer contracts are amortized on a per unit basis over the terms of the contracts. Amortization expense attributable to intangibles was $9.1 million, $6.9 million and $10.5 million for the years ending December 31, 2019, 2018 and 2017, respectively. Our intangibles are included in *Prepaid expenses and other assets* and *Other long-term assets* on our consolidated balance sheets at December 31, 2019 and 2018. Our intangibles are summarized as follows:

	December 31, 2019			December 31, 2018		
	Original Cost	**Accumulated Amortization**	**Intangibles, Net**	**Original Cost**	**Accumulated Amortization**	**Intangibles, Net**
	(in thousands)					
Non-compete agreements	$ 9,803	$ (9,440)	$ 363	$ 9,697	$ (8,385)	$ 1,312
Customer contracts and other	32,371	(24,258)	8,113	23,000	(16,293)	6,707
Mining permits	1,500	(307)	1,193	1,500	(241)	1,259
Total	$ 43,674	$ (34,005)	$ 9,669	$ 34,197	$ (24,919)	$ 9,278

Amortization expense attributable to intangible assets is estimated as follows:

Year Ended December 31,	(in thousands)
2020	$ 4,495
2021	2,952
2022	647
2023	647
2024	66
Thereafter	862

Investments—Our investments and ownership interests in equity securities without readily determinable fair values in entities in which we do not have a controlling financial interest or significant influence are accounted for using a measurement alternative other than fair value which is historical cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for identical or similar investments of the same entity. Distributions received on those investments are recorded as income unless those distributions are considered a return on investment, in which case the historical cost is reduced. We accounted for our ownership interests in Kodiak Gas Services, LLC ("Kodiak") as equity securities without readily determinable fair values. In the first quarter of 2019, Kodiak redeemed our preferred interests and therefore Kodiak ceased to be an equity security investment. See Note 10 – Investments for further discussion of this investment.

Our investments and ownership interests in entities in which we do not have a controlling financial interest are accounted for under the equity method of accounting if we have the ability to exercise significant influence over the entity. Investments accounted for under the equity method are initially recorded at cost, and the difference between the basis of our investment and the underlying equity in the net assets of the joint venture at the investment date, if any, is amortized over the lives of the related assets that gave rise to the difference.

As of December 31, 2019, we held an equity method investment in AllDale III through our subsidiary, Alliance Minerals, LLC ("Alliance Minerals"). Prior to the AllDale Acquisition, our equity method investments also included AllDale I & II, both held through Cavalier Minerals. AllDale III and AllDale I & II are collectively referred to as the "AllDale Partnerships." See Note 12 – Investments for further discussion of our equity method investment in AllDale III and Note 3 – Acquisitions for discussion of the AllDale Acquisition.

We review our investments for impairment whenever events or changes in circumstances indicate a loss in the value of the investment may be other-than-temporary.

Advance Royalties**—**Rights to coal mineral leases are often acquired and/or maintained through advance royalty payments. Where royalty payments represent prepayments recoupable against future production, they are recorded as an asset, with amounts expected to be recouped within one year classified as a current asset. As mining occurs on these leases, the royalty prepayments are charged to operating expenses. We assess the recoverability of royalty prepayments based on estimated future production. Royalty prepayments estimated to be nonrecoverable are expensed. Our *Advance royalties* are summarized as follows:

	December 31,			
	2019		**2018**	
	(in thousands)			
Advance royalties, affiliates (see Note 20 – Related-Party Transactions)	$	41,216	$	32,645
Advance royalties, third-parties		12,685		11,552
Total advance royalties	$	53,901	$	44,197

Asset Retirement Obligations**—**Our coal mining operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations require, among other things, restoration of property in accordance with specified standards and an approved reclamation plan. We record a liability for the fair value of the estimated cost of future mine asset retirement and closing procedures, escalated for inflation then discounted, on a present value basis in the period incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support surface acreage for both our underground mines and past surface mines. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accounting for asset retirement obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. The depreciation is generally determined on a units-of-production basis and accretion is generally recognized over the life of the producing assets. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free interest rate. Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and are typically renewable on a yearly basis. See Note 18 – Asset Retirement Obligations for more information.

Pension Benefits**—**The funded status of our pension benefit plan is recognized separately in our consolidated balance sheets as either an asset or liability. The funded status is the difference between the fair value of plan assets and the plan's benefit obligation. Pension obligations and net periodic benefit costs are actuarially determined and impacted by various assumptions and estimates including expected return on assets, discount rates, mortality assumptions, employee turnover rates and retirement dates. We evaluate our assumptions periodically and make adjustments to these assumptions and the recorded liability as necessary (See Note 15 – Employee Benefit Plans).

The discount rate is determined for our pension benefit plan based on an approach specific to our plan. The year end discount rate is determined considering a yield curve comprised of high-quality corporate bonds and the timing of the expected benefit cash flows.

The expected long-term rate of return on plan assets is determined based on broad equity and bond indices, the investment goals and objectives, the target investment allocation and on the average annual total return for each asset class.

Unrecognized actuarial gains and losses and unrecognized prior service costs and credits are deferred and recorded in accumulated other comprehensive loss until amortized as a component of net periodic benefit cost. Unrecognized actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of plan assets are amortized over the participants' average remaining future years of service.

Workers' Compensation and Pneumoconiosis (Black Lung) Benefits—We are liable for workers' compensation benefits for traumatic injuries and benefits for black lung disease (or pneumoconiosis). Both traumatic claims and pneumoconiosis benefits are covered through our self-insured programs. In addition, certain of our mine operating entities are liable under state statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay pneumoconiosis benefits to eligible employees and former employees and their dependents.

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on our actuarial estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates.

Our pneumoconiosis benefits liability is calculated using the service cost method based on the actuarial present value of the estimated pneumoconiosis obligation. Our actuarial calculations are based on numerous assumptions including claim development patterns, medical costs and mortality. Actuarial gains or losses are amortized over the remaining service period of active miners. See Note 19 – Accrued Workers' Compensation and Pneumoconiosis Benefits for more information on Workers' Compensation and Pneumoconiosis Benefits.

Coal Revenue Recognition—Revenues from coal supply contracts with customers are recognized at the point in time when control of the coal passes to the customer. We have determined that each ton of coal represents a separate and distinct performance obligation. Our coal supply contracts and other revenue contracts vary in length from short-term to long-term contracts and do not typically have significant financing components. Transportation revenues represent the fulfillment costs incurred for the services provided to customers through third-party carriers and for which we are directly reimbursed. Other revenues primarily consist of transloading fees, administrative service revenues from our affiliates, mine safety services and products, other coal contract fees and other handling and service fees. Performance obligations under these contracts are typically satisfied upon transfer of control of the goods or services to our customer which is determined by the contract and could be upon shipment or upon delivery.

The estimated transaction price from each of our contracts is based on the total amount of consideration we expect to be entitled to under the contract. Included in the transaction price for certain coal supply contracts is the impact of variable consideration, including quality price adjustments, handling services, government imposition claims, per ton price fluctuations based on certain coal sales price indices and anticipated payments in lieu of shipments. We have constrained the expected value of variable consideration in our estimation of transaction price and only included this consideration to the extent that it is probable that a significant revenue reversal will not occur. The estimated transaction price for each contract is allocated to our performance obligations based on relative standalone selling prices determined at contract inception. Variable consideration is allocated to a specific part of the contract in many instances, such as if the variable consideration is based on production activities for coal delivered during a certain period or the outcome of a customer's ability to accept coal shipments over a certain period.

Contract assets are recorded as trade receivables and reported separately in our consolidated balance sheet from other contract assets as title passes to the customer and our right to consideration becomes unconditional. Payments for coal shipments are typically due within two to four weeks of performance. We typically do not have material contract assets that are stated separately from trade receivables as our performance obligations are satisfied as control of the goods or services passes to the customer thereby granting us an unconditional right to receive consideration. Contract liabilities relate to consideration received in advance of the satisfaction of our performance obligations. Contract liabilities are recognized as revenue at the point in time when control of the good or service passes to the customer.

Oil & Gas Revenue Recognition—Oil & gas royalty revenues are recognized at the point in time when control of the product is transferred to the purchaser by the lessee and collectability of the sales price is reasonably assured. Oil & gas are priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. The royalty we receive is tied to a market index, with certain adjustments based on, among other factors, whether a well connects to a gathering or transmission line, quality and heat content of the product, and prevailing supply and demand conditions.

We also periodically earn revenue from lease bonuses. We generate lease bonus revenue by leasing our mineral interests to exploration and production companies. A lease agreement represents our contract with an operator, which is generally an exploration and production company. The contract will a) generally transfer the rights to any oil or gas discovered, b) grant us a right to a specified royalty interest from the operator, and c) require the operator to commence drilling and complete operations within a specified time period. Control of the minerals transfers to the operator when the lease agreement is executed. At the time we execute the lease agreement, we expect to receive the lease bonus payment within a reasonable time, though in no case more than one year, such that we do not adjust the expected amount of consideration for the effects of any significant financing component.

As a non-operator, we have limited visibility into the timing of when new wells start producing, in addition, production statements may not be received for 30 to 90 days or more after the date production is delivered. As a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The expected sales volumes and prices from our properties are estimated and recorded within the *Trade receivables* line item in our consolidated balance sheets. Generally, the difference between our estimates and the actual amounts received for oil & gas royalty revenue are recorded in the month that payment is received from the third-party purchaser unless new production information is received prior to the payment allowing us to update the estimate recorded.

***Common Unit-Based Compensation*—**We have the Long-Term Incentive Plan ("LTIP") for certain employees and officers of MGP and its affiliates who perform services for us. The LTIP awards are grants of non-vested "phantom" or notional units, also referred to as "restricted units", which upon satisfaction of time and performance based vesting requirements, entitle the LTIP participant to receive ARLP common units. Annual grant levels and vesting provisions for designated participants are recommended by the Chairman, President and CEO of MGP, subject to review and approval of the compensation committee of our general partner ("Compensation Committee"). Vesting of all grants outstanding is subject to the satisfaction of certain financial tests, which management currently believes is probable. Grants issued to LTIP participants are expected to cliff vest on January 1st of the third year following issuance of the grants. We account for forfeitures of non-vested LTIP grants as they occur. We expect to settle the non-vested LTIP grants by delivery of ARLP common units, except for the portion of the grants that will satisfy tax withholding obligations of the LTIP participants. As provided under the distribution equivalent rights provisions of the LTIP and the terms of the LTIP awards, all non-vested grants include contingent rights to receive quarterly distributions in cash or, at the discretion of the Compensation Committee, phantom units in lieu of cash credited to a bookkeeping account with value equal to the cash distributions we make to unitholders during the vesting period.

We utilize the Supplemental Executive Retirement Plan ("SERP") to provide deferred compensation benefits for certain officers and key employees. All allocations made to participants under the SERP are made in the form of "phantom" ARLP units and SERP distributions will be settled in the form of ARLP common units. The SERP is administered by the Compensation Committee.

Our directors participate in the MGP Amended and Restated Deferred Compensation Plan for Directors ("Directors' Deferred Compensation Plan"). Pursuant to the Directors' Deferred Compensation Plan, for amounts deferred either automatically or at the election of the director, a notional account is established and credited with notional common units of ARLP, described in the Directors' Deferred Compensation Plan as "phantom" units. Distributions from the Directors' Deferred Compensation Plan will be settled in the form of ARLP common units.

For both the SERP and Directors' Deferred Compensation Plan, when quarterly cash distributions are made with respect to ARLP common units, an amount equal to such quarterly distribution is credited to each participant's notional account as additional phantom units. All grants of phantom units under the SERP and Directors' Deferred Compensation Plan vest immediately.

The fair value of restricted common unit grants under the LTIP, SERP and the Directors' Deferred Compensation Plan are determined on the grant date of the award and recognized as compensation expense on a pro rata basis for LTIP and SERP awards, as appropriate, over the requisite service period. Compensation expense is fully recognized on the grant date for quarterly distributions credited to SERP accounts and Directors' Deferred Compensation Plan awards. The corresponding liability is classified as equity and included in limited partners' capital in the consolidated financial statements (See Note 16 – Compensation Plans).

Income Taxes—We are not a taxable entity for federal or state income tax purposes; the tax effect of our activities accrues to the unitholders. Although publicly traded partnerships as a general rule will be taxed as corporations, we qualify for an exemption because at least 90% of our income consists of qualifying income, as defined in Section 7704(c) of the Internal Revenue Code. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. Individual unitholders have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in our consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in our partnership is not available to us. We have certain subsidiaries that are subject to federal and state income taxes. These income taxes are not material to our financial position or results of operations.

New Accounting Standards Issued and Adopted—In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, Leases (Topic 842) ("ASU 2016-02"). ASU 2016-02 requires lessees to record right-of-use assets and corresponding lease liabilities on the balance sheet and disclose key information about lease arrangements. Leases are now classified as either finance or operating, with the resulting classification affecting the pattern of expense recognition in the income statement. We elected to use the modified retrospective transition method which allows a cumulative effect adjustment on the balance sheet upon adoption. The adoption of the standard resulted in the recognition of approximately $25.0 million in additional net lease assets and respective lease liabilities as of January 1, 2019.

As part of our transition there are a number of practical expedients available in the new standard. We elected a package of practical expedients that, among other things, allows us to not reassess the lease classification of expired or existing leases. In addition to the package of practical expedients, we also elected to use a practical expedient allowing us to use hindsight in determining the lease term for existing leases.

New Accounting Standards Issued and Not Yet Adopted—In June 2016, the FASB issued ASU 2016-13, *Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments to require the use of a new forward-looking "expected loss" model that generally will result in earlier recognition of allowances for losses. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. After an analysis of our historical credit losses and development of an allowance for expected credit losses on our financial assets, we have determined the adoption of the standard will not have a material impact on our consolidated financial statements.

3. ACQUISITIONS

AllDale I & II

On the AllDale Acquisition Date, we acquired all of the limited partner interests not owned by Cavalier Minerals in AllDale I & II and the general partner interests in AllDale I & II for $176.2 million, which was funded with cash on hand and borrowings under the Revolving Credit Facility. As a result of the AllDale Acquisition and our previous investments held through Cavalier Minerals, we acquired control of approximately 43,000 net royalty acres strategically positioned primarily in the core of the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) Basins. The AllDale Acquisition provides us with diversified exposure to industry leading operators and is consistent with our general business strategy to grow our Minerals segment.

Because the underlying mineral interests held by AllDale I & II include royalty interests in both producing properties and unproved properties, we have determined that the AllDale Acquisition should be accounted for as a business combination and the underlying assets and liabilities of AllDale I & II should be recorded at their AllDale Acquisition Date fair value on our consolidated balance sheet.

The final total fair value of the cash paid in the AllDale Acquisition and our previous investments were as follows:

	As of January 3, 2019 (in thousands)
Cash	$ 176,205
Previously held investments	307,322
Total	$ 483,527

Prior to the AllDale Acquisition Date, we accounted for our investments in AllDale I & II, held through Cavalier Minerals, as equity method investments. The combined fair value of our equity method investments on the AllDale Acquisition Date was $307.3 million. We re-measured our equity method investments, which had an aggregate carrying value of $130.3 million immediately prior to the AllDale Acquisition. The re-measurement resulted in a gain of $177.0 million which is recorded in the Acquisition gain line item in our consolidated statements of income.

During the third quarter of 2019, we finalized our purchase price accounting, which resulted in adjustments to our mineral interests in proved and unproved properties due to additional information received from operators of the mineral interests about reserve and production quantities and projections that represented facts and circumstances that existed as of the AllDale Acquisition Date. In addition, we reduced our receivables by $1.3 million as a result of information received from operators concerning royalty payments owed to us from production that occurred prior to the AllDale Acquisition Date. The following table summarizes the preliminary and final fair value allocation of assets acquired and liabilities assumed as of the AllDale Acquisition Date:

	Preliminary	Adjustments (in thousands)	Final
Cash and cash equivalents	$ 900		$ 900
Mineral interests in proved properties	159,617	24,415	184,032
Mineral interests in unproved properties	314,084	(22,894)	291,190
Receivables	10,602	(1,276)	9,326
Accounts payable	(1,921)		(1,921)
Net assets acquired	$ 483,282		$ 483,527

Our previous equity method investments in AllDale I & II were held through Cavalier Minerals. Bluegrass Minerals Management, LLC ("Bluegrass Minerals") continues to hold a 4% membership interest (the "Bluegrass Interest") as well as a profits interest in Cavalier Minerals as it did before the AllDale Acquisition. This Bluegrass Interest represents an indirect noncontrolling interest in AllDale I & II. The AllDale Acquisition Date fair value of the Bluegrass Interest was $12.3 million.

The fair value of our previous equity method investments, the mineral interests and the Bluegrass Interest were determined using an income approach primarily comprised of discounted cash flow models. The assumptions used in the discounted cash flow models include estimated production, projected cash flows, forward oil & gas prices and a risk adjusted discount rate. Certain assumptions used are not observable in active markets, therefore the fair value measurements represent Level 3 fair value measurements. AllDale I & II's carrying value of the receivables and accounts payable represent their fair value given their short-term nature.

The amounts of revenue and earnings, exclusive of the acquisition gain, of AllDale I & II included in our consolidated statements of income since the AllDale Acquisition Date are as follows:

	Year Ended December 31, 2019 (in thousands)
Revenue	$ 48,411
Net income	18,543

The following represents our actual and pro forma consolidated revenues and net income for the year ended December 31, 2018. Pro forma revenues and net income assumes AllDale I & II had been included in our consolidated results since January 1, 2018. These amounts have been calculated after applying our accounting policies. Pro forma information is not necessary for the year ended December 31, 2019 as the AllDale Acquisition occurred at the beginning of the year. Additionally, our results have been adjusted to remove the effect of our past equity method investments in AllDale I & II.

		Year Ended December 31, 2018
		(in thousands)
Total revenues		
As reported	$	2,002,857
Pro forma		2,042,545
Net income		
As reported	$	367,470
Pro forma		358,741

Wing

On August 2, 2019 (the "Wing Acquisition Date"), our subsidiary, AR Midland acquired from Wing approximately 9,000 net royalty acres in the Midland Basin, with exposure to more than 400,000 gross acres, for a cash purchase price of $144.9 million. The purchase price was funded with cash on hand and borrowings under our Revolving Credit Facility discussed in Note 7 – Long-Term Debt. The Wing Acquisition enhances our ownership position in the Permian Basin, expands our exposure to industry leading operators and furthers our business strategy to grow our Minerals segment. Concurrent with the Wing Acquisition, JC Resources LP, an entity owned by Joseph W. Craft III, the Chairman, President and CEO of MGP ("Mr. Craft"), acquired from Wing, in a separate transaction, mineral interests that we elected not to acquire.

Because the mineral interests acquired in the Wing Acquisition include royalty interests in both producing properties and unproved properties, we have determined that the acquisition should be accounted for as a business combination and the underlying assets should be recorded at fair value as of the Wing Acquisition Date on our consolidated balance sheet. We consider our fair value measurements to be preliminary as we continue to obtain additional information from operators regarding reserve and production quantities and projections for the mineral interests we acquired. During the fourth quarter of 2019, we recorded adjustments to our mineral interests in proved and unproved properties due to additional information received from operators that represented facts and circumstances that existed as of the Wing Acquisition Date.

The following table summarizes the preliminary fair value allocation of assets acquired as of the Wing Acquisition Date incorporating measurement period adjustments made to the allocation:

	As Previously Reported	Adjustments	Adjusted
		(in thousands)	
Mineral interests in proved properties	$ 55,619	2,465	$ 58,084
Mineral interests in unproved properties	87,441	(2,465)	84,976
Receivables	1,867		1,867
Net assets acquired	$ 144,927		$ 144,927

The fair value of the mineral interests was determined using a weighting of both income and market approaches. Our income approach primarily comprised of a discounted cash flow model. The assumptions used in the discounted cash flow model included estimated production, projected cash flows, forward oil & gas prices and a risk-adjusted discount rate. Our market approach consisted of the observation of recent acquisitions in the Permian Basin to determine a market price for similar mineral interests. Certain assumptions used in our valuation are not observable in active markets; therefore, the fair value measurements represent Level 3 fair value measurements. The carrying value of the receivables represent their fair value given their short-term nature.

The amounts of revenue and earnings from the mineral interests acquired in the Wing Acquisition included in our consolidated statements of income since the Wing Acquisition Date are as follows:

	Year Ended December 31, 2019
	(in thousands)
Revenue	$ 4,625
Net income	1,291

The following represents our actual and pro forma consolidated revenues and net income for the years ended December 31, 2019 and 2018. Pro forma revenues and net income assumes the mineral interests acquired in the Wing Acquisition had been included in our consolidated results since January 1, 2018. These pro forma amounts have been calculated after applying our accounting policies.

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(in thousands)	
Total revenues		
As reported	$ 1,961,720	$ 2,002,857
Pro forma	1,966,291	2,008,559
Net income		
As reported	$ 406,926	$ 367,470
Pro forma	411,217	372,810

4. LONG-LIVED ASSET IMPAIRMENTS

We ceased coal production effective August 16, 2019 at our Dotiki mine to focus on shifting production to our other lower-cost mines in our Illinois Basin segment. Accordingly, we adjusted the carrying value of Dotiki's assets from $35.9 million to its fair value of $25.8 million and accrued scheduled payments of $5.1 million to WKY CoalPlay for leased reserves from which we may not receive future economic benefit. The resulting impairment charge totaled $15.2 million. See Note 11 – Variable Interest Entities for more information about WKY CoalPlay. Previously, in the fourth quarter of 2018, we reduced Dotiki’s economic mine life which resulted in a $34.3 million impairment charge, and the related adjustment of Dotiki’s asset carrying value from $85.3 million to its fair value of $51.0 million. Also in the fourth quarter of 2018, a decrease in the fair value of an option entitling us to lease certain coal reserves within the Illinois Basin Segment resulted in an impairment charge of $6.2 million.

The fair value of the impaired assets was determined using a combination of market and income approaches, both of which represent Level 3 fair value measurements under the fair value hierarchy. The fair value analysis used assumptions of marketability of certain assets as well as discounted cash flows over the remaining life of the assets.

See Note 2 – Summary of Significant Accounting Policies – Long-Lived Asset Impairment for more information on our accounting policy for asset impairments.

5. INVENTORIES

Inventories consist of the following**:**

	December 31,			
	2019		2018	
	(in thousands)			
Coal	$	63,645	$	20,929
Supplies (net of reserve for obsolescence of $5,555 and $5,453, respectively)		37,660		38,277
Total inventories, net	$	101,305	$	59,206

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for inventories.

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following:

	December 31,			
	2019		2018	
	(in thousands)			
Mining equipment and processing facilities	$	1,937,642	$	1,851,479
Land and coal mineral rights		453,237		445,411
Oil & gas mineral interests (1)		618,282		—
Buildings, office equipment and improvements		304,111		287,053
Construction and mine development in progress		86,876		71,190
Mine development costs		283,860		270,675
Property, plant and equipment, at cost		3,684,008		2,925,808
Less accumulated depreciation, depletion and amortization		(1,675,022)		(1,513,450)
Total property, plant and equipment, net	$	2,008,986	$	1,412,358

(1) Oil & gas mineral interests acquired in the AllDale and Wing Acquisitions. See Note 3 – Acquisitions for more information.

At December 31, 2019 and 2018, land and coal mineral rights above include $40.1 million and $49.2 million, respectively, of carrying value associated with coal reserves attributable to properties where we or a third party to which we lease reserves are not currently engaged in mining operations or leasing to third parties, and therefore, the coal reserves are not currently being depleted. We believe that the carrying value of these coal reserves will be recovered.

At December 31, 2019, our oil & gas mineral interests noted in the table above includes the carrying value of our unproved oil & gas mineral interests totaling $376.2 million. As discussed in Note 2 – Summary of Significant Accounting Policies, we generally do not record depletion expense for our unproved oil & gas mineral interests; however, we do review for impairment as needed throughout the year.

During 2019, we incurred $13.2 million in mine development costs, primarily related to the development of our Excel #5 mine at our MC Mining complex. During 2018, we reduced mine development costs by $9.9 million primarily related to the impairment of our Dotiki mine. Regarding the mine development costs for MC Mining's Excel #5 mine, we had no incidental production during this development phase and thus no related capitalized development costs associated with incidental production. All past capitalized mine development costs are associated with other mines that shifted to the production phase in past years and we are amortizing these costs accordingly. We believe that the carrying value of the past development costs will be recovered. For information regarding long-lived asset impairments please see Note 4 – Long-Lived Asset Impairments.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for property, plant and equipment.

7. LONG-TERM DEBT

Long-term debt consists of the following:

	Principal		Unamortized Discount and Debt Issuance Costs	
	December 31,		December 31,	
	2019	2018	2019	2018
	(in thousands)			
Revolving credit facility	$ 255,000	$ 175,000	$ (3,050)	$ (5,203)
Senior notes	400,000	400,000	(4,879)	(5,793)
Securitization facility	73,800	92,000	—	—
May 2019 equipment financing	8,199	—	—	—
November 2019 equipment financing	52,281	—	—	—
	789,280	667,000	(7,929)	(10,996)
Less current maturities	(13,157)	(92,000)	—	—
Total long-term debt	$ 776,123	$ 575,000	$ (7,929)	$ (10,996)

Credit Facility. On January 27, 2017, our Intermediate Partnership entered into a Fourth Amended and Restated Credit Agreement (the "Credit Agreement") with various financial institutions. The Credit Agreement provides for a $494.75 million revolving credit facility, including a sublimit of $125 million for the issuance of letters of credit and a sublimit of $15.0 million for swingline borrowings (the "Revolving Credit Facility"), with a termination date of May 23, 2021. We incurred debt issuance costs in 2017 of $9.2 million in connection with the Credit Agreement. These debt issuance costs are deferred and amortized as a component of interest expense over the term of the Revolving Credit Facility.

The Credit Agreement is guaranteed by all of the material direct and indirect subsidiaries of our Intermediate Partnership, and is secured by substantially all of the Intermediate Partnership's assets. Borrowings under the Revolving Credit Facility bear interest, at the option of the Intermediate Partnership, at either (i) the Base Rate at the greater of three benchmarks or (ii) a Eurodollar Rate, plus margins for (i) or (ii), as applicable, that fluctuate depending upon the ratio of Consolidated Debt to Consolidated Cash Flow (each as defined in the Credit Agreement). The Eurodollar Rate, with applicable margin, under the Revolving Credit Facility was 4.32% as of December 31, 2019. At December 31, 2019, we had $9.3 million of letters of credit outstanding with $230.5 million available for borrowing under the Revolving Credit Facility. We currently incur an annual commitment fee of 0.35% on the undrawn portion of the Revolving Credit Facility. We utilize the Revolving Credit Facility, as appropriate, for working capital requirements, capital expenditures and investments, scheduled debt payments and distribution payments.

The Credit Agreement contains various restrictions affecting our Intermediate Partnership and its subsidiaries including, among other things, restrictions on incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates, in each case subject to various exceptions, and the payment of cash distributions by our Intermediate Partnership if such payment would result in a certain fixed charge coverage ratio (as defined in the Credit Agreement). The Credit Agreement requires the Intermediate Partnership to maintain (a) a debt to cash flow ratio of not more than 2.5 to 1.0 and (b) a cash flow to interest expense ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt to cash flow ratio and cash flow to interest expense ratio were 1.34 to 1.0 and 12.6 to 1.0, respectively, for the trailing twelve months ended December 31, 2019. We remain in compliance with the covenants of the Credit Agreement as of December 31, 2019.

Senior Notes. On April 24, 2017, the Intermediate Partnership and Alliance Resource Finance Corporation ("Alliance Finance") (as co-issuer), a wholly owned subsidiary of the Intermediate Partnership, issued an aggregate principal amount of $400.0 million of senior unsecured notes due 2025 ("Senior Notes") in a private placement to qualified institutional buyers. The Senior Notes have a term of eight years, maturing on May 1, 2025 (the "Term") and accrue interest at an annual rate of 7.5%. Interest is payable semi-annually in arrears on each May 1 and November 1. The indenture governing the Senior Notes contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of distributions or similar restricted payments, undertaking transactions with affiliates and limitations on asset sales. At any time prior to May 1, 2020, the issuers of the Senior Notes may redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price equal to 107.5% of the principal amount redeemed, plus accrued and unpaid interest, if any, to the redemption date. The issuers of the Senior Notes may also redeem all or a part of the notes at any time on or after May 1, 2020, at redemption prices set forth in the indenture governing the Senior Notes. At any time prior to May 1, 2020, the issuers of the Senior Notes may redeem the Senior Notes at a redemption price equal to the principal amount of the Senior Notes plus a "make-whole" premium, plus accrued and unpaid interest, if any, to the redemption date. The net proceeds from issuance of the Senior Notes and cash on hand were used to repay previous debt obligations (including a make-whole payment of $8.1 million). We incurred discount and debt issuance costs of $7.3 million in connection with issuance of the Senior Notes. These costs are deferred and are currently being amortized as a component of interest expense over the Term.

Accounts Receivable Securitization. On December 5, 2014, certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership entered into a $100.0 million accounts receivable securitization facility ("Securitization Facility"). Under the Securitization Facility, certain subsidiaries sell trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, LLC ("AROP Funding"), a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to $100.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a Eurodollar Rate. In January 2019, we extended the term of the Securitization Facility to January 2020. In October 2019, we extended the term from January 2020 to January 2021. At December 31, 2019, we had $73.8 million outstanding under the Securitization Facility.

May 2019 Equipment Financing. On May 17, 2019, the Intermediate Partnership entered into an equipment financing arrangement accounted for as debt, wherein the Intermediate Partnership received $10.0 million in exchange for conveying its interest in certain equipment owned indirectly by the Intermediate Partnership and entering into a master lease agreement for that equipment (the "May 2019 Equipment Financing"). The May 2019 Equipment Financing contains customary terms and events of default and provides for thirty-six monthly payments with an implicit interest rate of 6.25%, maturing on May 1, 2022. Upon maturity, the equipment will revert back to the Intermediate Partnership.

November 2019 Equipment Financing. On November 6, 2019, the Intermediate Partnership entered into an equipment financing arrangement accounted for as debt, wherein the Intermediate Partnership received $53.1 million in exchange for conveying its interest in certain equipment owned indirectly by the Intermediate Partnership and entering into a master lease agreement for that equipment (the "November 2019 Equipment Financing"). The November 2019 Equipment Financing contains an implicit interest rate of 4.75% and provides for a four year term with forty-seven monthly payments of $1.0 million and a balloon payment of $11.6 million upon maturity on November 6, 2023. At maturity, the equipment will revert back to the Intermediate Partnership. The November 2019 Equipment Financing contains customary terms and events of default.

Other. We also have an agreement with a bank to provide additional letters of credit in an amount of $5.0 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers' compensation benefits. At December 31, 2019, we had $5.0 million in letters of credit outstanding under this agreement.

Aggregate maturities of long-term debt are payable as follows:

Year Ended December 31,	(in thousands)
2020	$ 13,157
2021	342,648
2022	12,403
2023	21,072
2024	—
Thereafter	400,000
	$ 789,280

8. LEASES

The components of lease expense were as follows:

	December 31, 2019 (in thousands)
Finance lease cost:	
Amortization of right-of-use assets	$ 14,608
Interest on lease liabilities	2,085
Operating lease cost	9,169
Short-term lease cost	464
Variable lease cost	1,360
Total lease cost	$ 27,686

Rental expense was $11.0 million, $14.9 million and $16.0 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Supplemental cash flow information related to leases was as follows:

	December 31, 2019 (in thousands)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows for operating leases	$ 9,124
Operating cash flows for finance leases	$ 891
Financing cash flows for finance leases	$ 46,725
Right-of-use assets obtained in exchange for lease obligations:	
Operating leases	$ 25,593

Supplemental balance sheet information related to leases was as follows:

	December 31, 2019	December 31, 2018
	(in thousands)	
Finance leases:		
Property and equipment finance lease assets, gross	$ 30,610	$ 141,019
Accumulated depreciation	(20,564)	(74,576)
Property and equipment finance lease assets, net	$ 10,046	$ 66,443

	December 31, 2019
Weighted average remaining lease term	
Operating leases	13.1 years
Finance leases	1.6 years
Weighted average discount rate	
Operating leases	6.0 %
Finance leases	6.0 %

Maturities of lease liabilities as of December 31, 2019 were as follows:

	Operating leases	Finance leases
	(in thousands)	
2020	$ 3,832	$ 8,747
2021	2,280	912
2022	2,217	912
2023	2,040	139
2024	1,820	139
Thereafter	13,539	419
Total lease payments	25,728	11,268
Less imputed interest	(8,161)	(676)
Total	$ 17,567	$ 10,592

9. FAIR VALUE MEASUREMENTS

The following table summarizes our fair value measurements within the hierarchy not included elsewhere in these notes:

	December 31, 2019			December 31, 2018		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in thousands)					
Long-term debt	$ —	$ 736,206	$ —	$ —	$ 669,864	$ —
Total	$ —	$ 736,206	$ —	$ —	$ 669,864	$ —

See Note 2 – Summary of Significant Accounting Policies – Fair Value Measurements for more information regarding fair value hierarchy levels.

The carrying amounts for cash equivalents, accounts receivable, accounts payable, accrued and other liabilities, due from affiliates and due to affiliates approximate fair value due to the short maturity of those instruments.

The estimated fair value of our long-term debt, including current maturities, is based on interest rates that we believe are currently available to us in active markets for issuance of debt with similar terms and remaining maturities (See Note 7 – Long-Term Debt). The fair value of debt, which is based upon these interest rates, is classified as a Level 2 measurement under the fair value hierarchy.

10. PARTNERS' CAPITAL

Distributions

We distribute 100% of our available cash that is not used for unit repurchases within 45 days after the end of each quarter to unitholders of record. Available cash is generally defined in the partnership agreement as all cash and cash equivalents on hand at the end of each quarter less reserves established by MGP in its reasonable discretion for future cash requirements. These reserves are retained to provide for the conduct of our business, the payment of debt principal and interest and to provide funds for future distributions.

Prior to the Exchange Transaction in July 2017 (See Note 1 – Organization and Presentation – Partnership Simplification), as quarterly distributions of available cash exceeded certain target distribution levels, MGP received incentive distributions based on specified increasing percentages of the available cash that exceeded the target distribution levels. MGP was entitled to receive 15% of the amount we distributed in excess of $0.1375 per unit, 25% of the amount we distributed in excess of $0.15625 per unit, and 50% of the amount we distributed in excess of $0.1875 per unit. During the year ended December 31, 2017, we paid to MGP incentive distributions of $37.6 million. Beginning with distributions paid in the third quarter of 2017, we no longer make distributions with respect to the IDRs. The following table summarizes the quarterly per unit distribution paid during the respective quarter:

	Year Ended December 31,		
	2019	2018	2017
First Quarter	$ 0.5300	$ 0.5100	$ 0.4375
Second Quarter	$ 0.5350	$ 0.5150	$ 0.4375
Third Quarter	$ 0.5400	$ 0.5200	$ 0.5000
Fourth Quarter	$ 0.5400	$ 0.5250	$ 0.5050

On January 27, 2020, we declared a quarterly distribution of $0.40 per unit, totaling approximately $50.8 million, on all our common units outstanding, which was paid on February 14, 2020, to all unitholders of record on February 7, 2020.

Exchange Transaction

On July 28, 2017, as part of the Exchange Transaction discussed in Note 1 – Organization and Presentation – Partnership Simplification, MGP contributed to ARLP all of its IDRs and its 0.99% managing general partner interest in ARLP in exchange for 56,100,000 ARLP common units and a non-economic general partner interest in ARLP. In conjunction with this transaction and on the same economic basis as MGP, SGP also contributed to ARLP its 0.01% general partner interests in both ARLP and the Intermediate Partnership in exchange for 28,141 ARLP common units.

The Exchange Transaction constituted an exchange of equity interests between entities under common control and not a transfer of a business. Therefore, the exchange resulted in a reclassification, as of the date of the Exchange Transaction, of a $306.7 million deficit capital balance from the *General Partners' interest* line item to the *Limited Partners - Common Unitholders* line item in our consolidated balance sheets. The reclassification amounts represented the carrying value of the exchanged interests, which included the SGP's deficit balance associated with its prior special general partner interests in ARLP and the Intermediate Partnership, partially offset, by MGP's capital balance associated with its prior managing general partner interest in ARLP. The SGP deficit balance primarily resulted from contribution and assumption agreements associated with the formation of the ARLP Partnership in 1999.

Simplification Transactions

On May 31, 2018, as part of the Simplification Transactions discussed in Note 1 – Organization and Presentation, ARLP issued 1,322,388 ARLP common units to the Owners of SGP in exchange for causing SGP to contribute to ARLP all of SGP's limited partner interests in AHGP, which included AHGP's indirect ownership of a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal.

The Simplification Transactions are accounted for prospectively as an exchange of equity interests between entities under common control. Since ARLP and AHGP were under common control both before and after the Simplification Transactions, no fair value adjustment was made to the assets or liabilities of AHGP and its subsidiaries and no gain or loss was recognized on our consolidated financial statements.

Unit Repurchase Program

In May 2018, the Board of Directors approved the establishment of a unit repurchase program authorizing us to repurchase and retire up to $100 million of ARLP common units. The program has no time limit and we may repurchase units from time to time in the open market or in other privately negotiated transactions. The unit repurchase program authorization does not obligate us to repurchase any dollar amount or number of units. As of December 31, 2019, we had repurchased and retired 5,460,639 units at an average unit price of $17.12 for an aggregate purchase price of $93.5 million. Total units repurchased includes the repurchase and retirement of 35 units representing fractional units as part of the Simplification Transactions which are not part of the unit repurchase program.

Affiliated Entity Contributions

An affiliated entity controlled by Mr. Craft made capital contributions of $2.1 million and $1.0 million during the years ended December 31, 2018 and 2017, respectively, for the purpose of funding certain general and administrative expenses. On June 29, 2018, the members of this affiliated entity contributed 467,018 ARLP common units for similar purposes.

Other

The noncontrolling interest in our consolidated balance sheets represents Bluegrass Minerals' ownership interest in Cavalier Minerals. Our accumulated other comprehensive loss consists of unrecognized actuarial gains and losses as well as unrecognized prior service costs related to our pension and pneumoconiosis benefits. See Note 11 – Variable Interest Entities, Note 15 –Employee Benefit Plans and Note 19 – Accrued Workers' Compensation and Pneumoconiosis Benefits for further information.

11. VARIABLE INTEREST ENTITIES

Cavalier Minerals

On November 10, 2014, our subsidiary, Alliance Minerals, and Bluegrass Minerals entered into a limited liability company agreement (the "Cavalier Agreement") to create Cavalier Minerals, which was formed to indirectly acquire oil & gas mineral interests through its ownership in AllDale I & II. Alliance Minerals owns a 96% membership interest in Cavalier Minerals, and Bluegrass Minerals owns a 4% membership interest in Cavalier Minerals and a profits interest which entitles it to receive distributions equal to 25% of all distributions (including in liquidation) after all members have recovered their investment. Distributions with respect to Bluegrass Minerals' profits interest will be offset by all distributions received by Bluegrass Minerals from the former general partners of AllDale I & II. To date, there has been no profits interest distributions. Bluegrass Minerals was Cavalier Minerals' managing member prior to the AllDale Acquisition (see Note 3 – Acquisitions). In conjunction with the AllDale Acquisition, we became the managing member in Cavalier Minerals. Total contributions to and cumulative distributions from Cavalier Minerals are as follows:

	Alliance Minerals	Bluegrass Minerals
	(in thousands)	
Contributions	$ 143,112	$ 5,963
Distributions	71,916	2,996

We have concluded that Cavalier Minerals is a VIE which we consolidate as the primary beneficiary because we are the managing member and a substantial equity owner in Cavalier Minerals. Bluegrass Minerals' equity ownership of Cavalier Minerals is accounted for as noncontrolling ownership interest in our consolidated balance sheets. In addition, earnings attributable to Bluegrass Minerals are recognized as noncontrolling interest in our consolidated statements of income.

AllDale III

In February 2017, Alliance Minerals committed to directly invest $30.0 million in AllDale III which was created for similar investment purposes as AllDale I & II. Alliance Minerals completed funding of this commitment in 2018. Alliance Minerals' limited partner interest in AllDale III at December 31, 2019 was 13.9%.

The AllDale III Partnership Agreement includes a 25% profits interest for the general partner, subject to a return hurdle equal to the greater of 125% of cumulative capital contributions and a 10% internal rate of return, and following an 80/20 "catch-up" provision for the general partner.

Since AllDale III is structured as a limited partnership with the limited partners 1) not having the ability to remove the general partner and 2) not participating significantly in the operational decisions, we concluded that AllDale III is a VIE. We are not the primary beneficiary of AllDale III as we do not have the power to direct the activities that most significantly impact AllDale III's economic performance. We account for our ownership interest in the income or loss of AllDale III as an equity method investment. We record equity income or loss based on AllDale III's distribution structure. See Note 12 – Investments for more information.

WKY CoalPlay

On November 17, 2014, SGP Land, LLC ("SGP Land"), a wholly owned subsidiary of SGP, and two limited liability companies ("Craft Companies") owned by irrevocable trusts established by the Chairman, President and CEO of MGP and his children entered into a limited liability company agreement to form WKY CoalPlay, LLC ("WKY CoalPlay"). WKY

CoalPlay was formed, in part, to purchase and lease coal reserves. WKY CoalPlay is managed by an individual who is an officer and director of Alliance Resource Holdings II, Inc. ("ARH II") and trustee of the irrevocable trusts owning one of the Craft Companies. In December 2014 and February 2015, we entered into various coal reserve leases with WKY CoalPlay. See Note 20 – Related-Party Transactions for further information on our lease terms with WKY CoalPlay.

We have concluded that WKY CoalPlay is a VIE because of our ability to exercise options to acquire reserves under lease with WKY CoalPlay (Note 20 – Related-Party Transactions), which is not within the control of the equity holders and, if it occurs, could potentially limit the expected residual return to the owners of WKY CoalPlay. We do not have any economic or governance rights related to WKY CoalPlay and our options that provide us with a variable interest in WKY CoalPlay's reserve assets do not give us any rights that constitute power to direct the primary activities that most significantly impact WKY CoalPlay's economic performance. SGP Land has the sole ability to replace the manager of WKY CoalPlay at its discretion and therefore has power to direct the activities of WKY CoalPlay. Consequently, we concluded that SGP Land is the primary beneficiary of WKY CoalPlay.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for variable interest entities.

12. INVESTMENTS

AllDale III

As discussed in Note 11 – Variable Interest Entities, we account for our ownership interest in the income or loss of AllDale III as an equity method investment. We record equity income or loss based on AllDale III's distribution structure. The changes in our equity method investment in AllDale III for each of the periods presented were as follows:

	Year Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Beginning balance	$ 28,974	$ 14,182	$ —
Contributions	—	15,600	14,400
Equity method investment income (loss)	2,203	547	(218)
Distributions received	(2,648)	(1,355)	—
Ending balance	$ 28,529	$ 28,974	$ 14,182

Kodiak

On July 19, 2017, Alliance Minerals purchased $100 million of Series A-1 Preferred Interests from Kodiak, a privately-held company providing large-scale, high-utilization gas compression assets to customers operating primarily in the Permian Basin. This structured investment provided us with a quarterly cash or payment-in-kind return. On February 8, 2019, Kodiak redeemed our preferred interest for $135.0 million in cash resulting in an $11.5 million gain due to an early redemption premium. The gain is included in the *Equity securities income* line item. We no longer hold any ownership interests in Kodiak. Prior to the redemption, we accounted for our ownership interests in Kodiak as equity securities without readily determinable fair values.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for investments.

13. REVENUE FROM CONTRACTS WITH CUSTOMERS

The following table illustrates the disaggregation of our revenues by type, including a reconciliation to our segment presentation as presented in Note 23 – Segment Information.

	Illinois Basin	Appalachia	Minerals	Other and Corporate	Elimination	Consolidated
				(in thousands)		
Year Ended December 31, 2019						
Coal sales	$ 1,128,588	$ 628,406	$ —	$ 22,138	$ (16,690)	$ 1,762,442
Oil & gas royalties	—	—	51,735	—	—	51,735
Transportation revenues	94,686	4,817	—	—	—	99,503
Other revenues	13,034	11,166	1,301	34,712	(12,173)	48,040
Total revenues	$ 1,236,308	$ 644,389	$ 53,036	$ 56,850	$ (28,863)	$ 1,961,720
Year Ended December 31, 2018						
Coal sales	$ 1,197,143	$ 635,530	$ —	$ 43,393	$ (31,258)	$ 1,844,808
Transportation revenues	106,947	5,435	—	3	—	112,385
Other revenues	16,999	3,000	—	38,096	(12,431)	45,664
Total revenues	$ 1,321,089	$ 643,965	$ —	$ 81,492	$ (43,689)	$ 2,002,857
Year Ended December 31, 2017						
Coal sales	$ 1,078,255	$ 616,305	$ —	$ 74,973	$ (58,419)	$ 1,711,114
Transportation revenues	35,585	6,115	—	—	—	41,700
Other revenues	12,024	3,621	—	39,776	(12,015)	43,406
Total revenues	$ 1,125,864	$ 626,041	$ —	$ 114,749	$ (70,434)	$ 1,796,220

The following table illustrates the amount of our transaction price for all current coal supply contracts allocated to performance obligations that are unsatisfied or partially unsatisfied as of December 31, 2019 and disaggregated by segment and contract duration.

	2020	2021	2022	2023 and Thereafter	Total
			(in thousands)		
Illinois Basin coal revenues	$ 849,040	$ 437,808	$ 34,414	$ 8,470	$ 1,329,732
Appalachia coal revenues	426,162	97,729	54,132	—	578,023
Total coal revenues (1)	$ 1,275,202	$ 535,537	$ 88,546	$ 8,470	$ 1,907,755

(1) Coal revenues generally consists of consolidated revenues excluding our Minerals segment.

14. EARNINGS PER LIMITED PARTNER UNIT

We utilize the two-class method in calculating basic and diluted earnings per limited partner unit ("EPU"). Subsequent to the Simplification Transactions, net income attributable to ARLP is only allocated to limited partners and participating securities under deferred compensation plans. Prior to the Simplification Transactions, net income attributable to ARLP was allocated to the general partners, limited partners and participating securities under deferred compensation plans in accordance with their respective partnership ownership percentages, after giving effect to any special income or expense allocations. Prior to the Exchange Transaction, net income attributable to ARLP was also allocated to our general partner, MGP, for incentive distributions. Please see Note 1 – Organization and Presentation for more information on the Simplification Transactions and the Exchange Transaction.

Our participating securities under deferred compensation plans include rights to nonforfeitable distributions or distribution equivalents. Our participating securities are outstanding awards under our LTIP and phantom units in notional accounts under our SERP and the Directors' Deferred Compensation Plan.

In connection with the Exchange Transaction, ARLP amended its partnership agreement to reflect, among other things, cancellation of the IDRs and the economic general partner interest in ARLP and issuance of a non-economic general partner interest to MGP. The IDR provisions of our partnership agreement prior to the Exchange Transaction are outlined in Note 10 – Partners' Capital. Beginning with distributions declared for the three months ended June 30, 2017, we no longer make distributions with respect to the IDRs.

As a result of the Simplification Transactions, MGP no longer holds economic interests in the Intermediate Partnership or Alliance Coal. We no longer make distributions or allocate income and losses to MGP in our calculation of EPU.

The following is a reconciliation of net income attributable to ARLP used for calculating basic and diluted earnings per unit and the weighted-average units used in computing EPU.

	Year Ended December 31,		
	2019	**2018**	**2017**
	(in thousands, except per unit data)		
Net income attributable to ARLP	$ 399,414	$ 366,604	$ 303,638
Adjustments:			
MGP's priority distributions (1)	—	—	(19,216)
General partners' equity ownership (1)	—	(1,560)	(3,688)
General partner's special allocation of certain general and administrative expenses (2)	—	—	1,000
Limited partners' interest in net income attributable to ARLP	399,414	365,044	281,734
Less:			
Distributions to participating securities	(4,254)	(5,114)	(4,339)
Undistributed earnings attributable to participating securities	(2,237)	(1,641)	(1,026)
Net income attributable to ARLP available to limited partners	$ 392,923	$ 358,289	$ 276,369
Weighted-average limited partner units outstanding – basic and diluted	128,117	130,758	98,708
Earnings per limited partner unit - basic and diluted (3)	$ 3.07	$ 2.74	$ 2.80

(1) Amounts for 2019 and 2018 reflect the impact of the Simplification Transactions which ended net income allocations and quarterly cash distributions to MGP after May 31, 2018. Amounts for 2017 reflect the impact of the Exchange Transaction ending distributions that would have been paid for the IDRs and a 0.99% general partner interest in ARLP, both of which were held by MGP prior to the 2017 Exchange Transaction. For the time period between the Exchange Transaction and the Simplification Transactions, MGP maintained a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal and thus received quarterly distributions and income and loss allocations during this time period. The SGP had a nominal general partner interest prior to the Exchange Transaction.

(2) MGP made a capital contribution of $1.0 million during 2017 to Alliance Coal for the purpose of funding certain general and administrative expenses. As provided under our partnership agreement, we made a special allocation to MGP of certain general and administrative expenses equal to its contribution. Net income attributable to ARLP allocated to the limited partners was not burdened by this expense. See Note 10 – Partners' Capital for more information regarding this contribution.

(3) Diluted EPU gives effect to all potentially dilutive common units outstanding during the period using the treasury stock method. Diluted EPU excludes all potentially dilutive units calculated under the treasury stock method if their effect is anti-dilutive. For the years ended December 31, 2019, 2018 and 2017, the combined total of LTIP, SERP and Directors' Deferred Compensation Plan units of 1,284,013, 1,658,908 and 1,466,404, respectively, were considered anti-dilutive under the treasury stock method.

On a pro forma basis, as if the Exchange Transaction and the Simplification Transactions had taken place on January 1, 2017, the reconciliation of net income attributable to ARLP to basic and diluted earnings per unit and the weighted-average units used in computing EPU are as follows:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands, except per unit data)		
Net income attributable to ARLP	$ 399,414	$ 366,604	$ 303,638
Pro forma adjustments (1)	—	(1,265)	(1,943)
Pro forma net income of ARLP	399,414	365,339	301,695
Less:			
Distributions to participating securities	(4,254)	(5,114)	(4,339)
Undistributed earnings attributable to participating securities	(2,237)	(1,627)	(680)
Net income attributable to ARLP available to limited partners (2)	$ 392,923	$ 358,598	$ 296,676
Weighted-average limited partner units outstanding – basic and diluted (2)	128,117	131,310	132,024
Pro forma earnings per limited partner unit - basic and diluted (3)	$ 3.07	$ 2.73	$ 2.25

(1) Pro forma adjustments to net income attributable to ARLP primarily represent the elimination of administrative service revenues from AHGP and the inclusion of general and administrative expenses incurred at AHGP.

(2) Net income attributable to ARLP available to limited partners reflects net income allocations made for all periods presented based on the ownership structure subsequent to the Simplification Transactions. Accordingly, no general partner income allocations are presented above. Pro forma amounts above also reflect weighted average units outstanding as if the issuance of 56,128,141 ARLP common units in the Exchange Transaction and 1,322,388 ARLP common units in the Simplification Transactions applied to all periods presented.

(3) Diluted EPU gives effect to all potentially dilutive common units outstanding during the period using the treasury stock method. Diluted EPU excludes all potentially dilutive units calculated under the treasury stock method if their effect is anti-dilutive. For the years ended December 31, 2019, 2018 and 2017, the combined total of LTIP, SERP and Directors' Deferred Compensation Plan units of 1,284,013, 1,658,908 and 1,466,404, respectively, were considered anti-dilutive under the treasury stock method.

15. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans—Eligible employees currently participate in a defined contribution profit sharing and savings plan ("PSSP") that we sponsor. The PSSP covers all regular full-time employees. PSSP participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. We make matching contributions based on a percent of an employee's eligible compensation and also make an additional non-matching contribution. Our contribution expense for the PSSP was approximately $21.1 million, $19.9 million and $18.7 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Defined Benefit Plan—Eligible employees and former employees of certain of our mining operations participate in a defined benefit plan (the "Pension Plan") that we sponsor. The Pension Plan is closed to new applicants. Participants in the Pension Plan are no longer receiving benefit accruals for service. Participants can participate in enhanced benefits provisions under the PSSP. The benefit formula for the Pension Plan is a fixed-dollar unit based on years of service.

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2019 and 2018 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements:

	December 31,	
	2019	2018
	(dollars in thousands)	
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 118,958	$ 127,298
Interest cost	4,864	4,462
Actuarial loss (gain)	17,084	(8,562)
Benefits paid	(4,481)	(4,240)
Benefit obligations at end of year	136,425	118,958
Change in plan assets:		
Fair value of plan assets at beginning of year	75,823	81,981
Employer contribution	5,559	4,187
Actual return on plan assets	14,666	(6,105)
Benefits paid	(4,481)	(4,240)
Fair value of plan assets at end of year	91,567	75,823
Funded status at the end of year	$ (44,858)	$ (43,135)
Amounts recognized in balance sheet:		
Non-current liability	$ (44,858)	$ (43,135)
Amounts recognized in accumulated other comprehensive income consists of:		
Prior service cost	$ (940)	$ (1,126)
Net actuarial loss	(45,125)	(41,697)
	$ (46,065)	$ (42,823)
Weighted-average assumption to determine benefit obligations as of December 31,		
Discount rate	3.15%	4.17%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,		
Discount rate	4.17%	3.54%
Expected return on plan assets	6.50%	7.00%

The actuarial loss component of the change in benefit obligation in 2019 was primarily attributable to a decrease in the discount rate compared to December 31, 2018, offset in part by updated mortality tables. The actuarial gain component of the change in benefit obligation in 2018 was primarily attributable to an increase in the discount rate compared to December 31, 2017 and updated mortality tables, offset in part by decreases in expected retirements and other demographic changes.

The expected long-term rate of return used to determine our pension liability is based on a 1.5% active management premium in addition to an asset allocation assumption of:

As of December 31, 2019	Asset allocation assumption
Equity securities	62%
Fixed income securities	33%
Real estate	5%
	100%

The actual return on plan assets was 19.2% and a loss of 6.7% for the years ended December 31, 2019 and 2018, respectively.

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Components of net periodic benefit cost:			
Interest cost	$ 4,864	$ 4,462	$ 4,587
Expected return on plan assets	(4,932)	(5,784)	(4,978)
Amortization of prior service cost	186	186	186
Amortization of net loss	3,922	3,608	3,054
Net periodic benefit cost (1)	$ 4,040	$ 2,472	$ 2,849

(1) Nonservice components of net periodic benefit cost are included in the *Other income (expense)* line item within our consolidated statements of income (see Note 2 – Summary of Significant Accounting Policies).

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive loss:		
Net actuarial loss	$ (7,350)	$ (3,326)
Reversal of amortization item:		
Prior service cost	186	186
Net actuarial loss	3,922	3,608
Total recognized in accumulated other comprehensive loss	(3,242)	468
Net periodic benefit cost	(4,040)	(2,472)
Total recognized in net periodic benefit cost and accumulated other comprehensive loss	$ (7,282)	$ (2,004)

Estimated future benefit payments as of December 31, 2019 are as follows:

Year Ended December 31,	(in thousands)
2020	$ 5,288
2021	5,677
2022	6,045
2023	6,342
2024	6,507
2025-2029	34,755
	$ 64,614

We expect to contribute $5.3 million to the Pension Plan in 2020.

The Compensation Committee has appointed an investment manager with full investment authority with respect to Pension Plan investments subject to investment guidelines and compliance with ERISA or other applicable laws. The investment manager employs a series of asset allocation strategy phases to glide the portfolio risk commensurate with both plan characteristics and market conditions. The objective of the allocation policy is to reach and maintain fully funded status. The total portfolio allocation will be adjusted as the funded ratio of the Pension Plan changes and market conditions warrant. The target allocation includes investments in equity and fixed income commingled investment funds. Total account performance is reviewed at least annually, using a dynamic benchmark approach to track investment performance. General asset allocation guidelines at December 31, 2019 are as follows:

	Percentage of Total Portfolio		
	Minimum	**Target**	**Maximum**
Equity securities	45%	62%	80%
Fixed income securities	10%	33%	55%
Real estate	0%	5%	10%

Equity securities include domestic equity securities, developed international securities, emerging markets equity securities and real estate investment trust. Fixed income securities include domestic and international investment grade fixed income securities, high yield securities and emerging markets fixed income securities. Fixed income futures may also be utilized within the fixed income securities asset allocation.

The following information discloses the fair values of our Pension Plan assets by asset category:

	December 31,	
	2019	**2018**
	(in thousands)	
Cash and cash equivalents (a)	$ 2,958	$ 5,277
Commingled investment funds measured at net asset value (b):		
Equities - Global	10,028	—
Equities - United States large-cap	19,220	21,862
Equities - United States small-cap	7,592	5,259
Equities - International developed markets	10,528	10,593
Equities - International emerging markets	8,410	4,808
Fixed income - Investment grade	26,186	15,777
Fixed income - High yield	—	4,508
Real estate	4,355	5,034
Other	2,290	2,705
Total	$ 91,567	$ 75,823

(a) Cash and cash equivalents represents a Level 1 fair value measurement. See Note 2 – Summary of Significant Accounting Policies – Fair Value Measurements for more information regarding the definitions of fair value hierarchy levels.

(b) Investments measured at fair value using the net asset value per share (or its equivalent) have not been classified within the fair value hierarchy. The fair values of all commingled investment funds are determined based on the net asset values per unit of each of the funds. The net asset values per unit represent the aggregate value of the fund's assets at fair value less liabilities, divided by the number of units outstanding.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for pension benefits.

16. COMPENSATION PLANS

Long-Term Incentive Plan

We maintain the LTIP for certain employees and officers of MGP and its affiliates who perform services for us. The LTIP awards are grants of non-vested "phantom" or notional units, also referred to as "restricted units", which upon satisfaction of time and performance-based vesting requirements, entitle the LTIP participant to receive ARLP common units. Annual grant levels and vesting provisions for designated participants are recommended by the Chairman, President and CEO of MGP, subject to review and approval of the Compensation Committee. Vesting of all grants outstanding is subject to the satisfaction of certain financial tests, which management currently believes is probable. Grants issued to LTIP participants are expected to cliff vest on January 1st of the third year following issuance of the grants. We account for forfeitures of non-vested LTIP grants as they occur. We expect to settle the non-vested LTIP grants by delivery of ARLP common units, except for the portion of the grants that will satisfy employee tax withholding obligations of LTIP participants. As provided under the distribution equivalent rights ("DERs") provisions of the LTIP and the terms of the LTIP awards, all non-vested grants include contingent rights to receive quarterly distributions in cash or, at the discretion of the Compensation Committee, phantom units in lieu of cash credited to a bookkeeping account with value equal to the cash distributions we make to unitholders during the vesting period.

A summary of non-vested LTIP grants is as follows:

	Number of units	Weighted average grant date fair value per unit	Intrinsic value (in thousands)
Non-vested grants at January 1, 2017	1,604,748	$ 23.19	$ 36,027
Granted	475,310	23.17	
Vested (1)	(350,516)	40.73	
Forfeited	(35,516)	20.01	
Non-vested grants at December 31, 2017	1,694,026	19.62	33,372
Granted	511,305	20.40	
Vested (1)	(331,502)	34.61	
Forfeited	(45,749)	17.40	
Non-vested grants at December 31, 2018	1,828,080	17.18	31,699
Granted	682,155	18.63	
Vested (1)	(885,381)	12.38	
Forfeited	(21,476)	20.84	
Non-vested grants at December 31, 2019	1,603,378	20.39	17,349

(1) During the years ended December 31, 2019, 2018 and 2017, we issued 596,650, 191,858 and 222,011, respectively, unrestricted common units to the LTIP participants. The remaining vested units were settled in cash primarily to satisfy tax withholding obligations of the LTIP participants.

For the years ended December 31, 2019, 2018 and 2017, our LTIP expense was $10.4 million, $10.8 million and $11.0 million, respectively. The total obligation associated with the LTIP as of December 31, 2019 and 2018 was $20.2 million and $20.8 million, respectively, and is included in the partners' capital *Limited partners-common unitholders* line item in our consolidated balance sheets. As of December 31, 2019, there was $12.5 million in total unrecognized compensation expense related to the non-vested LTIP grants that are expected to vest. That expense is expected to be recognized over a weighted-average period of 1.2 years.

On January 22, 2020, the Compensation Committee determined that the vesting requirements for the 2017 grants of 424,486 restricted units (which was net of 50,824 forfeitures and previously settled units) had been satisfied as of January 1, 2020. As a result of this vesting, on February 10, 2020, we issued 279,622 unrestricted common units to the LTIP participants. The remaining units were settled in cash to satisfy tax withholding obligations of the LTIP participants. On January 22, 2020, the Compensation Committee also authorized additional grants of 965,035 restricted units, of which 950,035 units were granted.

After consideration of the January 1, 2020 vesting and subsequent issuance of 279,622 common units, approximately 1.0 million units remain available under the LTIP for issuance in the future, assuming all grants issued in 2020, 2019 and 2018 and currently outstanding are settled with common units, without reduction for tax withholding, no future forfeitures occur and DERs continue being paid in cash versus additional phantom units.

Supplemental Executive Retirement Plan and Directors' Deferred Compensation Plan

We utilize the SERP to provide deferred compensation benefits for certain officers and key employees. All allocations made to participants under the SERP are made in the form of "phantom" ARLP units and SERP distributions will be settled in the form of ARLP common units. The SERP is administered by the Compensation Committee.

Our directors participate in the Directors' Deferred Compensation Plan. Pursuant to the Directors' Deferred Compensation Plan, for amounts deferred either automatically or at the election of the director, a notional account is established and credited with notional common units of ARLP, described in the Directors' Deferred Compensation Plan as "phantom" units. Distributions from the Directors' Deferred Compensation Plan will be settled in the form of ARLP common units.

For both the SERP and Directors' Deferred Compensation Plan, when quarterly cash distributions are made with respect to ARLP common units, an amount equal to such quarterly distribution is credited to each participant's notional account as additional phantom units. All grants of phantom units under the SERP and Directors' Deferred Compensation Plan vest immediately.

A summary of SERP and Directors' Deferred Compensation Plan activity is as follows:

	Number of units	Weighted average grant date fair value per unit	Intrinsic value (in thousands)
Phantom units outstanding as of January 1, 2017	494,018	$ 29.77	$ 11,091
Granted	67,766	20.38	
Phantom units outstanding as of December 31, 2017	561,784	28.64	11,067
Granted	84,417	18.78	
Issued (1)	(10,364)	27.92	
Phantom units outstanding as of December 31, 2018	635,837	27.34	11,025
Granted	111,012	14.50	
Issued (1)	(115,484)	25.20	
Phantom units outstanding as of December 31, 2019	631,365	25.48	6,831

(1) During the years ended December 31, 2019 and 2018, we issued ARLP common units of 115,484 and 7,181, respectively, to participants under the SERP and Directors' Deferred Compensation Plan. Units issued in 2018 were net of units settled in cash to satisfy tax withholding obligations.

Total SERP and Directors' Deferred Compensation Plan expense was $1.6 million, $1.6 million and $1.4 million for the years ended December 31, 2019, 2018 and 2017, respectively. As of December 31, 2019 and 2018, the total obligation associated with the SERP and Directors' Deferred Compensation Plan was $16.1 million and $17.4 million, respectively, and is included in the partners' capital *Limited partners-common unitholders* line item in our consolidated balance sheets.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for unit-based compensation.

17. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Cash Paid For:			
Interest	$ 43,093	$ 38,450	$ 31,692
Income taxes	$ —	$ 34	$ 210
Non-Cash Activity:			
Accounts payable for purchase of property, plant and equipment	$ 14,504	$ 14,585	$ 15,636
Assets acquired by finance lease	$ —	$ 835	$ —
Right-of-use assets acquired by operating lease	$ 25,593	—	—
Market value of common units issued under deferred compensation plans before tax withholding requirements	$ 17,415	$ 6,142	$ 8,149
Acquisition of businesses:			
Fair value of assets assumed	$ 629,475	$ —	$ —
Previously held equity-method investments (1)	(307,322)	—	—
Cash paid, net of cash acquired	(320,232)	—	—
Fair value of liabilities assumed	$ 1,921	$ —	$ —

(1) Inclusive of gain of $177.0 million as discussed in Note 3 – Acquisitions.

18. ASSET RETIREMENT OBLIGATIONS

The majority of our operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations require, among other things, restoration of property in accordance with specified standards and an approved reclamation plan.

The following table presents the activity affecting the asset retirement and mine closing liability:

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Beginning balance	$ 137,114	$ 130,600
Accretion expense	4,087	3,926
Payments	(2,948)	(2,392)
Allocation of liability associated with acquisitions, mine development and change in assumptions	(739)	4,980
Ending balance	$ 137,514	$ 137,114

For the year ended December 31, 2019, the allocation of liability associated with acquisition, mine development and change in assumptions was immaterial.

For the year ended December 31, 2018, the allocation of liability associated with acquisition, mine development and change in assumptions was a net increase of $5.0 million. This net increase was attributable to the expansion of refuse sites primarily at the Hamilton County Coal, LLC ("Hamilton") and Tunnel Ridge, LLC ("Tunnel Ridge") mines, partially offset by decreased cost estimates for water related treatment at the Mettiki mine and completion of certain reclamation obligations at the Hopkins County Coal mining complex.

The impact of discounting our estimated cash flows resulted in reducing the accrual for asset retirement obligations by $102.9 million and $100.3 million at December 31, 2019 and 2018, respectively. Estimated payments of asset retirement obligations as of December 31, 2019 are as follows:

Year Ended December 31,	(in thousands)
2020	$ 4,496
2021	2,576
2022	2,794
2023	2,027
2024	2,986
Thereafter	225,584
Aggregate undiscounted asset retirement obligations	240,463
Effect of discounting	(102,949)
Total asset retirement obligations	137,514
Less: current portion	(4,496)
Asset retirement obligations	$ 133,018

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and are typically renewable on a yearly basis. As of December 31, 2019 and 2018, we had approximately $181.6 million and $169.3 million, respectively, in surety bonds outstanding to secure the performance of our reclamation obligations.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for asset retirement obligations.

19. ACCRUED WORKERS' COMPENSATION AND PNEUMOCONIOSIS BENEFITS

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Certain of our mine operating entities are liable under state statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay benefits for black lung disease (or pneumoconiosis) to eligible employees and former employees and their dependents. Both pneumoconiosis and traumatic claims are covered through our self-insured programs.

The following is a reconciliation of the changes in workers' compensation liability (including current and long-term liability balances):

	December 31,	
	2019	**2018**
	(in thousands)	
Beginning balance	$ 49,539	$ 54,439
Accruals increase	7,162	7,654
Payments	(11,320)	(10,837)
Interest accretion	1,606	1,454
Valuation loss (gain)	6,397	(3,171)
Ending balance	$ 53,384	$ 49,539

The discount rate used to calculate the estimated present value of future obligations for workers' compensation was 2.81% and 3.89% at December 31, 2019 and 2018, respectively.

The 2019 valuation loss was primarily attributable to a decrease in the discount rate used to calculate the estimated present value of future obligations as well as unfavorable changes in claims development. The 2018 valuation gain was primarily attributable to an increase in the discount rate used to calculate the estimated present value of future obligations as well as favorable changes in claims development.

As of December 31, 2019 and 2018, we had $90.2 million and $90.5 million, respectively, in surety bonds and letters of credit outstanding to secure workers' compensation obligations.

We limit our exposure to traumatic injury claims by purchasing a high deductible insurance policy that starts paying benefits after deductibles for the particular claim year have been met. Our workers' compensation liability above is presented on a gross basis and does not include our expected receivables on our insurance policy. Our receivables for traumatic injury claims under this policy as of December 31, 2019 and 2018 are $7.7 million and $8.1 million, respectively. Our receivables are included in *Other long-term assets* on our consolidated balance sheets.

The following is a reconciliation of the changes in pneumoconiosis benefit obligations:

	December 31,	
	2019	**2018**
	(in thousands)	
Benefit obligations at beginning of year	$ 72,095	$ 74,859
Service cost	2,593	2,525
Interest cost	3,044	2,542
Actuarial (gain) loss	23,298	(4,599)
Benefits and expenses paid	(3,347)	(3,232)
Benefit obligations at end of year	$ 97,683	$ 72,095

The following is a reconciliation of the changes in the pneumoconiosis benefit obligation recognized in accumulated other comprehensive loss:

	Year Ended December 31,		
	2019	**2018**	**2017**
	(in thousands)		
Net actuarial gain (loss)	$ (23,298)	$ 4,599	$ (7,938)
Reversal of amortization item:			
Net actuarial (gain) loss	(4,582)	2	(2,092)
Total recognized in accumulated other comprehensive loss	$ (27,880)	$ 4,601	$ (10,030)

The discount rate used to calculate the estimated present value of future obligations for pneumoconiosis benefits was 3.12%, 4.13% and 3.49% at December 31, 2019, 2018 and 2017, respectively.

	Year Ended December 31,		
	2019	**2018**	**2017**
	(in thousands)		
Amount recognized in accumulated other comprehensive loss consists of:			
Net actuarial loss	$ 31,927	$ 4,047	$ 8,648

The actuarial loss component of the change in benefit obligations in 2019 was primarily attributable to a) a decrease in the discount rate used to calculate the estimated present value of the future obligations and b) an increase in Federal and State benefit levels. These components were offset in part by favorable demographic changes in the at-risk population. The actuarial gain component of the change in benefit obligations in 2018 was primarily attributable to a) an increase in the discount rate used to calculate the estimated present value of the future obligations, b) a decrease in the assumed future medical benefit and expense levels and c) demographic changes in the at-risk population.

Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for pneumoconiosis and workers' compensation benefits:

	December 31, 2019	December 31, 2018
	(in thousands)	
Workers' compensation claims	$ 53,384	$ 49,539
Pneumoconiosis benefit claims	97,683	72,095
Total obligations	151,067	121,634
Less current portion	(11,175)	(11,137)
Non-current obligations	$ 139,892	$ 110,497

Both the pneumoconiosis benefit and workers' compensation obligations were unfunded at December 31, 2019 and 2018.

The pneumoconiosis benefit and workers' compensation expense consists of the following components:

	Year Ended December 31, 2019	2018	2017
		(in thousands)	
Black lung benefits:			
Service cost	$ 2,593	$ 2,525	$ 2,255
Interest cost (1)	3,044	2,542	2,555
Net amortization (1)	(4,582)	2	(2,092)
Total pneumoconiosis expense	1,055	5,069	2,718
Workers' compensation expense	17,541	11,270	12,215
Net periodic benefit cost	$ 18,596	$ 16,339	$ 14,933

(1) Interest cost and net amortization is included in the *Other income (expense)* line item within our consolidated statements of income (see Note 2 – Summary of Significant Accounting Policies).

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for workers' compensation and pneumoconiosis benefits.

20. RELATED-PARTY TRANSACTIONS

We have continuing related-party transactions with MGP and its affiliates. The Board of Directors and its Conflicts Committee review our related-party transactions that involve a potential conflict of interest between our general partner or its affiliates and ARLP or its subsidiaries or any other partner of ARLP to determine that such transactions are fair and reasonable to ARLP. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to ARLP.

Affiliate Coal Lease Agreements

The following table summarizes advanced royalties outstanding and related payments and recoupments under our affiliate coal lease agreements:

	SGP/Craft Foundations	WKY CoalPlay				
		Towhead Coal	Webster Coal	Henderson Coal	WKY CoalPlay	
	Tunnel Ridge	Henderson & Union Counties, KY	Webster County, KY	Henderson County, KY	Henderson & Union Counties, KY	Total
	Acquired 2005	Acquired December 2014	Acquired December 2014	Acquired December 2014	Acquired February 2015	
		(in thousands)				
As of January 1, 2017	—	7,195	3,319	5,044	4,262	19,820
Payments	6,000	3,598	2,568	2,522	2,131	16,819
Recoupment	(3,000)	(109)	(531)	—	(6)	(3,646)
As of December 31, 2017	3,000	10,684	5,356	7,566	6,387	32,993
Payments	—	3,597	2,570	2,520	2,131	10,818
Recoupment	(3,000)	(204)	(31)	—	(36)	(3,271)
Unrecoupable	—	—	(7,895)	—	—	(7,895)
As of December 31, 2018	—	14,077	—	10,086	8,482	32,645
Payments	4,500	3,597	2,568	2,521	2,131	15,317
Recoupment	(3,000)	(1,071)	—	—	(107)	(4,178)
Unrecoupable	—	—	(2,568)	—	—	(2,568)
As of December 31, 2019	1,500	16,603	—	12,607	10,506	41,216

SGP/Craft Foundations—In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease with SGP. Under the terms of the lease, Tunnel Ridge is required to pay an annual minimum royalty of $3.0 million. The lease expires the earlier of January 1, 2033 or upon the exhaustion of the mineable and merchantable leased coal. Tunnel Ridge incurred $7.2 million, $6.0 million and $7.2 million in earned royalties in 2019, 2018 and 2017 respectively. As of January 1, 2019 the property subject to this lease is owned by the Joseph W. Craft III Foundation and the Kathleen S. Craft Foundation, an undivided one-half interest each (the "Craft Foundations").

WKY CoalPlay—In February 2015, WKY CoalPlay entered into a coal lease agreement with Alliance Resource Properties, LLC ("Alliance Resource Properties") regarding coal reserves located in Henderson and Union Counties, Kentucky. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $2.1 million. All annual minimum royalty payments are recoupable from future earned royalties. Alliance Resource Properties also was granted an option to acquire the leased reserves at any time during a three-year period beginning in February 2018 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the lease (See Note 11 – Variable Interest Entities).

In December 2014, WKY CoalPlay's subsidiaries, Towhead Coal Reserves, LLC and Henderson Coal Reserves, LLC entered into coal lease agreements with Alliance Resource Properties. The leases have initial terms of 20 years and provide for earned royalty payments of 4.0% of the coal sales price to both and annual minimum royalty payments of $3.6 million and $2.5 million, respectively. All annual minimum royalty payments for each agreement are recoupable from future earned royalties related to their respective agreements. Each agreement grants Alliance Resource Properties an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in the reserves taking into account payments previously made under the leases (See Note 11 – Variable Interest Entities).

In December 2014, WKY CoalPlay's subsidiary, Webster Coal Reserves, LLC entered into a coal lease agreement with Alliance Resource Properties. The lease has an initial term of 7 years and provides for earned royalty payments of 4.0% of the coal sales price and annual minimum payments of $2.6 million. The agreement grants Alliance Resource Properties an option to acquire the leased reserves at any time during a three year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in the reserves taking into account payments previously made under the lease (See Note 11 – Variable Interest Entities). In the third quarter of 2019 it was determined that the balance of advanced royalties and the remaining future advance royalties payable in 2020 and 2021 totaling $5.1 million, may not be recouped as a result of the reduction of the Dotiki's economic mine life determined in 2018 and the subsequent ceasing of production in the third quarter of 2019. We accrued the future advance payments and recognized the charge in Asset Impairment expense in the third quarter of 2019. See Note 4 – Long-Lived Asset Impairments for more information.

Cavalier Minerals– As discussed in Note 11 – Variable Interest Entities, through our subsidiaries, we hold a non-economic managing member interest and a 96% non-managing member interest in Cavalier and, Bluegrass Minerals, a third party, holds a 4% non-managing member interest and profits interest. See Note 12 – Investments for information on payments made and distributions received by Cavalier.

21. COMMITMENTS AND CONTINGENCIES

***Commitments*—**We lease buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. We also have noncancelable coal reserve leases as discussed in Note 20 – Related-Party Transactions and noncancelable leases with a third party for equipment under finance lease obligations. For information regarding future minimum lease payments see Note 8 – Leases.

***Contractual Commitments*—**In connection with planned capital projects, we have contractual commitments of approximately $28.6 million at December 31, 2019. As of December 31, 2019, we had no commitments to purchase coal from external production sources in 2020.

***General Litigation*—**On March 9, 2018, we finalized an agreement with a customer and certain of its affiliates to settle breach of contract litigation we initiated in January 2015. The agreement provided for a $93.0 million cash payment to us, execution of a new coal supply agreement with the customer, continued export transloading capacity for our Appalachian mines and the acquisition of certain coal reserves for $2.0 million from an affiliate of the customer. The $93.0 million cash payment we received in March was the total compensation recorded in our consolidated statements of income for the agreement. We have paid or accrued in total, $13.0 million of legal fees and associated incentive compensation costs related to this settlement which resulted in a net gain of $80.0 million reflected in the Settlement gain line item in our consolidated statements of income.

Various lawsuits, claims and regulatory proceedings incidental to our business are pending against the ARLP Partnership. We record an accrual for a potential loss related to these matters when, in management's opinion, such loss is probable and reasonably estimable. Based on known facts and circumstances, we believe the ultimate outcome of these outstanding lawsuits, claims and regulatory proceedings will not have a material adverse effect on our financial condition, results of operations or liquidity. However, if the results of these matters were different from management's current opinion and in amounts greater than our accruals, then they could have a material adverse effect.

***Other*—**Effective October 1, 2019, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance, LLC ("Wildcat Insurance"). Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market. The maximum limit in the commercial property program is $100.0 million per occurrence, excluding a $1.5 million deductible for property damage, a 60, 75, 90 or 120 day waiting period for underground business interruption depending on the mining complex and an additional $10.0 million overall aggregate deductible. We have elected to retain a 10% participating interest in our commercial property insurance program. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future. Also, exposures exist for which no insurance may be available and for which we have not set aside cash reserves. In addition, environmental activists may try to hamper fossil fuel companies by other means including pressuring insurance and surety companies into restricting access to certain needed coverages.

22. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

The international coal market has been a substantial part of our business with indirect sales to end users in Europe, Africa, Asia, North America and South America. Our sales into the international coal market are considered exports and are made through brokered transactions. During the years ended December 31, 2019, 2018 and 2017, export tons represented approximately 17.9%, 27.8% and 17.4% of tons sold, respectively.

We use the end usage point as the basis for attributing tons to individual countries. Because title to our export shipments typically transfers to our brokerage customers at a point that does not necessarily reflect the end usage point, we attribute export tons to the country with the end usage point, if known. No individual country was attributed greater than 10% of total domestic and export tons sold during the years ended December 31, 2019, 2018 and 2017.

We have significant long-term coal supply agreements, some of which contain prospective price adjustment provisions designed to reflect changes in market conditions, labor and other production costs and, in the infrequent circumstance when the coal is sold other than free on board the mine, changes in transportation rates. Our major customers are defined as those customers from which we derive at least ten percent of our total revenues, including transportation revenues. Total revenues from major customers are as follows:

		Year Ended December 31,		
	Segment	**2019**	**2018**	**2017**
			(in thousands)	
Customer A	Illinois Basin	$ 228,500	$ 219,115	$ —
Customer B	Appalachia	213,319	—	—

Trade accounts receivable from these customers totaled approximately $26.3 million at December 31, 2019. Trade accounts receivable from Customer A totaled approximately $12.8 million at December 31, 2018. Our bad debt experience has historically been insignificant. Financial conditions of our customers could result in a material change to our bad debt expense in future periods. The coal supply agreements with these customers expire in 2020 for Customer A and 2022 for Customer B.

23. SEGMENT INFORMATION

We operate in the United States as a diversified natural resource company that generates income from the production and marketing of coal to major domestic and international utilities and industrial users as well as income from oil & gas mineral interests. We aggregate multiple operating segments into three reportable segments, Illinois Basin, Appalachia, and Minerals. We also have an "all other" category referred to as Other and Corporate. Our two coal reportable segments correspond to major coal producing regions in the eastern United States with similar economic characteristics including coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues. The two coal segments include seven mining complexes operating in Illinois, Indiana, Kentucky, Maryland and West Virginia and a coal loading terminal in Indiana on the Ohio River. The Minerals reportable segment aggregates our oil & gas mineral interests which are located primarily in the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) Basins. As discussed in Note 1 – Organization and Presentation, as a result of the AllDale Acquisition discussed in Note 3 – Acquisitions, we realigned our reportable segments in 2019 to include our oil & gas mineral interests within a new Minerals reportable segment and have recast prior periods to reflect that realignment.

The Illinois Basin reportable segment includes our operating mining complexes (a) Gibson County Coal, LLC's mining complex, which includes the Gibson North and Gibson South mines, (b) Warrior Coal, LLC's mining complex, (c) River View's mining complex and (d) the Hamilton mining complex. The Illinois Basin reportable segment also includes our operating Mt. Vernon coal loading terminal in Indiana on the Ohio River. The Gibson North mine was idled in the fourth quarter of 2019 in response to market conditions.

The Illinois Basin reportable segment also includes MAC and other support services as well as non-operating mining complexes (a) Webster County Coal, LLC's Dotiki mining complex, which ceased production in August 2019, (b) White County Coal, LLC's Pattiki mining complex, (c) the Hopkins County Coal mining complex, and (d) Sebree Mining, LLC's mining complex.

The Appalachia reportable segment includes our operating mining complexes (a) the Mettiki mining complex, (b) the Tunnel Ridge mining complex and (c) the MC Mining mining complex. The Mettiki mining complex includes Mettiki Coal (WV), LLC's Mountain View mine and Mettiki Coal, LLC's preparation plant. The Appalachia reportable segment also includes the Penn Ridge reserves.

The Minerals reportable segment includes oil & gas mineral interests held by AR Midland and AllDale I & II and includes Alliance Minerals' equity interests in both AllDale III (Note 12 – Investments) and Cavalier Minerals. AR Midland acquired its mineral interest in the Wing Acquisition (Note 3 – Acquisitions).

Other and Corporate includes marketing and administrative activities, Matrix Design Group, LLC and its subsidiaries ("Matrix Design"), Alliance Design Group, LLC ("Alliance Design") (collectively, Matrix Design and Alliance Design referred to as the "Matrix Group"), Alliance Coal's coal brokerage activity and Alliance Minerals' prior equity investment in Kodiak. In February 2019, Kodiak redeemed our equity investment (see Note 12 – Investments). In addition, Other and Corporate includes certain Alliance Resource Properties' land and mineral interest activities, Pontiki Coal, LLC's workers' compensation and pneumoconiosis liabilities, Wildcat Insurance, which assists the ARLP Partnership with its insurance requirements, and AROP Funding and Alliance Finance (both discussed in Note 7 – Long-Term Debt).

Reportable segment results are presented below.

	Illinois Basin	Appalachia	Minerals	Other and Corporate	Elimination (1)	Consolidated
			(in thousands)			
Year Ended December 31, 2019						
Revenues - Outside	$ 1,219,618	$ 644,389	$ 53,036	$ 44,677	$ —	$ 1,961,720
Revenues - Intercompany	16,690	—	—	12,173	(28,863)	—
Total revenues (2)	1,236,308	644,389	53,036	56,850	(28,863)	1,961,720
Segment Adjusted EBITDA Expense (3)	756,423	423,623	7,811	36,845	(19,806)	1,204,896
Segment Adjusted EBITDA (4)	385,200	215,950	46,997	32,911	(9,057)	672,001
Total assets	1,373,516	500,027	643,213	541,261	(471,323)	2,586,694
Capital expenditures (5)	189,270	111,739	—	4,849	—	305,858
Year Ended December 31, 2018						
Revenues - Outside	$ 1,289,898	$ 643,898	$ —	$ 69,061	$ —	$ 2,002,857
Revenues - Intercompany	31,191	67	—	12,431	(43,689)	—
Total revenues (2)	1,321,089	643,965	—	81,492	(43,689)	2,002,857
Segment Adjusted EBITDA Expense (3)	796,370	398,243	—	52,321	(35,134)	1,211,800
Segment Adjusted EBITDA (4)	417,773	240,286	21,323	44,864	(8,555)	715,691
Total assets	1,380,912	440,518	161,312	589,010	(177,004)	2,394,748
Capital expenditures	166,468	64,037	—	2,975	—	233,480
Year Ended December 31, 2017						
Revenues - Outside	$ 1,069,767	$ 623,720	$ —	$ 102,733	$ —	$ 1,796,220
Revenues - Intercompany	56,097	2,321	—	12,016	(70,434)	—
Total revenues (2)	1,125,864	626,041	—	114,749	(70,434)	1,796,220
Segment Adjusted EBITDA Expense (3)	692,199	385,802	—	75,851	(61,665)	1,092,187
Segment Adjusted EBITDA (4)	398,080	234,124	13,297	45,296	(8,769)	682,028
Total assets	1,437,627	470,892	147,970	349,918	(187,036)	2,219,371
Capital expenditures	94,374	48,358	—	2,356	—	145,088

(1) The elimination column represents the elimination of intercompany transactions and is primarily comprised of sales from the Matrix Group to our mining operations, coal sales and purchases between operations within different segments, sales of receivables to AROP Funding, financing between segments and insurance premiums paid to Wildcat Insurance.

(2) Revenues included in the Other and Corporate column are primarily attributable to the outside and affiliate revenues at the Matrix Group and coal brokerage activities. In additions, Other and Corporate includes affiliate revenues for administrative and Wildcat Insurance services.

(3) Segment Adjusted EBITDA Expense includes operating expenses, coal purchases and other income. Transportation expenses are excluded as transportation revenues are recognized in an amount equal to transportation expenses when title passes to the customer.

The following is a reconciliation of consolidated Segment Adjusted EBITDA Expense to *Operating expenses (excluding depreciation, depletion and amortization)*:

	Year Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Segment Adjusted EBITDA Expense	$ 1,204,896	$ 1,211,800	$ 1,092,187
Outside coal purchases	(23,357)	(1,466)	—
Other income (expense)	561	(2,621)	(332)
Operating expenses (excluding depreciation, depletion and amortization)	$ 1,182,100	$ 1,207,713	$ 1,091,855

(4) Segment Adjusted EBITDA is defined as net income attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization, general and administrative expense, settlement gain, debt extinguishment loss, asset impairment and acquisition gain. Management therefore is able to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments. Consolidated Segment Adjusted EBITDA is reconciled to net income as follows:

	Year Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Consolidated Segment Adjusted EBITDA	$ 672,001	$ 715,691	$ 682,028
General and administrative	(72,997)	(68,298)	(61,760)
Depreciation, depletion and amortization	(309,075)	(280,225)	(268,981)
Settlement gain	—	80,000	—
Asset impairment	(15,190)	(40,483)	—
Interest expense, net	(45,496)	(40,059)	(39,291)
Acquisition gain	177,043	—	—
Debt extinguishment loss	—	—	(8,148)
Income tax (expense) benefit	211	(22)	(210)
Acquisition gain attributable to noncontrolling interest	(7,083)	—	—
Net income attributable to ARLP	$ 399,414	$ 366,604	$ 303,638
Noncontrolling interest	7,512	866	563
Net income	$ 406,926	$ 367,470	$ 304,201

(5) Capital Expenditures shown exclude the AllDale Acquisition on January 3, 2019 and the Wing Acquisition on August 2, 2019 (Note 3 – Acquisitions).

24. SUBSEQUENT EVENTS

Other than those events described in Notes 10 and 16, there were no subsequent events.

SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our consolidated quarterly operating results is as follows:

	Quarter Ended			
	March 31, 2019 (1)	June 30, 2019	September 30, 2019 (2)	December 31, 2019
	(in thousands, except unit and per unit data)			
Revenues	$ 526,602	$ 517,054	$ 464,726	$ 453,338
Income from operations	104,685	68,406	50,426	35,981
Income before income taxes	283,498	58,370	39,251	25,596
Net income attributable to ARLP	276,428	58,070	39,084	25,832
Basic and diluted net income attributable to ARLP per limited partner unit	$ 2.12	$ 0.44	$ 0.30	$ 0.20
Weighted-average number of units outstanding – basic and diluted	128,149,791	128,391,191	128,391,191	127,538,211

	Quarter Ended			
	March 31, 2018 (3)	June 30, 2018	September 30, 2018	December 31, 2018 (4)
	(in thousands, except unit and per unit data)			
Revenues	$ 457,122	$ 516,137	$ 497,758	$ 531,840
Income from operations	160,226	88,160	74,625	49,276
Income before income taxes	156,046	86,380	73,974	51,092
Net income attributable to ARLP	155,908	86,190	73,733	50,773
Basic and diluted net income attributable to ARLP per limited partner unit	$ 1.16	$ 0.64	$ 0.55	$ 0.38
Weighted-average number of units outstanding – basic and diluted	130,819,217	131,279,910	131,169,538	129,771,010

(1) Our March 31, 2019 quarterly results were affected by a non-cash acquisition gain of $177.0 million reflecting the re-measurement of our equity method investments in AllDale I & II as a result of the AllDale Acquisition (Note 3 – Acquisitions).

(2) Our September 30, 2019 quarterly results were affected by $15.2 million of non-cash impairment charges due to the closure of our Dotiki mine during the quarter (Note 4 – Long-Lived Asset Impairments).

(3) Our March 31, 2018 quarterly results were affected by a settlement gain of $80.0 million reflecting cash payment received from the settlement of litigation, net of certain costs associated with the gain (Note 21 – Commitments and Contingencies).

(4) Our December 31, 2018 quarterly results were affected by $40.5 million of non-cash impairment charges comprised of a $34.3 million impairment related to the reduction of the economic mine life at our Dotiki mine and a $6.2 million impairment as a result of a decrease in the fair value of an option entitling us to lease certain coal reserves in Illinois (Note 4 – Long-Lived Asset Impairments).

SUPPLEMENTAL OIL & GAS RESERVE INFORMATION (UNAUDITED)

These supplemental oil & gas reserve information disclosures are required for periods in which a company has significant oil & gas producing activities. A company is considered to have significant oil & gas producing activities if any of its revenues, results of operations or assets from oil & gas producing activities exceed 10% of consolidated revenues, results of operations or assets for the year being measured. As a result of the AllDale and Wing Acquisitions discussed in Note 3 – Acquisitions in our consolidated financial statements, we are considered to have significant oil & gas producing activities as of December 31, 2019. We were not considered to have significant oil & gas producing activities in prior years when we held equity method investments in the AllDale Partnerships and therefore have not included these reserve disclosures for any prior periods.

Geographical Area of Operation

All of our proved oil & gas reserves are located within the continental United States with the majority concentrated in Texas, Oklahoma, New Mexico and North Dakota. The following supplemental disclosures about our proved oil & gas reserves including costs incurred, capitalized cost, results of operations and cash flows are presented on a consolidated basis.

Costs Incurred in Oil & Gas Property Acquisitions

Costs incurred in oil & gas property acquisitions are presented below:

	Year Ended December 31, 2019
	(in thousands)
Acquisition costs of properties	
Proved	242,116
Unproved	376,166
Total	618,282

Property acquisition costs include non-cash amounts for the AllDale Acquisition. In connection with the AllDale Acquisition, we marked our previously held equity method investments to a fair value of $307.3 million, resulting in a $177.0 million gain. See Note 3 – Acquisitions in our consolidated financial statements for more information.

Oil & Gas Capitalized Costs

Aggregate capitalized costs related to oil & gas activities with applicable accumulated depreciation, depletion, and amortization are presented below:

	As of December 31, 2019 (in thousands)	
	Consolidated	Our Share of an Equity Method Investee
Proved properties	$ 242,116	$ 8,217
Unproved properties	376,166	20,531
Total	618,282	28,748
Less accumulated depreciation, depletion and amortization	(22,658)	(1,194)
Oil & gas properties, net	$ 595,624	$ 27,554

Results of Operations from Oil & Gas Activities

The following schedule sets forth the revenues and expenses related to our oil & gas mineral interests. It does not include any interest costs or general and administrative costs, and therefore, is not necessarily indicative of the contribution to the results of our Minerals segment.

	Year Ended December 31, 2019
	(in thousands)
Consolidated activities	
Oil & gas royalties	$ 51,735
Other revenues	1,301
Production costs and severance taxes	(7,859)
Depreciation, depletion and amortization	(22,658)
Total results of oil & gas activities	$ 22,519
Our share of an equity method investee	
Oil & gas royalties	$ 3,200
Other revenues	190
Production costs and severance taxes	(411)
Depreciation, depletion and amortization	(854)
Total results of oil & gas activities	$ 2,125

Oil & Gas Reserves

Proved oil & gas reserve estimates as of December 31, 2019 were prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. Proved reserves are estimated under existing economic and operating conditions based upon the 12-month unweighted average of the first-of-the-month prices.

Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

The net proved developed and undeveloped oil & gas reserves quantities of the mineral interests attributable to us are summarized below:

	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
Consolidated activities				
As of January 1, 2019	—	—	—	—
Purchases of minerals in place	6,509	30,055	3,477	14,995
Revisions of previous estimates	1,015	1,956	(548)	793
Production	(700)	(3,382)	(347)	(1,611)
As of December 31, 2019 (1)	6,824	28,629	2,582	14,177

(1) As of December 31, 2019, proved reserves of approximately 1,208 MBOE was attributable to noncontrolling interests.

Our share of an equity method investee	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
As of January 1, 2019	295	2,205	—	662
Revisions of previous estimates	78	11	153	234
Sales of mineral interests in place	(7)	(8)	—	(8)
Production	(41)	(282)	(17)	(105)
As of December 31, 2019	325	1,926	136	783
Net proved developed reserves as of December 31, 2019	5,766	24,449	2,009	11,850
Net proved undeveloped reserves as of December 31, 2019	1,383	6,106	709	3,110

Natural gas reserves are converted to BOE based on a 6:1 ratio: six Mcf of natural gas converts to one BOE.

Notable changes in proved reserves during the year ended December 31, 2019, included:

- *Purchases of minerals in place:* The increases represent the acquisition of mineral interests in the AllDale and Wing Acquisitions. Please see Note 3 – Acquisitions in our consolidated financial statements for more information.

- *Revisions:* Increases in oil & gas are also due to changes in the underlying commodity prices during the year and revisions of previous quantity estimates.

Standardized Measure of Discounted Future Net Cash Flows

In accordance with SEC and FASB requirements, future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the 12-month unweighted average of first-of-the-month commodity prices for the year ended December 31, 2019. All prices are adjusted for quality, transportation fees, energy content and regional basis differentials. Future cash inflows are computed by applying applicable prices relating to our proved reserves to the year end quantities of those reserves. Future production costs are derived based on current costs assuming continuation of existing economic conditions. There are no future income tax expenses deducted from future production revenues in the calculation of the standardized measure because the ARLP Partnership is generally not subject to federal income taxes. The ARLP Partnership is subject to certain state based taxes; however, these amounts are not material. See Note 2 – Summary of Significant Accounting Policies for further discussion.

While due care was taken in preparation of the following cash flow projections, we do not represent that this data is the fair value of our oil & gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices are expected to vary significantly from those used and actual costs may vary.

	As of December 31, 2019 (in thousands)	
	Consolidated	Our Share of an Equity Method Investee
Future cash inflows	$ 463,972	$ 24,372
Future production costs and severance taxes	(34,997)	(1,515)
Future net cash flows (undiscounted)	428,975	22,857
Annual discount 10% for estimated timing	(198,025)	(10,642)
Total standardized measure (1)	$ 230,950	$ 12,215

(1) Includes standardized discounted future net cash flows of approximately $12.5 million attributable to noncontrolling interests in the ARLP Partnership's consolidated subsidiaries.

The average realized product prices weighted by production over the remaining lives of the properties are $52.32 per barrel of oil, $1.83 per thousand cubic feet of natural gas and $21.95 per barrel of NGL.

Changes in the standardized measure of discounted future net cash flows related to the proved oil & gas reserves of the properties are as follows:

	As of December 31, 2019 (in thousands)	
	Consolidated	Our Share of an Equity Method Investee
Standardized measure, beginning of year	—	12,845
Purchases of reserves in place, less related costs	231,287	(252)
Sales, net of production costs	(43,875)	(2,788)
Net changes in prices and production costs	10,533	(2,517)
Revisions of previous quantity estimates, net of related costs	14,560	3,398
Accretion of discount	18,403	1,284
Changes in timing and other	42	245
Standardized measure, end of year	230,950	12,215

The standardized measure amount at the beginning of the year for the Our share of an Equity Method Investee reflects only our proportionate share of AllDale III's beginning of the year standardized measure amount. Our previously held equity method investments in AllDale I & II, as a result of the AllDale Acquisition at the beginning of year, are now consolidated on our financial statements. Accordingly, we reflect the activity for AllDale I & II in our consolidated standardized measure amounts and not the Equity Method amounts.

SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2019, 2018 AND 2017

	Balance At Beginning of Year	Additions Charged to Income	Deductions	Balance At End of Year
	(in thousands)			
2019				
Allowance for doubtful accounts	$ —	$ —	$ —	$ —
2018				
Allowance for doubtful accounts	$ —	$ —	$ —	$ —
2017				
Allowance for doubtful accounts	$ —	$ —	$ —	$ —

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. We maintain controls and procedures designed to provide reasonable assurance that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Exchange Act) as of December 31, 2019. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures are effective as of December 31, 2019.

Our management, including the Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the ARLP Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based, in part, upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

Management's Annual Report on Internal Control over Financial Reporting. Management of the ARLP Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Exchange Act. The ARLP Partnership's internal control over financial reporting is designed to provide reasonable assurance to our management and Board of Directors of our general partner regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the ARLP Partnership's assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are complemented by a staff of competent business process owners and an internal auditor supported by competent and qualified external resources used to assist in testing the operating effectiveness of the ARLP Partnership's internal control over financial reporting. Management concluded that the design and operations of our internal controls over financial reporting at December 31, 2019 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the ARLP Partnership.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework (2013)*. Based on its assessment, management concluded that, as of December 31, 2019, the ARLP Partnership's internal control over financial reporting was effective based on those criteria, and management believes that we have no material internal control weaknesses in our financial reporting process.

Ernst & Young LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2019, as stated in their report that is included herein.

As permitted by SEC rules, we have excluded the mineral interest operations we acquired on January 3, 2019 in the AllDale Acquisition and August 2, 2019 in the Wing Acquisition as discussed below from our evaluations of the effectiveness of internal control over financial reporting for the year ended December 31, 2019 due to the size, complexity and the limited time available to complete the evaluations. The operations excluded from our evaluations represent approximately 23.7% of our total assets at December 31, 2019 and approximately 2.7% of our total revenues for the year ended December 31, 2019.

Changes in Internal Controls Over Financial Reporting. Other than the changes that have resulted or may result from the AllDale Acquisition and Wing Acquisition as discussed below, there have not been any changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) or Rule 15d-15(f) of the Exchange Act) in the three months ended December 31, 2019 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

On January 3, 2019 (the "AllDale Acquisition Date"), we acquired all of the limited partner interests in AllDale Minerals, LP and AllDale Minerals II, LP (collectively, "AllDale I & II") not owned by Cavalier Minerals JV, LLC ("Cavalier Minerals") and the general partner interests in AllDale I & II (the "AllDale Acquisition"). As of the AllDale Acquisition Date, we now own 100% of the general partner interests and, including the limited partner interests we hold indirectly through our ownership in Cavalier Minerals, approximately 97% of the limited partner interests in AllDale I & II. In addition, we assumed control and began accounting for AllDale I & II on a consolidated basis. On August 2, 2019, we acquired approximately 9,000 net royalty acres in the Midland Basin, (the "Wing Acquisition"). For more information on the AllDale and Wing Acquisitions, please see "Item 8. Financial Statements and Supplementary Data — Note 3. Acquisitions."

At this time, we continue to evaluate the business and internal controls and processes around the mineral interests acquired in both the AllDale and Wing Acquisitions and are making various changes to their management and organizational structures based on our business plan. We are in the process of implementing our internal control structure over the acquired businesses. We expect to complete the evaluation and integration of the internal controls and processes of the mineral interests acquired in the AllDale and Wing Acquisitions in the first and third quarters of 2020, respectively.

Report of Independent Registered Public Accounting Firm

The Board of Directors of Alliance Resource Management GP, LLC
and the Partners of Alliance Resource Partners, L.P.

Opinion on Internal Controls over Financial Reporting

We have audited Alliance Resource Partners, L.P. and subsidiaries' internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Alliance Resource Partners, L.P. and subsidiaries (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria**.**

As indicated in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*, management's assessment of, and conclusion on, the effectiveness of internal controls over financial reporting did not include the internal controls and processes of the mineral interests acquired in both the Wing and AllDale Acquisitions, which are included in the 2019 financial statements of the Partnership and constituted 23.9% and 48.9% of total and net assets, respectively, as of December 31, 2019 and 2.7% and 4.9% of revenues and net income, respectively, for the year then ended. Our audit of internal control over financial reporting of the Partnership also did not include an evaluation of the internal control over financial reporting of the mineral interests acquired in both the Wing and AllDale Acquisitions.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, cash flows, and partners' capital for each of the three years in the period ended December 31, 2019, the related notes and financial statement schedule, and our report dated February 20, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 20, 2020

ITEM 9B. OTHER INFORMATION

None.

PART III

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

As is commonly the case with publicly traded limited partnerships, we are managed and operated by our general partner. The following table shows information for executive officers and members of the Board of Directors as of the date of the filing of this Annual Report on Form 10-K. Executive officers and directors are elected until death, resignation, retirement, disqualification, or removal.

Name	Age	Position With Our General Partner
Joseph W. Craft III	69	Chairman, President and Chief Executive Officer
Brian L. Cantrell	60	Senior Vice President and Chief Financial Officer
R. Eberley Davis	62	Senior Vice President, General Counsel and Secretary
Robert J. Fouch	62	Vice President, Controller and Chief Accounting Officer
Robert G. Sachse	71	Executive Vice President
Kirk D. Tholen	47	Senior Vice President and Chief Strategic Officer
Charles R. Wesley	65	Executive Vice President and Director
Timothy J. Whelan	57	Senior Vice President - Sales and Marketing of Alliance Coal, LLC
Thomas M. Wynne	63	Senior Vice President and Chief Operating Officer
Nick Carter	73	Director and Member of Audit, Compensation and Conflicts Committees
Robert J. Druten	72	Director and Member of Audit, Compensation and Conflicts* Committees
John H. Robinson	69	Director and Member of Audit, Compensation* and Conflicts Committees
Wilson M. Torrence	78	Director and Member of Audit* and Compensation Committees

* Indicates Chairman of Committee.

Joseph W. Craft III has been President, CEO and a Director since August 1999, Chairman of the Board of Directors since January 1, 2019, and indirectly owns our general partner. Previously Mr. Craft served as President of MAPCO Coal Inc. since 1986. During that period, he also was Senior Vice President of MAPCO Inc. and had previously been that company's General Counsel and Chief Financial Officer. He is a former Chairman and current Board member of the National Coal Council, a Board Member of the National Mining Association, and a Director and Chairman of America's Power. Mr. Craft is a past Director and Chairman of the Kentucky Chamber of Commerce and a Director and Executive Committee member of the United States Chamber of Commerce. He has been a Director of BOK Financial Corporation (NASDAQ: BOKF) since 2007 and chairman of its compensation committee since 2014. Mr. Craft holds a Bachelor of Science degree in Accounting and a Juris Doctorate degree from the University of Kentucky. Mr. Craft also is a graduate of the Senior Executive Program of the Alfred P. Sloan School of Management at Massachusetts Institute of Technology. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Craft should serve as a Director include his long history of significant involvement in the coal industry, his demonstrated business acumen and his exceptional leadership of the Partnership since its inception.

Brian L. Cantrell has been Senior Vice President and Chief Financial Officer since October 2003. Prior to his current position, Mr. Cantrell was President of AFN Communications, LLC from November 2001 to October 2003 where he had previously served as Executive Vice President and Chief Financial Officer after joining AFN in September 2000. Mr. Cantrell's previous positions include Chief Financial Officer, Treasurer and Director with Brighton Energy, LLC from August 1997 to September 2000; Vice President—Finance of KCS Medallion Resources, Inc.; and Vice President—

Finance, Secretary and Treasurer of Intercoast Oil and Gas Company. Mr. Cantrell is a Certified Public Accountant and holds Master of Accountancy and Bachelor of Accountancy degrees from the University of Oklahoma.

R. Eberley Davis has been Senior Vice President, General Counsel and Secretary since February 2007. From 2003 to February 2007, Mr. Davis practiced law in the Lexington, Kentucky office of Stoll Keenon Ogden PLLC. Prior to joining Stoll Keenon Ogden, Mr. Davis was Vice President, General Counsel and Secretary of Massey Energy Company for one year. Mr. Davis also served in various positions, including Vice President and General Counsel, for Lodestar Energy, Inc. from 1993 to 2002. Mr. Davis is an alumnus of the University of Kentucky, where he received a Bachelor of Arts degree in Economics and his Juris Doctorate degree. He also holds a Master of Business Administration degree from the University of Kentucky. Mr. Davis is a Trustee of the Energy and Mineral Law Foundation, and a member of the Kentucky Bar Association.

Robert J. Fouch became Chief Accounting Officer in February 2019. Since August 2006, Mr. Fouch has served as Vice President and Controller. Prior to his current position, from 1999 to 2006, Mr. Fouch served as Assistant Controller. Mr. Fouch joined Alliance's predecessor, MAPCO Inc. in 1981 and held a variety of accounting positions of increasing responsibility. He worked for the audit firm of Deloitte, Haskins and Sells prior to joining MAPCO. He is a Certified Public Accountant and holds a Bachelor of Science degree in Accounting from Oral Roberts University.

Robert G. Sachse has been Executive Vice President since August 2000. From November 2006 until the beginning of 2016, Mr. Sachse had responsibility for our coal marketing, sales and transportation functions. Mr. Sachse was also Vice Chairman of our general partner from August 2000 to January 2007. Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO merged with The Williams Companies. Mr. Sachse held various positions while with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree in Business Administration from Trinity University and a Juris Doctorate degree from the University of Tulsa.

Kirk D. Tholen became Senior Vice President and Chief Strategic Officer in December 2019 and also serves as President of ARLP's oil & gas minerals business. Prior to his current position, Mr. Tholen most recently served as a Managing Director within the Oil & Gas Group and Head of the Acquisitions and Divestitures ("A&D") Practice for Houlihan Lokey in Houston. From 2012 to 2015, he was Head of A&D for Credit Agricole CIB and was responsible for creating and leading their A&D platform to service domestic and cross-border client transactions as well as assisting in reserve-base lending, equity offerings and high yield debt offerings. From 2006 to 2012, Mr. Tholen provided business development, marketing, transaction management, negotiating and closing services to clients at Albrecht & Associates, Inc., a sell-side E&P boutique advisory firm. His previous industry experience also includes serving as a Region Engineer for BJ Services from 1996 to 2006, where he provided drilling and fracturing technical services to clients operating in the lower 48 and Gulf of Mexico predominately as a dedicated in-house engineer focused on drilling and completions for BP, Conoco and Devon. Mr. Tholen began his career in 1992 joining UNOCAL's Louisiana inland waters and shallow shelf operation and reservoir engineering team. He holds a Bachelor of Science degree in Chemical Engineering from the University of Louisiana at Lafayette and a Master of Business Administration degree from the University of Houston.

Charles R. Wesley has been a Director since January 2009 and Executive Vice President since March 2009. Mr. Wesley has served in a variety of capacities since joining the company in 1974, including as Senior Vice President—Operations from August 1996 through February 2009. Mr. Wesley is a former Chairman of the Board of Directors of the Kentucky Coal Association and also has served the industry as past President of the West Kentucky Mining Institute and National Mine Rescue Association Post 11, and as a director of the Kentucky Mining Institute. Mr. Wesley holds a Bachelor of Science degree in Mining Engineering from the University of Kentucky. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Wesley should serve as a Director include his long history of significant involvement in the coal industry, his successful leadership of the Partnership's operations, and his knowledge and technical expertise in all aspects of producing and marketing coal.

Timothy J. Whelan has been Senior Vice President - Sales and Marketing of Alliance Coal, LLC since May 2013. Since joining Alliance in September 2003, Mr. Whelan has held several positions with increasing responsibility, serving as Vice President – Sales prior to his current position. Mr. Whelan previously served in various business development positions for MAPCO Inc. and as Director, Power & Gas Origination for Williams Energy Marketing and Trading. Mr. Whelan has over 30 years of energy industry experience, and is a former board member of the American Coal Council and The Coal Institute. Mr. Whelan holds a Bachelor of Science degree in Finance from the University of Arkansas.

Thomas M. Wynne has been Senior Vice President and Chief Operating Officer since March 2009. Mr. Wynne joined the company in 1981 as a mining engineer and has held a variety of positions with the company prior to his appointment in July 1998 as Vice President—Operations. Mr. Wynne has served the coal industry on the National Executive Committee for National Mine Rescue and previously as a member of the Coal Safety Committee for the National Mining Association. In addition, Mr. Wynne is a past Chairman of the Kentucky Coal Association. Mr. Wynne holds a Bachelor of Science degree in Mining Engineering from the University of Pittsburgh and a Master of Business Administration degree from West Virginia University.

Nick Carter became a Director in April 2015. Mr. Carter is a member of the Audit, Compensation and Conflicts Committees. Mr. Carter retired as President and Chief Operating Officer of Natural Resource Partners L.P. (NYSE: NRP) on September 1, 2014, having served in such capacities since 2002 and in other roles for NRP or its affiliates since 1990. Prior to 1990, Mr. Carter held various positions with MAPCO Coal Corporation and was engaged in the private practice of law. Mr. Carter also serves on the board of directors, the audit committee and as chairman of the compensation committee of Community Trust Bancorp, Inc. (NASDAQ: CTBI). Mr. Carter previously served as chairman of the National Council of Coal Lessors for 12 years and as chairman of the West Virginia Chamber of Commerce. He also previously served as a board member of the West Virginia Coal Association, the Indiana Coal Council, the National Mining Association, and ACCCE. Mr. Carter has served as a board member of the Kentucky Coal Association for over 20 years and currently is its Treasurer. Mr. Carter holds Bachelor and Juris Doctorate degrees from the University of Kentucky and a Master of Business Administration degree from the University of Hawaii. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Carter should serve as a Director include his extensive experience in the coal and energy industries and in senior corporate leadership.

Robert J. Druten became a Director effective January 1, 2019. Mr. Druten is Chairman of the Conflicts Committee and is a member of the Audit and Compensation Committees. From January 2007 through 2018, Mr. Druten was a member of the board of directors of Alliance GP, LLC, the former general partner of AHGP. From September 1994 until his retirement in August 2006, Mr. Druten served as Executive Vice President and Chief Financial Officer of Hallmark Cards, Inc. Mr. Druten holds a Bachelor of Science degree in Accounting from the University of Kansas as well as a Masters of Business Administration from Rockhurst University. Mr. Druten currently serves as Chairman of the Board of Directors of Kansas City Southern Industries, Inc. (NYSE: KSU), a transportation and financial services company, and is Chairman of its executive committee, and is a member of its compensation committee and nominating and governance committees. Mr. Druten is also a Trustee and Chairman of the Board of Entertainment Properties Trust (NYSE: EPR), a real estate investment trust focused on the acquisition of movie theatre complexes and other entertainment related properties, and is a member of its audit, compensation, finance and governance committees. Mr. Druten previously served as a director of American Italian Pasta, from 2007 until it was acquired by Ralcorp Holdings in July, 2010, where he was the Chair of the Audit Committee and also served on the Compensation Committee. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Druten should serve as Director are demonstrated by his lengthy and distinguished service as Chief Financial Officer of Hallmark, including direct oversight of a public company subsidiary, and his extensive experience serving as a director of public companies in multiple industries.

John H. Robinson became a Director in December 1999. Mr. Robinson is Chairman of the Compensation Committee and a member of the Audit and Conflicts Committees. Mr. Robinson is Chairman of Hamilton Ventures, LLC. From 2003 to 2004, he was Chairman of EPC Global, Ltd., an engineering staffing company. From 2000 to 2002, he was Executive Director of Amey plc, a British business process outsourcing company. Mr. Robinson served as Vice Chairman of Black & Veatch, Inc. from 1998 to 2000. He began his career at Black & Veatch in 1973 and was a General Partner and Managing Partner prior to becoming Vice Chairman when the firm incorporated. Mr. Robinson is a Director of Coeur Mining Corporation and a member of its executive and audit committees and chairman of its compensation committee. Mr. Robinson is also a Director of Olsson Associates. He holds Bachelor and Master of Science degrees in Engineering from the University of Kansas and is a graduate of the Owner-President-Management Program at the Harvard Business School. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Robinson should serve as a Director include his significant experience in the engineering and consulting industries, his extensive service in senior corporate leadership positions in both industries and his familiarity with financial matters.

Wilson M. Torrence became a Director in January 2007. Mr. Torrence is Chairman of the Audit Committee and a member of the Compensation Committee. From April 2015 through June 2018, Mr. Torrence was also a member of the board of directors of Alliance GP, LLC, the former general partner of AHGP, and chairman of its audit committee. Mr. Torrence retired from Fluor Corporation in 2006 as a Senior Vice President of Project Development and Investments and after retirement has performed investment and business consulting services for various clients. Mr. Torrence was employed at Fluor from 1989 to 2006 where, among other roles, he was responsible for the global Project Investment and Structured Finance Group and served as Chairman of Fluor's Investment Committee. In that position, Mr. Torrence had executive responsibility for Fluor's global activities in developing and arranging third-party financing for some of Fluor's clients' construction projects. Prior to joining Fluor in 1989, Mr. Torrence was President and CEO of Combustion Engineering Corporation's Waste to Energy Division and, during that time, also served as Chairman of the Institute of Resource Recovery, a Washington-based industry advocacy organization. Mr. Torrence began his career at Mobil Oil Corporation, where he held several executive positions, including Assistant Treasurer of Mobil's International Marketing and Refining Division and Chief Financial and Planning Officer of Mobil Land Development Company. Mr. Torrence holds a Bachelor and a Master of Business Administration degree from Virginia Tech University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Torrence should serve as a Director include his extensive experience in the construction and energy businesses, his senior corporate finance-related and other leadership positions and his participation in numerous financing transactions.

Board of Directors

Mr. Craft, who has been President and CEO and a member of the Board of Directors since ARLP's inception, assumed the Chairman role effective January 1, 2019 following the retirement of Mr. John P. Neafsey, who served as Chairman from ARLP’s inception through 2018. We believe this leadership structure of the Board of Directors is appropriate for the Partnership given Mr. Craft's extensive knowledge of our industry, significant ownership position and proven leadership of the Partnership.

The Board of Directors generally administers its risk oversight function through the board as a whole. The Chairman, President and CEO, who reports to the Board of Directors, and the other executives named above, who report to the Chairman, President and CEO, have day-to-day risk management responsibilities. At the Board of Directors' request, each of these executives attends the meetings of the Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations and our safety performance, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, management provides periodic reports of the Partnership's financial and operational performance to each member of the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership's internal auditor, who reports directly to the Audit Committee, and reviews the Partnership's contingencies, significant transactions and subsequent events, among other matters, with management and our independent auditors.

The Board of Directors has selected as director nominees individuals with experience, skills and qualifications relevant to the business of the Partnership, such as experience in energy or related industries or with financial markets, expertise in mining, engineering or finance, and a history of service in senior leadership positions. The Board of Directors has not established a formal process for identifying director nominees, nor does it have a formal policy regarding consideration of diversity in identifying director nominees, but has endeavored to assemble a diverse group of individuals with the qualities and attributes required to provide effective oversight of the Partnership.

Audit Committee

The Audit Committee comprises all four non-employee members of the Board of Directors (Messrs. Carter, Druten, Robinson and Torrence). After reviewing the qualifications of the current members of the Audit Committee, and any relationships they may have with us that might affect their independence, the Board of Directors has determined that all current Audit Committee members are "independent" as that concept is defined in Section 10A of the Exchange Act, all current Audit Committee members are "independent" as that concept is defined in the applicable rules of NASDAQ Stock Market, LLC, all current Audit Committee members are financially literate, and Mr. Torrence qualifies as an "audit committee financial expert" under the applicable rules promulgated pursuant to the Exchange Act.

Report of the Audit Committee

The Audit Committee oversees our financial reporting process on behalf of the Board of Directors. Management has primary responsibility for the financial statements and the reporting process including the systems of internal controls. The Audit Committee has responsibility for the appointment, compensation and oversight of the work of our independent registered public accounting firm and assists the Board of Directors by conducting its own review of our:

- filings with the SEC pursuant to the Securities Act and the Exchange Act (i.e., Forms 10-K, 10-Q, and 8-K);

- press releases and other communications by us to the public concerning earnings, financial condition and results of operations, including changes in distribution policies or practices affecting the holders of our units, if such review is not undertaken by the Board of Directors;

- systems of internal controls regarding finance and accounting that management and the Board of Directors have established; and

- auditing, accounting and financial reporting processes generally.

In fulfilling its oversight and other responsibilities, the Audit Committee met eight times during 2019. The Audit Committee's activities included, but were not limited to: (a) selecting the independent registered public accounting firm, (b) meeting periodically in executive session with the independent registered public accounting firm, (c) reviewing the Quarterly Reports on Form 10-Q for the three months ended March 31, June 30, and September 30, 2019, (d) performing a self-assessment of the committee, (e) reviewing the Audit Committee charter, and (f) reviewing the overall scope, plans and findings of our internal auditor. Based on the results of the annual self-assessment, the Audit Committee believes that it satisfied the requirements of its charter. The Audit Committee also reviewed and discussed with management and the independent registered public accounting firm this Annual Report on Form 10-K, including the audited financial statements.

Our independent registered public accounting firm, Ernst & Young LLP ("EY"), is responsible for expressing an opinion on the conformity of the audited financial statements with GAAP. The Audit Committee reviewed with EY its judgment as to the quality, not just the acceptability, of our accounting principles and such other matters as are required to be discussed with the Audit Committee pursuant to the applicable requirements of the Public Company Accounting Oversight Board ("PCAOB") and the SEC.

The Audit Committee received written disclosures and the letter from EY required by applicable requirements of the PCAOB Rule 3526, "Communication with Audit Committees Concerning Independence," and has discussed with EY its independence from management and the ARLP Partnership.

Based on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2019 for filing with the SEC.

Members of the Audit Committee:

Wilson M. Torrence, Chairman
Nick Carter
Robert J. Druten
John H. Robinson

Code of Ethics

We have adopted a code of ethics with which the Chairman, President and CEO and the senior financial officers (including the principal financial officer and the principal accounting officer) are expected to comply. The code of ethics is publicly available on our website under "Investor Relations" at www.arlp.com and is available in print without charge to any unitholder who requests it. Such requests should be directed to Investor Relations at (918) 295-7674. If any substantive amendments are made to the code of ethics or if there is a grant of a waiver, including any implicit waiver, from a provision of the code to the President and CEO, Chief Financial Officer, or Controller, we will disclose the nature of such amendment or waiver on our website or in a report on Form 8-K.

Communications with the Board

Unitholders or other interested parties can contact any director or committee of the Board of Directors by writing to them c/o Senior Vice President, General Counsel and Secretary, P.O. Box 22027, Tulsa, Oklahoma 74121-2027. Comments or complaints relating to our accounting, internal accounting controls or auditing matters will also be referred to members of the Audit Committee. The Audit Committee has procedures for (a) receipt, retention and treatment of complaints received by us regarding accounting, internal accounting controls, or auditing matters and (b) the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, as amended, requires directors, executive officers and persons who beneficially own more than ten percent 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. Based upon a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that during 2019 none of our directors or executive officers or persons who beneficially owned more than ten percent of a registered class of our equity securities were delinquent with respect to any of the filing requirements under Section 16(a).

Reimbursement of Expenses of our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation in connection with its management of us. Our general partner is reimbursed by us for all expenses incurred on our behalf. Please see "Item 13. Certain Relationships and Related Transactions, and Director Independence—*Administrative Services*."

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Introduction

The Compensation Committee oversees the compensation of our general partner's executive officers, including the Chairman, President and CEO, our principal executive officer, the Senior Vice President and Chief Financial Officer, our principal financial officer, and the three most highly compensated executive officers in 2019, each of whom is named in the Summary Compensation Table (collectively, our "Named Executive Officers"). Our Named Executive Officers are employees of our operating subsidiary, Alliance Coal.

Compensation Objectives and Philosophy

The compensation of our Named Executive Officers is designed to achieve two key objectives: (i) provide a competitive compensation opportunity to allow us to recruit and retain key management talent, and (ii) motivate and reward the executive officers for creating sustainable, capital-efficient growth in available cash to maximize our distributions to our unitholders. In making decisions regarding executive compensation, the Compensation Committee reviews current compensation levels of other companies in the coal industry and other peers, considers the Chairman, President and CEO's assessment of each of the other executives, and uses its discretion to determine an appropriate total compensation package of base salary and short-term and long-term incentives. The Compensation Committee intends for each executive officer's total compensation to be competitive in the marketplace and to effectively motivate the officer. Based upon its review of our overall executive compensation program, the Compensation Committee believes the program is appropriately applied to our general partner's executive officers and is necessary to attract and retain the executive officers who are essential to our continued development and success, to compensate those executive officers for their contributions and to enhance unitholder value. Moreover, the Compensation Committee believes the total compensation opportunities provided to our general partner's executive officers create alignment with our long-term interests and those of our unitholders. As a result, we do not maintain unit ownership requirements for our Named Executive Officers.

Setting Executive Compensation

We have not historically maintained employment agreements with any of our Named Executive Officers. We provided an employment letter to our Senior Vice President and Chief Strategic Officer, Mr. Tholen (the "Tholen Employment Letter"), in connection with his hiring in December 2019 setting forth the terms of his employment, which we determined were necessary to successfully hire Mr. Tholen and in the best interests of the Company. The Tholen Employment Letter provides for, among other things, (i) an initial annual base salary of $500,000.00, (ii) an award in 2019 under the LTIP having value on the grant date of $1 million and (iii) a one-time signing bonus of $1.5 million, which was paid or is payable in three equal cash installments of $500,000 in December 2019, 2020 and 2021, subject to Mr. Tholen's continued employment through such dates. The Tholen Employment Letter also provides that if Mr. Tholen’s employment is involuntarily terminated on or before December 31, 2022, other than for Good Cause (as defined in the Tholen Employment Letter), Mr. Tholen will receive a severance payment in an amount equal to (a) two times Mr. Tholen's then-effective annual base salary, plus (b) two times the then-effective standard payout for Mr. Tholen under the STIP, plus (c) any unpaid installment(s) of the one-time signing bonus described above, which amount shall be paid at the time of Mr. Tholen's termination of employment. The foregoing description of the Tholen Employment Letter does not purport to be complete and is qualified in its entirety by reference to the full and complete text of the Tholen Employment Letter, which is attached hereto as Exhibit 10.61.

Role of the Compensation Committee

The compensation committee of our general partner ("Compensation Committee") discharges the Board of Directors' responsibilities relating to our general partner's executive compensation program. The Compensation Committee oversees our compensation and benefit plans and policies, administers our incentive bonus and equity participation plans, and reviews and approves annually all compensation decisions relating to our Named Executive Officers. The Compensation Committee is empowered by the Board of Directors and by the Compensation Committee's charter to make all decisions regarding compensation for our Named Executive Officers without ratification or other action by the Board of Directors. The Compensation Committee has authority to secure services for executive compensation matters, legal advice, or other expert services, both from within and outside the company. While the Compensation Committee is empowered to delegate all or a portion of its duties to a subcommittee, it has not done so.

The Compensation Committee comprises all of our directors who have been determined to be "independent" by the Board of Directors in accordance with applicable NASDAQ Stock Market, LLC and SEC regulations, presently Messrs. Robinson, Carter, Druten and Torrence.

Role of Executive Officers

Each year, the Chairman, President and CEO submits recommendations to the Compensation Committee for adjustments to the salary, bonuses and long-term equity incentive awards payable to our Named Executive Officers, excluding himself. The Chairman, President and CEO bases his recommendations on his assessment of each executive's performance, experience, demonstrated leadership, job knowledge and management skills. The Compensation Committee considers the recommendations of the Chairman, President and CEO as one factor in making compensation decisions regarding our Named Executive Officers. Historically, and in 2019, the Compensation Committee and the Chairman, President and CEO have been substantially aligned on decisions regarding compensation of the Named Executive Officers. As executive officers are promoted or hired during the year, the Chairman, President and CEO makes compensation recommendations to the Compensation Committee and works closely with the Compensation Committee to ensure that all compensation arrangements for executive officers are consistent with our compensation philosophy and are approved by the Compensation Committee. At the direction of the Compensation Committee, the Chairman, President and CEO and the Senior Vice President, General Counsel and Secretary attend certain meetings of the Compensation Committee.

Use of Peer Group Comparisons

The Compensation Committee believes that it is important to review and compare our performance with that of peer companies in the coal industry, and reviews the composition of the peer group annually. The peer group for 2019 included Arch Coal, Inc., Consol Energy, Inc., Contura Energy, Inc., Natural Resource Partners L.P., Warrior Met Coal, Inc., and Peabody Energy Corporation. In assessing the competitiveness of our executive compensation program for 2019, the Compensation Committee, with the assistance of the Chairman, President and CEO, collected and analyzed peer group proxy information and developed a comparative analysis of base salaries, short-term incentives, total cash compensation, long-term incentives and total direct compensation. The Compensation Committee uses the peer group data as a point of reference for comparative purposes, but it is not the determinative factor for the compensation of our Named Executive Officers. The Compensation Committee exercises discretion in determining the nature and extent of the use of comparative pay data.

Consideration of Equity Ownership and CEO Compensation

Mr. Craft, the Chairman, President and CEO, is evaluated and treated differently with respect to compensation than our other Named Executive Officers. Mr. Craft and related entities own significant equity positions in ARLP and Mr. Craft indirectly owns our general partner. Because of these ownership positions, the interests of Mr. Craft are directly aligned with those of our unitholders. Mr. Craft has not received an increase in base salary since 2002, has not received a bonus under our short-term incentive plan ("STIP") since 2005 and did not receive any grants of LTIP awards from 2005 through 2015. On January 22, 2016, the Compensation Committee approved an LTIP award for Mr. Craft that vested on January 1, 2019. Mr. Craft has not received any subsequent LTIP awards. Beginning in February 2016, at Mr. Craft's request, his annual base salary was reduced to $1.

Compensation Components

Overview

The principal components of compensation for our Named Executive Officers (other than Mr. Craft) include:

- base salary;
- annual cash incentive bonus awards under the STIP; and
- awards of restricted units under the LTIP.

The relative amount of each component is not based on any formula, but rather is based on the recommendation of the Chairman, President and CEO, subject to the discretion of the Compensation Committee to make any modifications it deems appropriate.

Each of our Named Executive Officers (including Mr. Craft) also receives supplemental retirement benefits through the SERP. In addition, all executive officers are entitled to customary benefits available to our employees generally, including group medical, dental, and life insurance and participation in our profit sharing and savings plan ("PSSP"). Our PSSP is a defined contribution plan and includes an employer matching contribution of 75% on the first 3% of eligible compensation contributed by the employee, an employer non-matching contribution of 0.75% of eligible compensation, and an employer supplemental contribution of 5% of eligible compensation. The PSSP provides an additional means of attracting and retaining qualified employees by providing tax-advantaged opportunities for employees to save for retirement.

Base Salary

When reviewing base salaries, the Compensation Committee's policy is to consider the individual's experience, tenure and performance, the individual's level of responsibility, the position's complexity and its importance to us in relation to other executive positions, our financial performance, and competitive pay practices. The Compensation Committee also considers comparative compensation data of companies in our peer group and the recommendation of the Chairman, President and CEO of our general partner. Base salaries are reviewed annually to ensure continuing consistency with market levels, and adjustments to base salaries are made as needed to reflect movement in the competitive market as well as individual performance. During 2019, base salaries for our Named Executive Officers other than Mr. Craft and Mr. Tholen were increased as follows: Mr. Cantrell, from $284,000 to $304,000; Mr. Davis, from $325,000 to $345,000; and Mr. Wynne, from $374,000 to $404,000.

Annual Cash Incentive Bonus Awards

The STIP is designed to assist us in attracting, retaining and motivating qualified personnel by rewarding management, including our Named Executive Officers, and selected other salaried employees with cash awards for our achievement of an annual financial performance target. The annual performance target is recommended by the Chairman, President and CEO and approved by the Compensation Committee, typically in January of each year. The performance measure is subject to equitable adjustment in the sole discretion of the Compensation Committee to reflect the occurrence of any significant events during the year.

The performance target historically has been EBITDA-based, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the operating results of our core business. (EBITDA is defined as net income of ARLP before net interest expense, income taxes, depreciation, depletion and amortization and net income attributable to noncontrolling interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target, and it increases in relationship to our EBITDA, as adjusted, exceeding the minimum threshold. The Compensation Committee may determine satisfactory results and adjust the size of the pay-out pool in its sole discretion. In 2019, the Compensation Committee approved a minimum financial performance target of $525.5 million in EBITDA from current operations, normalized by excluding any charges for unit-based and directors' compensation and affiliate contributions, if any. For 2019, we exceeded the minimum performance target.

Awards to our Named Executive Officers each year are determined by and in the discretion of the Compensation Committee. However, the Compensation Committee does not establish individual target payout amounts for the Named Executive Officers' STIP awards. As it does when reviewing base salaries, in determining individual awards under the STIP, the Compensation Committee considers its assessment of the individual's performance, our financial performance, comparative compensation data of companies in our peer group and the recommendation of the Chairman, President and CEO, although EBITDA-based performance targets described above are given significant weight. The compensation expense associated with STIP awards is recognized in the year earned, with the cash awards generally payable in the first quarter of the following calendar year. Termination of employment of an executive officer for any reason prior to payment of a cash award will result in forfeiture of any right to the award, unless and to the extent waived by the Compensation Committee in its discretion.

The performance measure for the STIP in 2020 will be EBITDA for current operations, excluding charges for unit-based and directors' compensation. As discussed above, the Compensation Committee may, in its discretion, make equitable adjustments to the performance criteria under the STIP and adjust the amount of the aggregate pay-out. The Compensation Committee believes the STIP performance criteria for 2020 will be reasonably difficult to achieve and therefore support our key compensation objectives discussed above.

Equity Awards under the LTIP

Equity compensation pursuant to the LTIP is a key component of our executive compensation program. Our LTIP is sponsored by Alliance Coal. Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. The Compensation Committee has authority to determine the participants to whom restricted units are granted, the number of restricted units to be granted to each such participant, and the conditions under which the restricted units may become vested, including the duration of any vesting period. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our general partner's Chairman, President and CEO, subject to review and approval by the Compensation Committee. Grant levels are intended to support the objectives of the comprehensive compensation package described above. The LTIP grants provide our Named Executive Officers with the opportunity to achieve a meaningful ownership stake in the Partnership, thereby assuring that their interests are aligned with our success. Even though Mr. Craft was not granted an award under the LTIP from 2005 through 2019 with the exception of one grant in 2016, the Compensation Committee believes Mr. Craft's interests are directly aligned with the interests of our unitholders as a result of his ownership positions. There is no formula for determining the size of awards to any individual recipient and, as it does when reviewing base salaries and individual STIP payments, the Compensation Committee considers its assessment of the individual's performance, our financial performance, compensation levels at peer companies in the coal industry and the recommendation of the Chairman, President and CEO. Amounts realized from prior grants, including amounts realized due to changes in the value of our common units, are not considered in setting grant levels or other compensation for our Named Executive Officers.

Restricted Units. Restricted units granted under the LTIP are "phantom" or notional units that upon vesting entitle the participant to receive an ARLP common unit. Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. However, if a grantee's employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will be automatically forfeited, unless the Compensation Committee, in its sole discretion, determines otherwise. The number of units actually distributed upon satisfaction of the applicable vesting requirements is reduced to cover the income tax withholding requirement for each individual participant based upon the fair market value of the common units as of the date of distribution. At the Compensation Committee's discretion, grants of restricted units under the LTIP may include the contingent right to receive quarterly distributions in an amount equal to the cash distributions we make to unitholders during the vesting period ("DERs"). DERs are payable, in the discretion of the Compensation Committee, either in cash or in the form of additional Restricted Units credited to a book keeping account subject to the same vesting restrictions as the tandem award.

The performance target applicable to restricted unit awards under the LTIP is based on a normalized EBITDA measure, with that measure typically being similar to the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. We typically issue grants under the LTIP at the beginning of each year, with the exceptions of new employees who begin employment with us at some other time and job promotions that may occur at some other time. The compensation expense associated with LTIP grants is recognized over the vesting period in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 718, *Compensation — Stock Compensation*.

Our general partner's policy is to grant restricted units pursuant to the LTIP to serve as a means of incentive compensation for performance. Therefore, no consideration will be payable by the LTIP participants upon receipt of the common units. Common units to be delivered upon the vesting of restricted units may be common units we already own, common units we acquire in the open market or from any other person, newly issued common units, or any combination of the foregoing. If we issue new common units upon payment of the restricted units instead of purchasing them, the total number of common units outstanding will increase.

Grants for 2019 under the LTIP, made January 23, 2019, will cliff vest on January 1, 2022, provided we achieve a target level of aggregate EBITDA for current operations, excluding any charges for unit-based and directors' compensation, for the period January 1, 2019 through December 31, 2021. Grants for 2020 under the LTIP, made January 22, 2020, will cliff vest on January 1, 2023, provided we achieve a target level of aggregate EBITDA for current operations, excluding any charges for unit-based and directors' compensation, for the period January 1, 2020 through December 31, 2022. The LTIP provides the Compensation Committee with discretion to determine the conditions for vesting (as well as all other terms and conditions) associated with any award under the plan, and to amend any of those conditions so long as an amendment does not materially reduce the benefit to the participant. The Compensation Committee believes the performance-related vesting conditions of all outstanding awards under the LTIP will be reasonably difficult to satisfy and therefore support our key compensation objectives discussed above.

Unit Options. We have not made any grants of unit options. The Compensation Committee, in the future, may decide to make unit option grants to employees and directors on terms determined by the Compensation Committee.

Grant Timing. The Compensation Committee does not time, nor has the Compensation Committee in the past timed, the grant of LTIP awards in coordination with the release of material non-public information. Instead, LTIP awards are granted only at the time or times dictated by our normal compensation process as developed by the Compensation Committee.

Effect of a Change in Control. Upon a "change in control" as defined in the LTIP, all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. Please see "Item 11. Executive Compensation—*Potential Payments Upon a Termination or Change of Control*."

Amendments and Termination. The Board of Directors or the Compensation Committee may, in its discretion, terminate the LTIP at any time with respect to any common units for which a grant has not previously been made. Except as required by the rules of the exchange on which the common units may be listed at that time, the Board of Directors or the Compensation Committee may alter or amend the LTIP in any manner from time to time; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the affected participant. In addition, the Board of Directors or the Compensation Committee may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward our employees.

Supplemental Executive Retirement Plan

We maintain the SERP to help attract and motivate key employees, including our Named Executive Officers. The SERP is sponsored by Alliance Coal. Participation in the SERP aligns the interest of each Named Executive Officer with the interests of our unitholders because all allocations made to participants under the SERP are made in the form of notional common units of ARLP, defined in the SERP as "phantom units." The Compensation Committee approves the SERP participants and their percentage allocations, and can amend or terminate the SERP at any time. All of our Named Executive Officers currently participate in the SERP.

Under the terms of the SERP, a participant is entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of the participant's base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions, which are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination from employment in ARLP common units equal to the number of phantom units then credited to the participant's account, less the number of units required to satisfy our tax withholding obligations. A participant in the SERP is not entitled to an allocation for the year in which his termination from employment occurs, except as described below.

A participant in the SERP, including any of our Named Executive Officers, is entitled to receive an allocation under the SERP for the year in which his employment is terminated only if such termination results from one of the following events:

(1) the participant's employment is terminated other than for "cause";

(2) the participant terminates employment for "good reason";

(3) a change of control of us or our general partner occurs and, as a result, the participant's employment is terminated (whether voluntary or involuntary);

(4) death of the participant;

(5) the participant attains (or has attained) retirement age of 65 years; or

(6) the participant incurs a total and permanent disability, which shall be deemed to occur if the participant is eligible to receive benefits under the terms of the long-term disability program we maintain.

This allocation for the year in which a participant's termination occurs shall equal the participant's eligible compensation for such year (including any severance amount, if applicable) multiplied by his percentage allocation under the SERP, reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year.

Other Compensation-Related Matters

Trading in Derivatives

It is our general partner's policy that directors and all officers, including the Named Executive Officers, may not purchase or sell options on ARLP's common units.

Tax Deductibility of Compensation

The deduction limitations imposed under Section 162(m) of the Internal Revenue Code do not apply to compensation paid to our Named Executive Officers because we are a limited partnership and not a "corporation" within the meaning of Section 162(m).

Perquisites and Personal Benefits

The Partnership provides a limited amount of perquisites and personal benefits to the Named Executive Officers in keeping with the Compensation Committee's objectives to provide competitive compensation to motivate and reward executive officers for creating sustainable, capital-efficient growth in available cash. These perquisites and personal benefits typically include amounts for items such as tax preparation fees and social club dues, and are reviewed annually by the Compensation Committee.

Compensation Committee Report

The Compensation Committee has submitted the following report for inclusion in this Annual Report on Form 10-K:

Our Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K with management. Based on our Compensation Committee's review of and the discussions with management with respect to the Compensation Discussion and Analysis, our Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

The foregoing report is provided by the following directors, who constitute all the members of the Compensation Committee:

Members of the Compensation Committee:

John H. Robinson, Chairman
Nick Carter
Robert J. Druten
Wilson M. Torrence

Notwithstanding anything to the contrary set forth in any of our previous filings under the Securities Act or the Exchange Act, that incorporate future filings, including this Annual Report on Form 10-K, in whole or in part, the foregoing Compensation Committee Report shall not be deemed to be filed with the SEC or incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that we specifically incorporate it by reference.

Summary Compensation Table

Name and Principal Position	Year	Salary (1)	Bonus (2)	Unit Awards (3)	Non-Equity Incentive Plan Compensation (4)	All Other Compensation (5)	Total
Joseph W. Craft III	2019	$ 1	$ —	$ —	$ —	$ 12,962	$ 12,963
President, Chief Executive	2018	1	—	—	—	12,462	12,463
Officer and Chairman	2017	1	—	—	—	11,951	11,952
Brian L. Cantrell,	2019	299,846	—	529,161	213,000	66,612	1,108,619
Senior Vice President and	2018	284,000	—	486,438	385,000	56,190	1,211,628
Chief Financial Officer	2017	284,000	—	487,483	242,000	58,832	1,072,315
R. Eberley Davis	2019	341,154	—	673,993	274,000	86,768	1,375,915
Senior Vice President,	2018	325,000	—	619,568	530,000	61,275	1,535,843
General Counsel and Secretary	2017	325,000	—	587,644	277,000	69,727	1,259,371
Kirk D. Tholen (6)	2019	—	500,000	1,016,237	83,000	69,978	1,669,215
Senior Vice President and							
Chief Strategic Officer							
Thomas M. Wynne	2019	398,231	—	774,261	280,000	80,287	1,532,779
Senior Vice President and	2018	374,000	—	711,756	500,000	62,506	1,648,262
Chief Operating Officer	2017	374,000	—	710,264	319,000	71,185	1,474,449

(1) In recent years, certain of our Named Executive Officers devoted a portion of their time to the business of one or more related parties and, to the extent they did so, the base salary of those executive officers was reimbursed to Alliance Coal by those related parties pursuant to an administrative services agreement. Please see "Item 1. Business—Employees—*Administrative Services Agreement*." In 2019, Alliance Coal was not reimbursed base salary for any of our NEOs. In 2018, prior to the Simplification Transactions on May 31, 2018, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 5% for Mr. Cantrell and 8% for Mr. Davis. Please see "Item 1. Business—Partnership Simplification" for more information on the Simplification Transactions. In 2017, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 6% for Mr. Cantrell and 9% for Mr. Davis.

(2) The discretionary bonus paid to Mr. Tholen in 2019 represents the first installment of his signing bonus. Please see "Item 11. Compensation Discussion and Analysis—*Setting Executive Compensation*" for a description of the terms of Mr. Tholen's employment.

(3) The Unit Awards represent the aggregate grant date fair value of equity awards granted (computed in accordance with FASB ASC 718, using the same assumptions as used for financial reporting purposes, more fully described in "Item 8. Financial Statements and Supplementary Data—Note 16 – Compensation Plans") to each Named Executive Officer

under the LTIP in the respective year. Please see "Item 11. Compensation Discussion and Analysis—Compensation Program Components—*Equity Awards under the LTIP*" for a description of the terms of the awards.

(4) Amounts represent the STIP bonus earned for the respective year. STIP payments are made in the first quarter of the year following the year in which they are earned. Please see "Item 11. Compensation Discussion and Analysis—Compensation Program Components—*Annual Cash Incentive Bonus Awards*."

(5) For all Named Executive Officers, the amounts represent the sum of the (a) SERP phantom unit contributions valued at the market closing price of our common units on the date the phantom unit was granted, (b) profit sharing savings plan employer contribution and (c) perquisites in excess of $10,000. A reconciliation of the 2019 amounts shown is as follows:

	SERP	Profit Sharing Plan Employer Contribution	Perquisites (a)	Total
Joseph W. Craft III	$ —	$ 1	$ 12,961	$ 12,962
Brian L. Cantrell	32,611	22,400	11,601	66,612
R. Eberley Davis	64,368	22,400	—	86,768
Kirk D. Tholen	49,675	—	20,303	69,978
Thomas M. Wynne	57,887	22,400	—	80,287

a) For Mr. Craft, perquisites and other personal benefits comprised of club dues of $12,961. For Mr. Cantrell, perquisites and other personal benefits totaling $11,601 comprised of club dues of $9,951 and other perquisites of $1,650. For Mr. Tholen, perquisites and other personal benefits comprised of relocation related expenses of $20,303.

(6) Mr. Tholen began employment and became a Named Executive Officer on December 23, 2019, therefore compensation for 2018 and 2017 is not presented in the table.

Grants of Plan-Based Awards Table

Name	Grant Date	Approved Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold (3)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Target (4)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Maximum (3)	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (5)	Estimated Future Payouts Under Equity Incentive Plan Awards Target (6)	Estimated Future Payouts Under Equity Incentive Plan Awards Maximum (5)	All Other Unit Awards: Number of Units (7)	Grant Date Fair Value of Unit Awards (8)
Joseph W. Craft III	February 4, 2019	February 4, 2019					—		—	$ —
	February 14, 2019	(1), (2)					—		6,479	124,008
	May 15, 2019	(1), (2)					—		6,891	127,208
	August 14, 2019	(1), (2)					—		8,210	120,277
	November 14, 2019	(1), (2)					—		11,538	137,764
	December 31, 2019	(2)					—		—	—
	January 23, 2019	February 8, 2020		$ —			—		—	—
				—			—		33,118	509,257
Brian L. Cantrell	February 4, 2019	February 4, 2019					26,551		—	529,161
	February 14, 2019	(1), (2)					—		652	12,479
	May 15, 2019	(1), (2)					—		694	12,811
	August 14, 2019	(1), (2)					—		827	12,116
	November 14, 2019	(1), (2)					—		1,162	13,874
	December 31, 2019	(2)					—		3,014	32,611
	January 23, 2019	February 8, 2020		213,000			—		—	—
				213,000			26,551		6,349	613,052
R. Eberley Davis	February 4, 2019	February 4, 2019					33,818		—	673,993
	February 14, 2019	(1), (2)					—		875	16,748
	May 15, 2019	(1), (2)					—		931	17,186
	August 14, 2019	(1), (2)					—		1,109	16,247
	November 14, 2019	(1), (2)					—		1,558	18,603
	December 31, 2019	(2)					—		5,949	64,368
	January 23, 2019	February 8, 2020		274,000			—		—	—
				274,000			33,818		10,422	807,145
Kirk D. Tholen	December 23, 2019	December 23, 2019					95,511		—	1,016,237
	February 14, 2019	(1), (2)					—		—	—
	May 15, 2019	(1), (2)					—		—	—
	August 14, 2019	(1), (2)					—		—	—
	November 14, 2019	(1), (2)					—		—	—
	December 31, 2019	(2)					—		4,591	49,675
	January 23, 2019	February 8, 2020		83,000			—		—	—
				83,000			95,511		4,591	1,065,912
Thomas M. Wynne	February 4, 2019	February 4, 2019					38,849		—	774,261
	February 14, 2019	(1), (2)					—		901	17,245
	May 15, 2019	(1), (2)					—		959	17,703
	August 14, 2019	(1), (2)					—		1,142	16,730
	November 14, 2019	(1), (2)					—		1,605	19,164
	December 31, 2019	(2)					—		5,350	57,887
	January 23, 2019	February 8, 2020		280,000			—		—	—
				$ 280,000			38,849		9,957	$ 902,990

(1) In accordance with the provisions of the SERP, a participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions when we pay a distribution to our common unitholders, which is added to the account balance in the form of phantom units.

(2) These contributions are made in accordance with the SERP plan document that has been approved by the Compensation Committee. Therefore, these contributions are not separately approved by the Compensation Committee.

(3) Awards under our STIP are subject to a minimum financial performance target each year. However, determination of individual awards under the STIP is based upon an assessment of the Named Executive Officer's performance, comparative compensation data of companies in our peer group and recommendation of the Chairman, President and CEO. The STIP does not specify any threshold or maximum payout amounts. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Annual Cash Incentive Bonus Awards*" for additional information regarding the STIP awards.

(4) These amounts represent awards pursuant to our STIP. On January 23, 2019, the Compensation Committee set the EBITDA target amount for use in determining the total plan payout. The discretionary payout allocations to all participating employees is determined after the year is completed. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Annual Cash Incentive Bonus Awards*" for additional information regarding the STIP awards.

(5) Grants of restricted units under our LTIP are not subject to minimum thresholds, targets or maximum payout conditions. However, the vesting of these grants is subject to the satisfaction of certain performance criteria. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*."

(6) These awards are grants of restricted units pursuant to our LTIP. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*."

(7) These awards are phantom units added to each Named Executive Officer's SERP notional account balance. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*."

(8) We calculated the fair value of LTIP awards to our NEOs, with the exception of Mr. Tholen, using a value of $19.93 per unit, the unit price applicable to our February 2019 grants. We calculated the fair value of the LTIP award to Mr. Tholen using a value of $10.64 per unit, the price applicable to his December 2019 grant. We calculated the fair value of SERP phantom unit awards using the market closing price on the date the phantom unit award was granted. Phantom units granted under the SERP vest on the date granted.

Narrative Disclosure Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Cash Incentive Bonus Awards

Under the STIP, our Named Executive Officers are eligible for cash awards for our achieving an annual financial performance target. The annual performance target is recommended by the Chairman, President and CEO of our general partner and approved by the Compensation Committee, typically in January of each year. The performance target historically has been EBITDA-based, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the pure operating results of our core business. (EBITDA is calculated as net income attributable to ARLP before net interest expense, income taxes and depreciation, depletion and amortization.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target. The cash available generally increases in relationship to our EBITDA, as adjusted, exceeding the minimum financial performance target and is subject to adjustment by the Compensation Committee in its discretion. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Annual Cash Incentive Bonus Awards*."

Long-Term Incentive Plan

Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our general partner's Chairman, President and CEO, subject to the review and approval of the Compensation Committee. Restricted units granted under the LTIP are "phantom" or notional units that upon vesting entitle the participant to receive an ARLP unit. Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. The performance target is based on a normalized EBITDA measure, with that measure typically being similar to the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*."

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination or death in ARLP common units equal to the number of phantom units then credited to the participant's account, subject to reduction of the number of units distributed to cover withholding obligations. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*."

Salary and Bonus in Proportion to Total Compensation

The following table shows the total of salary and bonus in proportion to total compensation from the Summary Compensation Table:

Name	Year	Salary and Bonus ($) (1)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation (1)
Joseph W. Craft III	2019	$ 1	$ 12,963	0.0%
Brian L. Cantrell	2019	299,846	1,108,619	27.0%
R. Eberley Davis	2019	341,154	1,375,915	24.8%
Kirk D. Tholen	2019	500,000	1,669,215	30.0%
Thomas M. Wynne	2019	398,231	1,532,779	26.0%

(1) Percentages were calculated using the base salary and discretionary bonus of the NEOs. The only discretionary bonus we provided to our NEOs in 2019 was to Mr. Tholen as part of his signing bonus. Incentive awards paid pursuant to our STIP are deemed to be performance-based non-equity incentive compensation awards and are not included within the discretionary bonus amounts.

Outstanding Equity Awards at 2019 Fiscal Year End Table

Name	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (1)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested (2)
Joseph W. Craft III	—	$ —
Brian L. Cantrell	71,363	772,148
R. Eberley Davis	89,464	968,001
Kirk D. Tholen	95,511	1,033,429
Thomas M. Wynne	104,288	1,128,396

(1) Amounts represent restricted units awarded under the LTIP that were not vested as of December 31, 2019. Subject to our achieving financial performance targets, the units vested, or will vest, as follows:

Name	January 1, 2020	January 1, 2021	January 1, 2022
Joseph W. Craft III	—	—	—
Brian L. Cantrell	20,967	23,845	26,551
R. Eberley Davis	25,275	30,371	33,818
Kirk D. Tholen	—	—	95,511
Thomas M. Wynne	30,549	34,890	38,849

Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*." All grants of restricted units under the LTIP include the contingent right to receive quarterly cash distributions in an amount equal to the cash distributions we make to unitholders during the vesting period.

(2) Stated values are based on $10.82 per unit, the closing price of our common units on December 31, 2019, the final market trading day of 2019.

Units Vested Table for 2019

	Unit Awards		
Name	**Number of Units Acquired on Vesting (1)**		**Value Realized on Vesting (1)**
Joseph W. Craft III	78,555	$	1,362,144
Brian L. Cantrell	39,300		681,462
R. Eberley Davis	47,200		818,448
Kirk D. Tholen	—		—
Thomas M. Wynne	57,750		1,001,385

(1) Amounts represent the number and value of restricted units granted under the LTIP that vested in 2019. All of these units vested on January 1, 2019 and are valued at $17.34 per unit, the closing price on December 31, 2018, the final market trading day of 2018. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*."

Nonqualified Deferred Compensation Table for 2019

Name		Executive Contributions in Last Fiscal Year ($) (1)		Registrant Contributions in Last Fiscal Year ($) (2)		Aggregate Earnings in Last Fiscal Year ($) (3)		Aggregate Withdrawals in Last Fiscal Year ($) (1)		Aggregate Balance at Last Fiscal Year End ($) (4)
Joseph W. Craft III	$	—	$	—	$	(1,178,121)	$	—	$	2,908,102
Brian L. Cantrell		—		32,611		(118,556)		—		325,325
R. Eberley Davis		—		64,368		(159,075)		—		457,069
Kirk D. Tholen		—		49,675		—		—		49,675
Thomas M. Wynne		—		57,887		(163,793)		—		462,274

(1) Column not applicable.

(2) Amounts represent awards of phantom units contributed to each Named Executive Officer's SERP notional account balance. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*." These amounts have also been included within the "All Other Compensation" column of the Summary Compensation Table for the 2019 year.

(3) Amounts represent earnings accrued during 2019 on each Named Executive Officer's SERP notional account balance for additional phantom units as a result of quarterly distributions on our common units and changes in the market value of the notional account balance. Earnings were not above-market or preferential.

(4) Amounts represent the Named Executive Officer's cumulative notional account balance of phantom units valued at $10.82, the closing price of our common units on December 31, 2019, the final market trading day of 2019. The amounts include aggregate phantom unit quarterly distributions, changes in market value and the following aggregate

amounts contributed since inception to each Named Executive Officer's SERP notional account balance including the amounts contributed in the last fiscal year shown in the table above: Mr. Craft, $670,927; Mr. Cantrell, $343,928; Mr. Davis, $534,018; Mr. Tholen; $49,675; and Mr. Wynne, $456,889.

Narrative Discussion Relating to the Nonqualified Deferred Compensation Table for 2019

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to their percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination or death in ARLP common units equal to the number of phantom units then credited to the participant's account, subject to reduction of the number of units distributed to cover withholding obligations. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*."

Potential Payments Upon a Termination or Change of Control

Each of our Named Executive Officers is eligible to receive accelerated vesting and payment under the LTIP and the SERP upon certain terminations of employment or upon our change in control. Upon a "change of control," as defined in the LTIP, all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. In this regard, all restricted periods shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level. The LTIP defines a "change in control" as one of the following events: (1) any sale, lease, exchange or other transfer of all or substantially all of our assets or Alliance Coal's assets to any person other than a person who is our affiliate; (2) the consolidation or merger of Alliance Coal with or into another person pursuant to a transaction in which the outstanding voting interests of Alliance Coal are changed into or exchanged for cash, securities or other property, other than any such transaction where (a) the outstanding voting interests of Alliance Coal are changed into or exchanged for voting stock or interests of the surviving corporation or its parent and (b) the holders of the voting interests of Alliance Coal immediately prior to such transaction own, directly or indirectly, not less than a majority of the voting stock or interests of the surviving corporation or its parent immediately after such transaction; or (3) a person or group being or becoming the beneficial owner of more than 50% of all voting interests of Alliance Coal then outstanding.

The amounts each of our Named Executive Officers could receive under the SERP have been previously disclosed in "Item 11. Nonqualified Deferred Compensation Table for 2019" and the amounts each of the Named Executive Officers could receive under the LTIP have been previously disclosed in "Item 11. Outstanding Equity Awards at 2019 Fiscal Year End Table", in each case assuming the triggering event occurred on December 31, 2019. In addition, if a Named Executive Officer's employment were terminated as a result of one of certain enumerated events in the SERP, the Named Executive Officer would receive an amount based on an allocation for the year of termination. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*" for additional information regarding the enumerated events and allocation determination. The exact amount that any Named Executive Officer would receive could only be determined with certainty upon an actual termination or change in control.

As noted above, the Tholen Employment Letter provides that if Mr. Tholen's employment is involuntarily terminated on or before December 31, 2022, other than for Good Cause (as defined in the Tholen Employment Letter), Mr. Tholen will receive a severance payment in an amount equal to two times Mr. Tholen's then-effective annual base salary plus his target STIP award, and any unpaid installment(s) of the one-time signing bonus described above, which as of December 31, 2019, would equal $3,000,000.

Director Compensation

The sole member of our general partner has the right to set the compensation of the directors of our general partner. Typically, such compensation has been set by the Board of Directors upon recommendation of the Compensation Committee, and with the concurrence of Mr. Craft, who indirectly owns our general partner. Mr. Craft and Mr. Wesley, our only employee directors, received no director compensation for 2019, and all compensation that Mr. Craft received in his capacity as an employee is set forth above within the Summary Compensation Table. The directors of MGP devote 100% of their time as directors of MGP to the business of the ARLP Partnership.

Director Compensation Table for 2019

Name	Fees earned or Paid in Cash ($)	Unit Awards ($) (2)(3)	Option Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)(1)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(1)	All Other Compensation ($)(1)	Total ($)
Robert J. Druten	$ —	$ 187,579	$ —	$ —	$ —	$ —	$ 187,579
John H. Robinson	176,000	—	—	—	—	—	176,000
Wilson M. Torrence	196,000	17,027	—	—	—	—	213,027
Nick Carter	166,000	—	—	—	—	—	166,000

(1) Columns are not applicable.

(2) Amounts represent the grant date fair value of equity awards in 2019 related to deferrals of annual retainer and distributions earned on deferred units (computed in accordance with FASB ASC 718, using the same assumptions as used for financial reporting purposes). Please see *Narrative to Director Compensation Table*, below.

(3) At December 31, 2019, each director had the following number of "phantom" ARLP common units credited to his notional account under MGP's Amended and Restated Deferred Compensation Plan for Directors ("Directors' Deferred Compensation Plan"):

Name	Directors Deferred Compensation Plan (in Units)
Robert J. Druten	10,875
John H. Robinson	—
Wilson M. Torrence	8,926
Nick Carter	—

Narrative to Director Compensation Table

Compensation for our non-employee directors includes an annual cash retainer paid quarterly in advance on a pro rata basis. The annual retainer for calendar year 2019 was $166,000. Mr. Torrence also was entitled to cash compensation of $30,000 for service as Chairman of the Audit Committee, and Mr. Robinson and Mr. Druten also were entitled to additional cash compensation of $10,000 each for service as Chairman of the Compensation Committee and the Conflicts Committee, respectively. Directors have the option to defer all or part of their cash compensation pursuant to the Directors' Deferred Compensation Plan by completing an election form prior to the beginning of each calendar year. Mr. Druten elected to defer all of his cash compensation in 2019 pursuant to the Directors' Deferred Compensation Plan (including the annual retainer described above).

Pursuant to the Directors' Deferred Compensation Plan, a notional account is established for deferred amounts of cash compensation and credited with notional common units of ARLP, described in the plan as "phantom" units. The number of phantom units credited is determined by dividing the amount deferred by the average closing unit price for the ten trading days immediately preceding the deferral date. When quarterly cash distributions are made with respect to ARLP common units, an amount equal to such quarterly distribution is credited to the notional account as additional phantom units. Payment of accounts under the Directors' Deferred Compensation Plan will be made in ARLP common units equal to the number of phantom units then credited to the director's account.

Directors may elect to receive payment of the account resulting from deferrals during a plan year either (a) on the January 1 on or next following their separation from service as a director or (b) on the earlier of a specified January 1 or the January 1 on or next following their separation from service. The payment election must be made prior to each plan year; if no election is made, the account will be paid on the January 1 on or next following the director's separation from service. The Directors' Deferred Compensation Plan is administered by the Compensation Committee, and the Board of Directors may change or terminate the plan at any time; provided, however, that accrued benefits under the plan cannot be impaired.

Upon any recapitalization, reorganization, reclassification, split of common units, distribution or dividend of securities on ARLP common units, our consolidation or merger, or sale of all or substantially all of our assets or other similar transaction that is effected in such a way that holders of common units are entitled to receive (either directly or upon subsequent liquidation) cash, securities or assets with respect to or in exchange for ARLP common units, the Compensation Committee shall, in its sole discretion (and upon the advice of financial advisors as may be retained by the Compensation Committee), immediately adjust the notional balance of phantom units in each director's account under the Directors' Deferred Compensation Plan to equitably credit the fair value of the change in the ARLP common units and/or the distributions (of cash, securities or other assets) received or economic enhancement realized by the holders of the ARLP common units.

The Board of Directors has established a recommendation that each non-employee director should attain within five years following such person's election to the Board of Directors, and thereafter maintain during service on the Board of Directors, ownership of equity of ARLP (including phantom equity ownership under the Directors' Deferred Compensation Plan) with an aggregate value of $220,000.

CEO Pay Ratio Disclosures

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Joseph W. Craft III, our CEO.

For 2019, our last completed fiscal year:

- The median of the annual total compensation of all employees of our company (other than the CEO) was $100,278.
- The annual total compensation of our CEO, as reported in the Summary Compensation Table was $12,963.
- Based on this information, for 2019 the ratio of the annual total compensation of our CEO to the median of the annual total compensation of all employees was reasonably estimated to be 0.1 to 1.

To determine the annual total compensation of our median employee and our CEO, we took the following steps:

- Using the same median employee identified in 2017 and 2018, we combined all of the elements of such employee's compensation for the 2019 year in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in annual total compensation of $100,278, comprised of such employee's W-2 compensation of $95,556 and contributions in the amount of $4,722 that we made on the employee's behalf to our 401(k) plan for the 2019 year.
- With respect to the annual total compensation of our CEO, we used the amount reported in the "Total" column of our 2019 Summary Compensation Table.

Compensation Committee Interlocks and Insider Participation

Mr. Craft, Chairman, President and CEO of our general partner, is also Chairman, President and CEO of AGP. Otherwise, none of our executive officers serves as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of the Board of Directors or Compensation Committee of our general partner.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The following table sets forth certain information as of February 10, 2020, regarding the beneficial ownership of common units held by (a) each director of our general partner, (b) each executive officer of our general partner identified in the Summary Compensation Table included in "Item 11. Executive Compensation" above, (c) all directors and executive officers as a group, and (d) each person known by our general partner to be the beneficial owner of 5% or more of our common units. The address of our general partner and, unless otherwise indicated in the footnotes to the table below, each of the directors, executive officers and 5% unitholders reflected in the table below is 1717 South Boulder Avenue, Suite 400, Tulsa, Oklahoma 74119. Unless otherwise indicated in the footnotes to the table below, the common units reflected as being beneficially owned by our general partner's directors and Named Executive Officers are held directly by such directors and officers. The percentage of common units beneficially owned is based on 127,195,219 common units outstanding as of February 10, 2020.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Directors and Executive Officers		
Joseph W. Craft III (1)	19,502,324	15.3%
Nick Carter	20,000	*
Robert J. Druten	25,628	*
John H. Robinson	18,462	*
Wilson M. Torrence	40,396	*
Charles R. Wesley III (2)	2,386,852	1.9%
Brian L. Cantrell	189,332	*
R. Eberley Davis	140,146	*
Robert J. Fouch	59,065	*
Robert G. Sachse	203,736	*
Kirk D. Tholen	—	*
Thomas M. Wynne (3)	1,146,709	*
Timothy Whelan	65,601	*
All directors and executive officers as a group (13 persons)	23,798,251	18.7%
5% Common Unit Holder		
Kathleen S. Craft (4)	16,237,609	12.8%

* Less than one percent.

(1) The common units attributable to Mr. Craft consist of (i) 19,305,581 common units held directly by him, (ii) 168,602 common units attributable to Mr. Craft's spouse and (iii) 28,141 common units held by SGP (indirectly jointly owned by Mr. Craft and Kathleen S. Craft).

(2) The common units attributable to Mr. Wesley consist of (i) 1,035,728 common units held directly by him and (ii) 1,351,124 common units held through trusts and other entities controlled by him.

(3) The common units attributable to Mr. Wynne consist of (i) 795,673 common units held directly by him and (ii) 351,036 common units held through a trust and another entity controlled by him.

(4) The common units attributable to Kathleen S. Craft consist of (i) 16,209,468 common units held directly by her and (ii) 28,141 common units held by SGP (indirectly jointly owned by Mr. Craft and Kathleen S. Craft).

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, 2019	Weighted-average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans as of December 31, 2019
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	1,603,378	N/A	1,807,045
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	611,564	N/A	N/A
Directors' Deferred Compensation	19,801	N/A	N/A

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

In addition to the related-party transactions discussed in "Item 8. Financial Statements and Supplementary Data—Note 10 — Partners' Capital and Note 20 — Related-Party Transactions," ARLP has the following additional related-party transactions:

Certain Relationships

We are managed by MGP, which holds a non-economic general partner interest in us. Prior to the Simplification Transactions discussed in "Item 8. Financial Statements and Supplementary Data—Note 1 — Organization and Presentation – Partnership Simplification," AHGP directly and indirectly through its wholly owned subsidiary, MGP II, LLC ("MGP II") owned approximately 66.7% of our total outstanding common units, and MGP was a wholly owned subsidiary of MGP II. As a result of the Simplification Transactions, AHGP and MGP II became wholly owned subsidiaries of ARLP and MGP remained our sole general partner and became a wholly owned subsidiary of AGP, which is indirectly wholly owned by Mr. Craft. MGP's ability, as general partner, to control us effectively gives MGP the ability to veto our actions and to control our management.

Prior to the Simplification Transactions, certain of our officers and directors were also officers and/or directors of AHGP's general partner, AGP, including Mr. Craft, the Chairman, President and CEO of our general partner, Mr. Torrence, a Director, member of the Compensation Committee and Chairman of the Audit Committee of the MGP Board of Directors, Mr. Cantrell, the Senior Vice President and Chief Financial Officer of our general partner, Mr. Davis, the Senior Vice President, General Counsel and Secretary of our general partner, and Mr. Fouch, Vice President, Controller and Chief Accounting Officer of our general partner. Following the Simplification Transactions, Messrs. Craft, Cantrell, Davis and Fouch continue to be officers of AGP, which is no longer the general partner of AHGP as a result of the Simplification Transactions.

Related-Party Transactions

The Board of Directors and its Conflicts Committee review our related-party transactions that involve a potential conflict of interest between MGP or any of its affiliates and ARLP or its subsidiaries or any other partner of ARLP to determine that such transactions reflect market-clearing terms and customary conditions. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to us and our limited partners.

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into an Administrative Services Agreement with our general partner, our Intermediate Partnership, AGP, and ARH II. Under the Administrative Services Agreement, certain employees, including some executive officers, provided administrative services for AGP and ARH II and their respective affiliates.

Our partnership agreement provides that MGP and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, director fees and expenses, management's salaries and related benefits (including incentive compensation), and accounting, budgeting, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers' compensation management, legal and information technology services. MGP may determine in its sole discretion the expenses that are allocable to us. Total costs billed to us by our general partner and its affiliates were approximately $0.7 million for the year ended December 31, 2019. The executive officers of our general partner are employees of and paid by Alliance Coal, and the reimbursement we pay to our general partner pursuant to the partnership agreement does not include any compensation expenses associated with them.

JC Land

Our subsidiary, ASI, has a time-sharing agreement with Mr. Craft and Mr. Craft's affiliate, JC Land, LLC ("JC Land"), concerning their use of aircraft owned by Alliance Service, Inc. ("ASI") for purposes other than our business. In accordance with the provisions of that agreement, Mr. Craft and JC Land paid ASI $0.1 million for the year ended December 31, 2019 for use of the aircraft. In addition, Alliance Coal has a time-sharing agreement with JC Land concerning Alliance Coal's use of an airplane owned by JC Land. In accordance with the provisions of that agreement, Alliance Coal paid JC Land $0.2 million for the year ended December 31, 2019 for use of the aircraft.

Effective August 1, 2013, Alliance Coal entered into an expense reimbursement agreement with JC Land regarding pilots hired by Alliance Coal to operate aircraft owned by ASI and JC Land. In accordance with the expense reimbursement agreement, JC Land reimburses Alliance Coal for a portion of the compensation expense for its pilots. JC Land paid us $0.4 million in 2019 pursuant to this agreement. Separately, we billed JC Land $0.6 million during 2019 for fuel, maintenance, pilot travel, etc. paid by us on their behalf.

SGP Land/Craft Foundations

In 2001, SGP Land, LLC as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining was required to pay an annual minimum royalty of $0.3 million until $6.0 million of cumulative annual minimum and/or earned royalty payments had been paid. The cumulative annual minimum lease requirement of $6.0 million was met in 2015. MC Mining paid earned royalties of $0.3 million, $0.1 million and $0.6 million in 2019, 2018 and 2017 respectively. As of January 1, 2019 the property subject to this lease is owned by the Joseph W. Craft III Foundation and the Kathleen S. Craft Foundation, an undivided one-half interest each (the "Craft Foundations").

SGP/Craft Foundations

Tunnel Ridge has a surface land lease with SGP with an annual payment of $0.2 million, payable in January of each year. As of January 1, 2019 the property subject to this lease is owned by the Craft Foundations, an undivided one-half interest each.

Omnibus Agreement

We are party to an omnibus agreement with ARH, MGP and AGP, which govern potential competition among us and the other parties to this agreement. Pursuant to the terms of the omnibus agreement, ARH and AGP agreed, and caused their controlled affiliates to agree, for so long as management controls MGP, not to engage in the business of mining, marketing or transporting coal in the United States, unless it first offers us the opportunity to engage in a potential activity or acquire a potential business, and the Board of Directors, with the concurrence of its Conflicts Committee, elects to cause us not to pursue such opportunity or acquisition. In addition, ARH has the ability to purchase businesses, the majority value of which is not mining, marketing or transporting coal, provided ARH offers us the opportunity to purchase the coal assets following their acquisition. The restriction does not apply to the assets retained and business conducted by ARH at the closing of our initial public offering. Except as provided above, ARH and AGP and their controlled affiliates are prohibited from engaging in activities wherein they compete directly with us. In addition to its non-competition provisions, the agreement also provides for indemnification of us against liabilities associated with certain assets and businesses of ARH that were disposed of or liquidated prior to consummating our initial public offering.

Director Independence

As a publicly traded limited partnership listed on the NASDAQ Global Select Market, we are required to maintain a sufficient number of independent directors on the board of our general partner to satisfy the audit committee requirement set forth in NASDAQ Rule 4350(d)(2). Rule 4350(d)(2) requires us to maintain an audit committee of at least three members, each of whom must, among other requirements, be independent as defined under NASDAQ Rule 4200(a)(15) and meet the criteria for independence set forth in Rule 10A-3(b)(1) under the Exchange Act (subject to the exemptions provided in Rule 10A-3(c)).

All members and former members of the Audit Committee—Messrs. Torrence, Carter, Druten and Robinson—and all members and former members of the Compensation Committee—Messrs. Robinson, Carter, Druten and Torrence—are independent directors as defined under applicable NASDAQ and Exchange Act rules. Please see "Item 10. Directors, Executive Officers and Corporate Governance of the General Partner—Audit Committee" and "Item 11. Executive Compensation—Compensation Discussion and Analysis."

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The firm of Ernst & Young LLP is our independent registered public accounting firm. The following table sets forth fees paid to Ernst & Young LLP during the years ended December 31, 2019 and 2018:

	2019	2018
	(in thousands)	
Audit Fees (1)	$ 1,175	$ 1,093
Audit-related fees (2)	—	—
Tax fees (3)	398	460
All other fees	—	—
Total	$ 1,573	$ 1,553

(1) Audit fees consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with GAAP.

(2) Audit-related fees include fees related to acquisition due diligence and accounting consultations.

(3) Tax fees consist primarily of services rendered for tax compliance, tax advice, and tax planning.

The charter of the Audit Committee provides that the committee is responsible for the pre-approval of all auditing services and permitted non-audit services to be performed for us by our independent registered public accounting firm, subject to the requirements of applicable law. In accordance with such charter, the Audit Committee may delegate the authority to grant such pre-approvals to the Audit Committee chairman or a sub-committee of the Audit Committee, which pre-approvals are then reviewed by the full Audit Committee at its next regular meeting. Typically, however, the Audit Committee itself reviews the matters to be approved. The Audit Committee periodically monitors the services rendered by and actual fees paid to the independent registered public accounting firm to ensure that such services are within the parameters approved by the Audit Committee.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements and Supplementary Data.

(a)(2) Financial Statement Schedule.

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

(a)(3) and (c) The exhibits listed below are filed as part of this annual report.

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
2.1	Simplification Agreement, dated as of February 22, 2018, by and among Alliance Holdings GP, L.P., Alliance GP, LLC, Wildcat GP Merger Sub, LLC, MGP II, LLC, ARM GP Holdings, Inc., New AHGP GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC and Alliance Resource GP, LLC.	8-K	000-26823 18634680	2.1	02/23/2018	
3.1	Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 17990766	3.2	07/28/2017	
3.2	Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P.	10-K	000-26823 583595	3.2	03/29/2000	
3.3	Amended and Restated Certificate of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 17990766	3.6	07/28/2017	
3.4	Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P.	S-1/A	333-78845 99669102	3.8	07/23/1999	
3.5	Certificate of Formation of Alliance Resource Management GP, LLC	S-1/A	333-78845 99669102	3.7	07/23/1999	
3.6	Amendment No. 1 to the Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	10-K	000-26823 18634680	3.9	02/23/2018	
3.7	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., dated as of May 31, 2018.	8-K	000-26823 1883834	3.3	06/06/2018	
3.8	Amendment No. 3 to Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., dated as of June 1, 2018.	8-K	000-26823 1883834	3.4	06/06/2018	
3.9	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P., dated as of May 31, 2018.	8-K	000-26823 1883834	3.5	06/06/2018	
3.10	Third Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC, dated as of May 31, 2018.	8-K	000-26823 1883834	3.7	06/06/2018	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
4.1	Form of Common Unit Certificate (Included as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., included in this Exhibit Index as Exhibit 3.1).	8-K	000-26823 08763867	3.1	04/18/2008	
4.2	Indenture, dated as of April 24, 2017, by and among Alliance Resource Operating Partners, L.P. and Alliance Resource Finance Corporation, as issuers, Alliance Resource Partners, L.P., as parent, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee.	8-K	000-26823 17798539	4.1	04/24/2017	
4.3	Form of 7.500% Senior Note due 2025 (included in Exhibit 4.2).	8-K	000-26823 17778550	4.1	04/24/2017	
4.4	Description of the Registrant’s Securities registered under Section 12 of the Securities Exchange Act of 1934.					☑
10.1	Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein.	10-K	000-26823 583595	10.2	03/29/2000	
10.2	Amendment and Restatement of Letter of Credit Facility Agreement dated October 2, 2010.	10-Q	000-26823 11823116	10.1	05/09/2011	
10.3	Letter of Credit Facility Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association.	10-Q	000-26823 1782487	10.25	11/13/2001	
10.4	First Amendment to the Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association.	10-Q	000-26823 02827517	10.32	11/14/2002	
10.5	Promissory Note Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, N.A.	10-Q	000-26823 1782487	10.26	11/13/2001	
10.6	Guarantee Agreement, dated as of October 2, 2001, between Alliance Resource GP, LLC and Bank of the Lakes, N.A.	10-Q	000-26823 1782487	10.27	11/13/2001	
10.7	Contribution and Assumption Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. and the other parties named therein	10-K	000-26823 583595	10.3	03/29/2000	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.8	Omnibus Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC and Alliance Resource Partners, L.P.	10-K	000-26823 583595	10.4	03/29/2000	
10.9(1)	Amended and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.17	03/15/2004	
10.10(1)	First Amendment to the Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.18	03/15/2004	
10.11(1)	Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 583595	10.12	03/29/2000	
10.12(1)	Alliance Coal, LLC Supplemental Executive Retirement Plan	S-8	333-85258 02595143	99.2	04/01/2002	
10.13(1)	Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	S-8	333-85258 02595143	99.3	04/01/2002	
10.14	Guaranty by Alliance Resource Partners, L.P. dated March 16, 2012	10-Q	000-26823 12825281	10.3	05/09/2012	
10.15(2)	Base Contract for Purchase and Sale of Coal, dated March 16, 2012, between Seminole Electric Cooperative, Inc. and Alliance Coal, LLC	10-Q	000-26823 12825281	10.1	05/09/2012	
10.16(2)	Contract of Confirmation, effective March 16, 2012, between Seminole Electric Cooperative, Inc., Alliance Coal, LLC and Alliance Resource Partners, L.P.	10-Q/A	000-26823 12947715	10.2	07/05/2012	
10.17	Amended and Restated Charter for the Audit Committee of the Board of Directors dated February 23, 2009	10-K	000-26823 09647063	10.35	03/02/2009	
10.18	Second Amendment to the Omnibus Agreement dated May 15, 2006 by and among Alliance Resource Partners, L.P., Alliance Resource GP, LLC, Alliance Resource Management GP, LLC, Alliance Resource Holdings, Inc., Alliance Resource Holdings II, Inc., AMH-II, LLC, Alliance Holdings GP, L.P., Alliance GP, LLC and Alliance Management Holdings, LLC	10-Q	000-26823 061017824	10.1	08/09/2006	
10.19	Administrative Services Agreement dated May 15, 2006 among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Holdings GP, L.P. and Alliance GP, LLC	10-Q	000-26823 061017824	10.2	08/09/2006	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.20[1]	First Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 07660999	10.50	03/01/2007	
10.21[1]	Second Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 08654096	10.50	02/29/2008	
10.22[1]	First Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 07660999	10.52	03/01/2007	
10.23[1]	Second Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 08654096	10.53	02/29/2008	
10.24	Note Purchase Agreement, 6.28% Senior Notes Due June 26, 2015, and 6.72% Senior Notes due June 26, 2018, dated as of June 26, 2008, by and among Alliance Resource Operating Partners, L.P. and various investors	8-K	000-26823 08928968	10.1	07/01/2008	
10.25	First Amendment, dated as of June 26, 2008, to the Note Purchase Agreement, dated August 16, 1999, 8.31% Senior Notes due August 20, 2014, by and among Alliance Resource Operating Partners, L.P. (as successor to Alliance Resource GP, LLC) and various investors	8-K	000-26823 08928968	10.2	07/01/2008	
10.26[1]	Third Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 09647063	10.52	03/02/2009	
10.27[1]	Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan dated as of January 1, 2011	10-K	000-26823 11645603	10.40	02/28/2011	
10.28[1]	Amended and Restated Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors dated as of January 1, 2011	10-K	000-26823 11645603	10.42	02/28/2011	
10.29	Amendment No. 2 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association, dated April 13, 2009	10-Q	000-26823 09811514	10.1	05/08/2009	
10.30[2]	Agreement for the Supply of Coal, dated August 20, 2009 between Tennessee Valley Authority and Alliance Coal, LLC	10-Q	000-26823 091164883	10.2	11/06/2009	
10.31	Amended and Restated Charter for the Compensation Committee of the Board of Directors dated February 23, 2010.	10-K	000-26823 10638795	10.49	02/26/2010	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.32	Amended and Restated Administrative Services Agreement effective January 1, 2010, among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Resource Operating Partners, L.P., Alliance Holdings GP, L.P. and Alliance GP, LLC.	10-Q	000-26823 101000555	10.1	08/09/2010	
10.33	Uncommitted Line of Credit and Reimbursement Agreement dated April 9, 2010 between Alliance Resource Partners, L.P. and Fifth Third Bank.	10-Q	000-26823 101000555	10.2	08/09/2010	
10.34	Purchase and Sale Agreement, dated as of December 5, 2014, among Alliance Resource Operating Partners, L.P., as buyer and Alliance Coal, LLC, Gibson County Coal, LLC, Hopkins County Coal, LLC, Mettiki Coal (WV), LLC, Mt. Vernon Transfer Terminal, LLC, River View Coal, LLC, Sebree Mining, LLC, Tunnel Ridge, LLC and White County Coal, LLC, as originators	8-K	000-26823 141277053	10.1	12/10/2014	
10.35	Sale and Contribution Agreement, dated as of December 5, 2014, among Alliance Resource Operating Partners, L.P., as seller and AROP Funding, LLC, as buyer	8-K	000-26823 141277053	10.2	12/10/2014	
10.36	Receivables Financing Agreement, dated as of December 5, 2014, among Borrower, PNC Bank, National Association, as administrative agent as well as the letter of credit bank, the persons from time to time party thereto as lenders, the persons from time to time party thereto as letter of credit participants, and Alliance Coal, LLC, as initial servicer	8-K	000-26823 141277053	10.3	12/10/2014	
10.37	Performance Guaranty, dated as of December 5, 2014, by AROP in favor of PNC Bank, National Association, as administrative agent	8-K	000-26823 141277053	10.4	12/10/2014	
10.38	Master Lease Agreement, dated as of October 29, 2015, between Alliance Resource Operating Partners, L.P., Hamilton County Coal, LLC and White Oak Resources LLC, as lessees, and PNC Equipment Finance, LLC and the other lessors named therein.	8-K	000-26823 151198024	10.1	11/04/2015	
10.39(1)	The Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan as amended by the Third Amendment and Fourth Amendment	10-K	000-26823 161460619	10.46	02/26/2016	
10.40	First Amendment to the Receivables Financing Agreement, dated as of December 4, 2015	10-Q	000-26823 161634229	10.1	05/10/2016	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.41	Second Amendment to the Receivables Financing Agreement, dated as of February 24, 2016	10-Q	000-26823 161634229	10.2	05/10/2016	
10.42	Joinder Agreement, dated as of February 24, 2016, among Warrior Coal, LLC, Webster County Coal, LLC, White Oak Resources LLC and Hamilton County Coal, LLC, dated as of February 24, 2016	10-Q	000-26823 161634229	10.3	05/10/2016	
10.43	Fourth Amended and Restated Credit Agreement, dated as of January 27, 2017, by and among Alliance Resource Operating Partners, L.P., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto.	8-K	000-26823 17567534	10.1	02/02/2017	
10.44	First Amendment to Note Purchase Agreement, dated as of January 27, 2017, by and among Alliance Resource Operating Partners, L.P. and the subsidiary guarantors and various investors named therein.	8-K	000-26823 17567534	10.2	02/02/2017	
10.45	Third Amendment to the Receivables Financing Agreement, dated as of December 2, 2016	10-K	000-26823 17636362	10.45	02/24/2017	
10.46	Amendment No. 1 dated April 3, 2017 to the Fourth Amended and Restated Credit Agreement, dated as of January 27, 2017, by and among Alliance Resource Operating Partners, L.P., as borrower, the initial lenders, initial issuing banks and swingline bank named therein, JPMorgan Chase Bank, N.A., as administrative agent, JPMorgan Chase Bank, N.A., Wells Fargo Securities, LLC and Citigroup Global Markets Inc. as joint lead arrangers, JPMorgan Chase Bank, N.A., Wells Fargo Securities, LLC, Citigroup Global Markets Inc., and BOKF, NA DBA Bank of Oklahoma as joint bookrunners, Wells Fargo Bank, National Association, Citibank, N.A., and BOKF, NA DBA Bank of Oklahoma as syndication agents, and the other institutions named therein as documentation agents.	8-K	000-26823 17750742	10.1	04/07/2017	
10.47	Fourth Amendment to the Receivables Financing Agreement, dated as of November 27, 2017	10-K	000-26823 18634680	10.47	02/23/2018	
10.48	Fifth Amendment to the Receivables Financing Agreement, dated as of January 17, 2018	10-K	000-26823 18634680	10.48	02/23/2018	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
10.49	Contribution Agreement, dated as of July 28, 2017, by and among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, ARM GP Holdings, Inc., MGP II, LLC and Alliance Holdings GP, L.P.	8-K	000-26823 17990766	10.1	07/28/2017	
10.50	First Amendment to Contribution Agreement, dated as of May 31, 2018, by and among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, ARM GP Holdings, Inc., MGP II, LLC and Alliance Holdings GP, L.P.	8-K	000-26823 18883834	10.1	06/06/2018	
10.51	Sixth Amendment to the Receivables Financing Agreement, dated as of June 19, 2018	10-Q	000-26823 18994075	10.2	08/06/2018	
10.52	Seventh Amendment to the Receivables Financing Agreement, dated as of January 16, 2019	10-K	000-26823 19624803	10.52	02/22/2019	
10.53	Subscription Agreement for Partnership Interest - General Partner Interest dated December 14, 2018 by and among Alliance Resource Partners, L.P., AllDale Minerals, LP and AllDale Mineral Management, LLC.	10-K	000-26823 19624803	10.53	02/22/2019	
10.54	Subscription Agreement for Partnership Interest - Limited Partner Interest dated December 14, 2018 by and among Alliance Resource Partners, L.P., AllDale Minerals, LP and AllDale Mineral Management, LLC.	10-K	000-26823 19624803	10.54	02/22/2019	
10.55	Subscription Agreement for Partnership Interest - General Partner Interest dated December 14, 2018 by and among Alliance Resource Partners, L.P., AllDale Minerals II, LP and AllDale Mineral Management II, LLC.	10-K	000-26823 19624803	10.55	02/22/2019	
10.56	Subscription Agreement for Partnership Interest - Limited Partner Interest dated December 14, 2018 by and among Alliance Resource Partners, L.P., AllDale Minerals II, LP and AllDale Mineral Management II, LLC.	10-K	000-26823 19624803	10.56	02/22/2019	
10.57	AllDale Minerals, LP Joinder Agreements dated January 3, 2019 by and among Alliance Royalty, LLC, AllRoy GP, LLC and AllDale Minerals, LP.	10-K	000-26823 19624803	10.57	02/22/2019	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	 SEC File No. and Film No.	 Exhibit	 Filing Date	Filed Herewith*
10.58	AllDale Minerals II, LP Joinder Agreements dated January 3, 2019 by and among Alliance Royalty, LLC, AllRoy GP, LLC and AllDale Minerals II, LP.	10-K	000-26823 19624803	10.58	02/22/2019	
10.59	Purchase and Sale Agreement by and between Wing Resources LLC, and Wing Resources II LLC, as sellers, and Alliance Resource Partners, L.P., as buyer, dated as of June 21, 2019.	10-Q	000-26823 19997858	10.1	08/05/2019	
10.60	Eighth Amendment to the Receivables Financing Agreement, dated as of October 22, 2019.	10-Q	000-26823 191192460	10.2	11/05/2019	
10.61	Employment letter to Kirk Tholen, dated October 21, 2019					☑
14.1	Code of Ethics for Principal Executive Officer and Senior Financial Officers	10-K	000-26823 13656028	14.1	03/01/2013	
21.1	List of Subsidiaries.					☑
23.1	Consent of Ernst & Young LLP.					☑
23.2	Consent of Netherland, Sewell & Associates, Inc.					☑
31.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 20, 2020, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					☑
31.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 20, 2020, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					☑
32.1	Certification of Joseph W. Craft III, President and Chief Executive Officer and Chairman of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 20, 2020, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					☑
32.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 20, 2020, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					☑

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
95.1	Federal Mine Safety and Health Act Information					☑
99.1	Report of Netherland, Sewell & Associates, Inc., dated February 7, 2020					☑
101	Interactive Data File (Form 10-K for the year ended December 31, 2019 filed in Inline XBRL).					☑
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).					☑

* Filed herewith (or furnished, in the case of Exhibits 32.1 and 32.2).

(1) Denotes management contract or compensatory plan or arrangement.
(2) Portions of this exhibit have been omitted pursuant to a request for confidential treatment under Rule 24b-2 of the Exchange Act, as amended, and the omitted material has been separately filed with the SEC.

Signatures

Pursuant to the requirements 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, in Tulsa, Oklahoma, on February 20, 2020.

ALLIANCE RESOURCE PARTNERS, L.P.

By: Alliance Resource Management GP, LLC
its general partner

/s/ Joseph W. Craft III
Joseph W. Craft III
President, Chief Executive Officer and Chairman

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/ Joseph W. Craft III Joseph W. Craft III	President, Chief Executive Officer, and Chairman (Principal Executive Officer)	February 20, 2020
/s/ Brian L. Cantrell Brian L. Cantrell	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 20, 2020
/s/ Robert J. Fouch Robert J. Fouch	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 20, 2020
/s/ Nick Carter Nick Carter	Director	February 20, 2020
/s/ Robert J. Druten Robert J. Druten	Director	February 20, 2020
/s/ John H. Robinson John H. Robinson	Director	February 20, 2020
/s/ Wilson M. Torrence Wilson M. Torrence	Director	February 20, 2020
/s/ Charles R. Wesley Charles R. Wesley	Executive Vice President and Director	February 20, 2020

ALLIANCE RESOURCE PARTNERS, L.P.

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