2021
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, 2021

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	73-1564280
(State or Other Jurisdiction of Incorporation or Organization)	(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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 726(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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 $745,685,497 as of June 30, 2021, 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 25, 2022, 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 expectations, we classify coal with a sulfur content of greater than 3%
Indicated mineral resource	That part of a mineral resource for which quantity and grade or quality are estimated on the basis of adequate geological evidence and sampling. The level of geological certainty associated with an indicated mineral resource is sufficient to allow a qualified person to apply modifying factors in sufficient detail to support mine planning and evaluation of the economic viability of the deposit. Because an indicated mineral resource has a lower level of confidence than the level of confidence of a measured mineral resource, an indicated mineral resource may only be converted to a probable mineral reserve.
Inferred mineral resource	That part of a mineral resource for which quantity and grade or quality are estimated on the basis of limited geological evidence and sampling. The level of geological uncertainty associated with an inferred mineral resource is too high to apply relevant technical and economic factors likely to influence the prospects of economic extraction in a manner useful for evaluation of economic viability. Because an inferred mineral resource has the lowest level of geological confidence of all mineral resources, which prevents the application of the modifying factors in a manner useful for evaluation of economic viability, an inferred mineral resource may not be considered when assessing the economic viability of a mining project, and may not be converted to a mineral reserve.
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 expectations, we classify coal with a sulfur content of less than 1.5%
Measured mineral resource	That part of a mineral resource for which quantity and grade or quality are estimated on the basis of conclusive geological evidence and sampling. The level of geological certainty associated with a measured mineral resource is sufficient to allow a qualified person to apply modifying factors, as defined in this section, in sufficient detail to support detailed mine planning and final evaluation of the economic viability of the deposit. Because a measured mineral resource has a higher level of confidence than the level of confidence of either an indicated mineral resource or an inferred mineral resource, a measured mineral resource may be converted to a proven mineral reserve or to a probable mineral reserve.
Medium-sulfur coal	Based 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
Mineral reserve	An estimate of tonnage and grade or quality of indicated and measured mineral resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, it is the economically mineable part of a measured or indicated mineral resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted.
Mineral resource	A concentration or occurrence of material of economic interest in or on the Earth's crust in such form, grade or quality, and quantity that there are reasonable prospects for economic extraction. A mineral resource is a reasonable estimate of mineralization, taking into account relevant factors such as cut-off grade, likely mining dimensions, location or continuity that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. It is not merely an inventory of all mineralization drilled or sampled.
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 mineral reserve	The economically mineable part of an indicated and, in some cases, a measured mineral resource.
Proven mineral reserve	The economically mineable part of a measured mineral resource and can only result from conversion of a measured mineral resource.
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
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
Gross Acres	The total acres in a specified tract in which an owner has a real property interest. For example, an owner who has a 25 percent interest in 100 acres has an ownership interest in 100 gross acres.
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
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
MMcf	Million cubic feet of natural gas
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 the surface in field facilities or 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.
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
PUDs	Proved undeveloped reserves
Reserves	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	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 from being classified as proved.

FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K, and certain oral statements made from time to time by our representatives, 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," "could," "estimate," "expect," "forecast," "foresee," "may," "outlook," "plan," "project," "potential," "should," "will," "would," 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 forward-looking statements are based on our current expectations and beliefs concerning future developments and 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 could 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:

- the severity, magnitude, and duration of the COVID-19 pandemic and the emergence of new virus variants, including impacts of the pandemic and of businesses' and governments' responses to the pandemic, including actions to mitigate its impact and the development of treatments and vaccines, on our operations and personnel, and on demand for coal, oil, and natural gas, the financial condition of our customers and suppliers, available liquidity and capital sources and broader economic disruptions;
- changes in macroeconomic and market conditions and market volatility arising from the COVID-19 pandemic or otherwise, including inflation, changes in coal, oil, natural gas, and natural gas liquids prices, and the impact of such changes and volatility on our financial position;
- 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;
- changes in global economic and geo-political 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;
- actions of the major oil-producing countries with respect to oil production volumes and prices could have direct and indirect impacts over the near and long term on oil & gas exploration and production operations at the properties in which we hold mineral interests;
- changes in competition in domestic and international coal markets and our ability to respond to such changes;
- potential shut-ins of production by operators of the properties in which we hold mineral interests due to low oil, natural gas, and natural gas liquid prices or the lack of downstream demand or storage capacity;
- 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;
- the effects of and changes in trade, monetary and fiscal policies and laws, including the interest rate policies of the Federal Reserve Board;
- the effects of and changes in taxes or tariffs and other trade measures adopted by the United States and foreign governments;
- 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;
- investors' and other stakeholders' increasing attention to environmental, social, and governance ("ESG") matters;
- 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, including due to inflationary pressures;

- changes in our ability to recruit, hire and maintain labor, including, as a result of, the potential impact of government-imposed vaccine mandates;
- 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, 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 mineral reserves and resources;
- 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 our underlying assumptions prove incorrect, our actual results could differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind our risk factors and legal proceedings. Known material factors that could cause our actual results to differ from those in the forward-looking statements are described in "Item 1A. Risk Factors" and "Item 3. Legal Proceedings." We disclaim any obligation to update or revise any forward-looking statements or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments unless required by law.

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 U.S. 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", "Partnership" 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 general partner.
- References to "Mr. Craft" mean Joseph W. Craft III, the Chairman, President and Chief Executive Officer of MGP.
- 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 our coal mining operations.
- References to "Alliance Minerals" mean Alliance Minerals, LLC, the holding company for our oil and gas minerals interests.
- References to "Alliance Resource Properties" mean Alliance Resource Properties, LLC, the land holding company for certain of our coal mineral interests, including the subsidiaries of Alliance Resource Properties, LLC.

PART I

ITEM 1. BUSINESS

General

Introduction

We are a diversified natural resource company that generates operating income from the production and marketing of coal and royalty income from coal 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 coal and oil & gas mineral ownership. We believe that our diverse and rich resource base will allow us to continue to create long-term value for unitholders.

We are currently the second-largest coal producer in the eastern United States with seven operating underground mining complexes in Illinois, Indiana, Kentucky, Maryland, Pennsylvania, and West Virginia as well as a coal-loading terminal in Indiana on the Ohio River. We manage and report our coal operations 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 1.5 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.

We currently have approximately 547.1 million tons of proven and probable coal mineral reserves and 1.17 billion tons of measured, indicated and inferred coal mineral resources in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. All of our measured, indicated and inferred coal mineral resources and 422.9 million tons of our coal mineral reserves are owned or leased by Alliance Resource Properties, which are (a) leased or subleased to internal mining complexes or (b) near other internal and external coal mining operations but not yet leased. We market our coal mineral reserves and resources to the coal mining operations that are able to access them and generate royalty income from the leasing and development of those coal mineral reserves and resources.

In addition, we develop and market industrial, mining and 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.

AllDale I & II Acquisition

On January 3, 2019 (the "Acquisition Date"), we 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 (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 provided us with diversified exposure to industry-leading operators.

Wing Acquisition

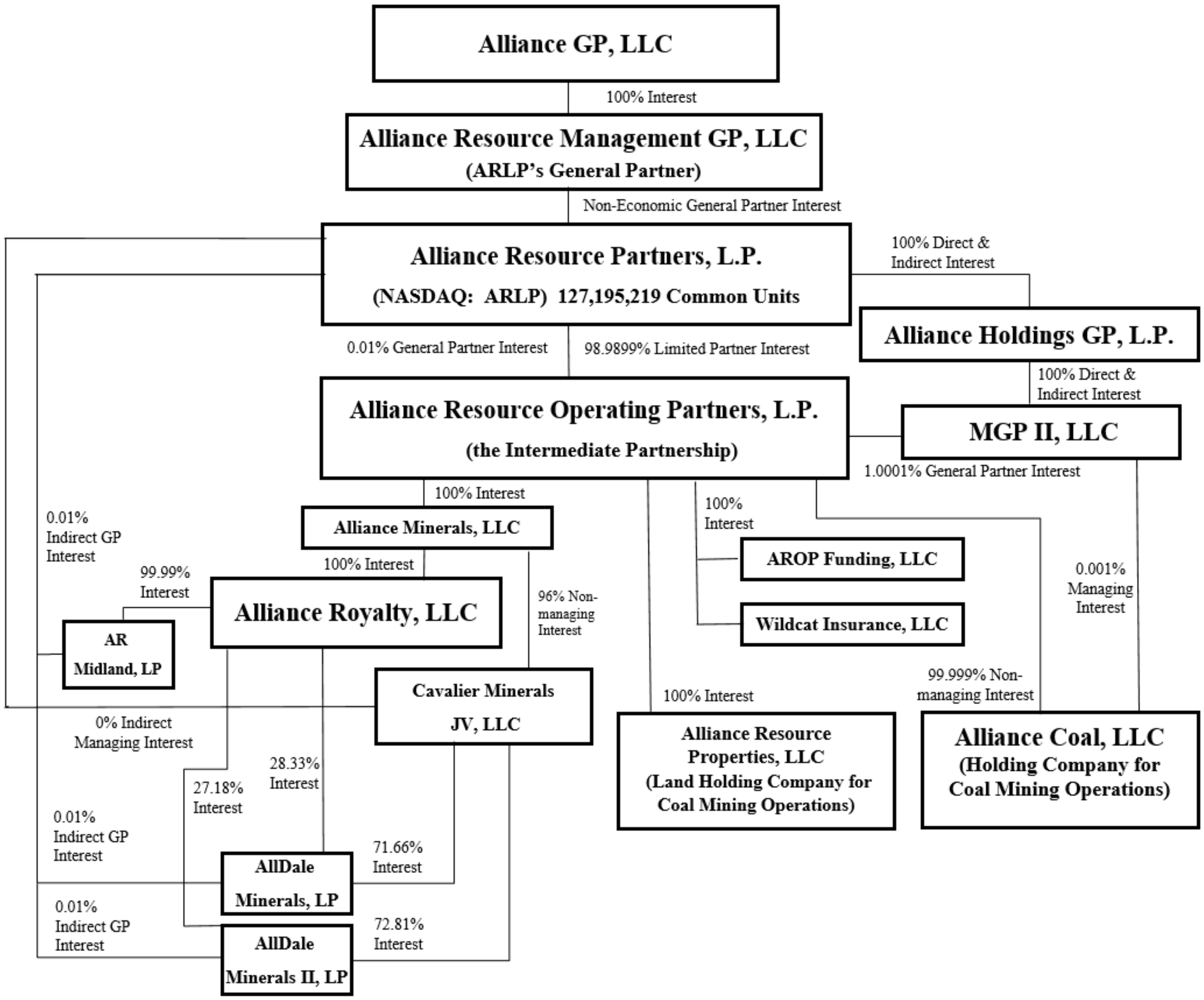
On August 2, 2019, our subsidiary AR Midland, LP ("AR Midland") acquired from Wing Resources LLC and Wing Resources II LLC (collectively, "Wing") approximately 9,000 oil & gas net royalty acres in the Midland Basin for $144.9 million (the "Wing Acquisition"). The Wing Acquisition enhanced our ownership position in the Permian Basin and expanded our exposure to industry-leading operators.

Boulders Acquisition

On October 13, 2021, AR Midland acquired approximately 1,480 oil & gas net royalty acres in the Delaware Basin from Boulders Royalty Corp. ("Boulders") for a purchase price of $31.0 million (the "Boulders Acquisition"). The Boulders Acquisition also enhanced our ownership position in the Permian Basin.

These acquisitions furthered our business strategy to grow our Oil & Gas Royalties segment through accretive acquisitions. See "Item 8. Financial Statements and Supplementary Data—Note 3 – Acquisitions" for more information. We now hold approximately 57,000 net royalty acres in premier oil & gas resource plays.

The following diagram depicts our simplified organization and ownership as of December 31, 2021:



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

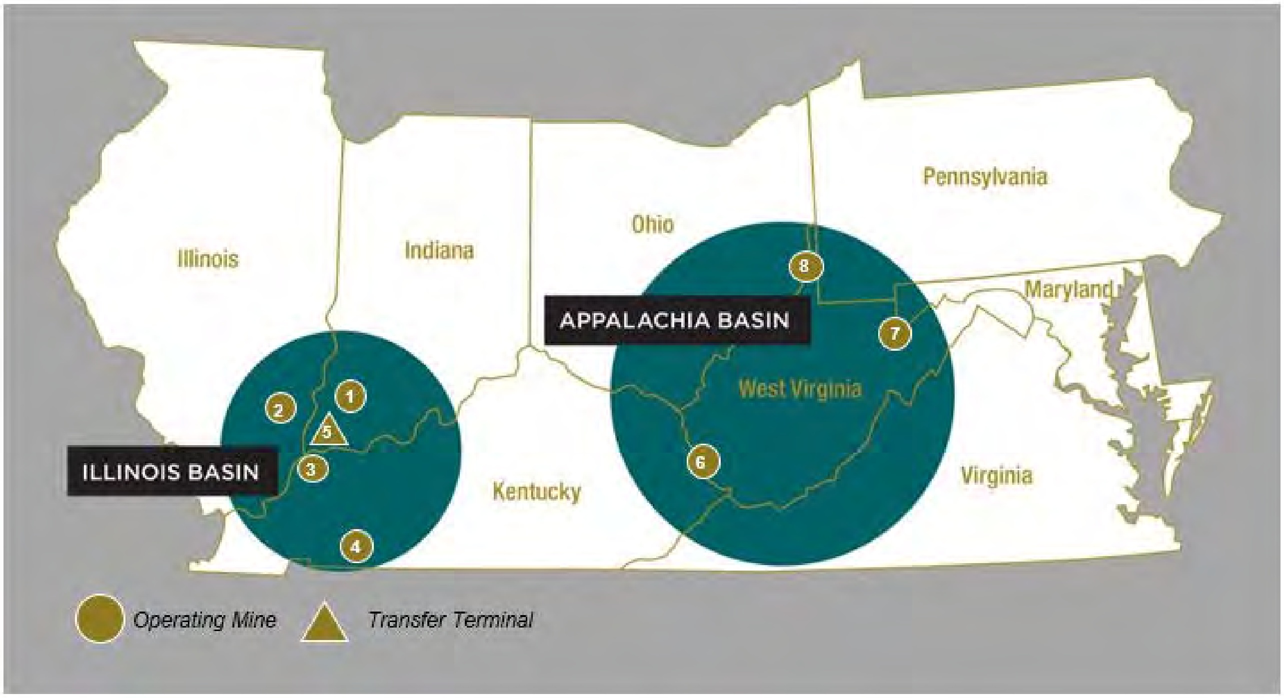
Coal is used primarily for the generation of electric power and production of steel but is also used for chemical, food, and cement processing. We produce bituminous coal from our underground mines that is sold to customers principally for electric power generation (thermal) and the production of steel (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, 2021, our mining operations had access to approximately 547.1 million tons of proven and probable coal mineral reserves and 1.17 billion tons of measured, indicated and inferred coal mineral resources in Illinois, Indiana, Kentucky, Maryland, Pennsylvania, and West Virginia. All of our measured, indicated and inferred coal mineral resources and 422.9 million tons of our coal mineral reserves are owned or leased by Alliance Resource Properties and are currently leased or subleased or held for lease or sublease to our mining operations or others. 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 2021, we sold 32.3 million tons of coal and produced 32.2 million tons. Of the 32.3 million tons sold, approximately two-thirds was leased from Alliance Resource Properties. The coal we sold in 2021 was approximately 14.2% low-sulfur coal, 50.3% medium-sulfur coal, and 35.5% high-sulfur coal. In 2021, approximately 81.6% of our tons sold were purchased by domestic electric utilities and 12.5% were sold into the international markets through brokered transactions. The balance of our tons sold was to third-party resellers and industrial consumers. For tons sold to domestic electric utilities, 99.9% were sold to utility plants with installed pollution control devices. The Btu content of our coal ranges from 11,450 to 13,200.

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

	Year Ended December 31,		
Coal Regions	**2021**	**2020**	**2019**
		(tons in millions)	
Illinois Basin	22.2	17.9	29.5
Appalachia	10.0	9.1	10.5
Total	32.2	27.0	40.0

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



Illinois Basin Operations:

1. GIBSON COMPLEX
Gibson South Mine
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

Appalachian Operations:

6. MC MINING COMPLEX
Excel Mine No. 5
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Low-Sulfur
Transportation: Barge, Railroad, & Truck

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

8. 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

We lease most of our coal mineral reserves and resources from Alliance Resource Properties or private parties 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 mineral reserve or resource 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, 2021, we have 1,862 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 or transported by rail on the CSX Transportation, Inc. ("CSX") or Norfolk Southern Railway Company ("NS") railroads from our rail loadout facility directly to customers or 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.

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, 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, or NS rail directly to customers or 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 (multi-seam) 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 or Paducah & Louisville Railway, Inc. ("PAL") railroads or by truck 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. In 2021, the terminal loaded approximately 1.4 million tons for customers of Gibson County Coal and Hamilton.

Appalachian Operations

Our Appalachian mining operations are located in eastern Kentucky, Maryland, and West Virginia. As of December 31, 2021, we had 895 employees, and we operate three mining complexes in Appalachia.

MC Mining Complex. The MC Mining Complex is located near the city of Pikeville in Pike County, Kentucky. We acquired the original mine in 1989. Our subsidiary, MC Mining, LLC ("MC Mining"), through our subsidiary, Excel Mining, LLC ("Excel") operates the Excel Mine No. 5. Excel completed development of Mine No. 5 in May 2020 and transitioned its employees and equipment from Mine No. 4 in July 2020. The underground operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The existing preparation plant, which has throughput capacity of 1,000 tons of raw coal per hour, is utilized by Mine No. 5. Substantially all of the coal produced at MC Mining in 2021 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 various transloading facilities on the Ohio River for barge deliveries, or by truck directly to customers or to various docks on the Big Sandy River for barge deliveries.

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) 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. 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.

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 some utility customers have appeared to favor a shorter-term contracting strategy, in 2021 approximately 77.9% and 75.1% of our sales tonnage and total coal sales, respectively, were sold under long-term contracts with committed term expirations ranging from 2021 to 2026. As of February 11, 2022, our nominal commitment under contract was approximately 33.1 million tons for delivery in 2022. 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.

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 is 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 the 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 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, 2021, 2020, and 2019, export tons represented approximately 12.5%, 3.3%, and 17.9% of tons sold, respectively. 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

In 2021, we derived more than 10% of our total revenue from Louisville Gas and Electric Company. We did not derive 10% or more of our revenues from any other single customer. For more information about this customer, please read "Item 8. Financial Statement and Supplemental Data—Note 23 – 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 American Consolidated Natural Resources Inc., CONSOL Energy, Inc., Alpha Metallurgical Resources, Inc., Foresight Energy LP, and Peabody Energy Corporation. We also compete directly with smaller producers in the Illinois Basin and Appalachian regions. In addition, we seek to export a portion of our coal into the international coal markets and we compete with companies that produce coal from one or more foreign countries.

The prices we are able to 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. 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.

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 reflecting important flexibility advantages in supplying our customers. 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 can 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 53.1% of our 2021 sales volume was initially shipped from the mining complexes by barge, 31.9% was shipped from the mining complexes by rail, and 15.0% 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 ocean vessel transportation.

Mineral Interest Activities

Our mineral interest activities include both oil & gas and coal mineral interests. Our oil & gas 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' equity interest in AllDale Minerals III, L.P. ("AllDale III"). AR Midland acquired its mineral interests in the Wing and Boulders Acquisitions. Our mineral interests are primarily located on private lands 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 57,000 oil & gas net royalty acres, including 3,976 oil & gas net royalty acres owned through our equity interest in AllDale III.

Our coal mineral interests include all of our measured, indicated and inferred coal mineral resources and 422.9 million tons of coal mineral reserves which are owned or leased by Alliance Resource Properties and are (a) leased or subleased to internal mining complexes or (b) near other internal and external coal mining operations but not yet leased. Our coal mineral interests are located in both the Illinois Basin and the Appalachia Basin.

Oil & Gas Royalties

When our oil & gas 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, lease operating expenses or plugging and abandonment costs associated with oil & gas production.

The following chart summarizes the production of our oil & gas mineral interests for the year ended December 31, 2021, 2020, and 2019:

	Year Ended December 31,		
	2021	**2020**	**2019**
Production:			
Oil (MBbls)	825	948	741
Natural gas (MMcf)	3,490	3,635	3,664
Natural gas liquids (MBbls)	357	337	364
BOE (MBbls)	1,764	1,892	1,716

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

In 2014, we began to invest in oil & gas mineral interests in some of the nation's premier oil-rich basins. Beginning in 2019, we 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 Boulders 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 number 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.

Coal Royalties

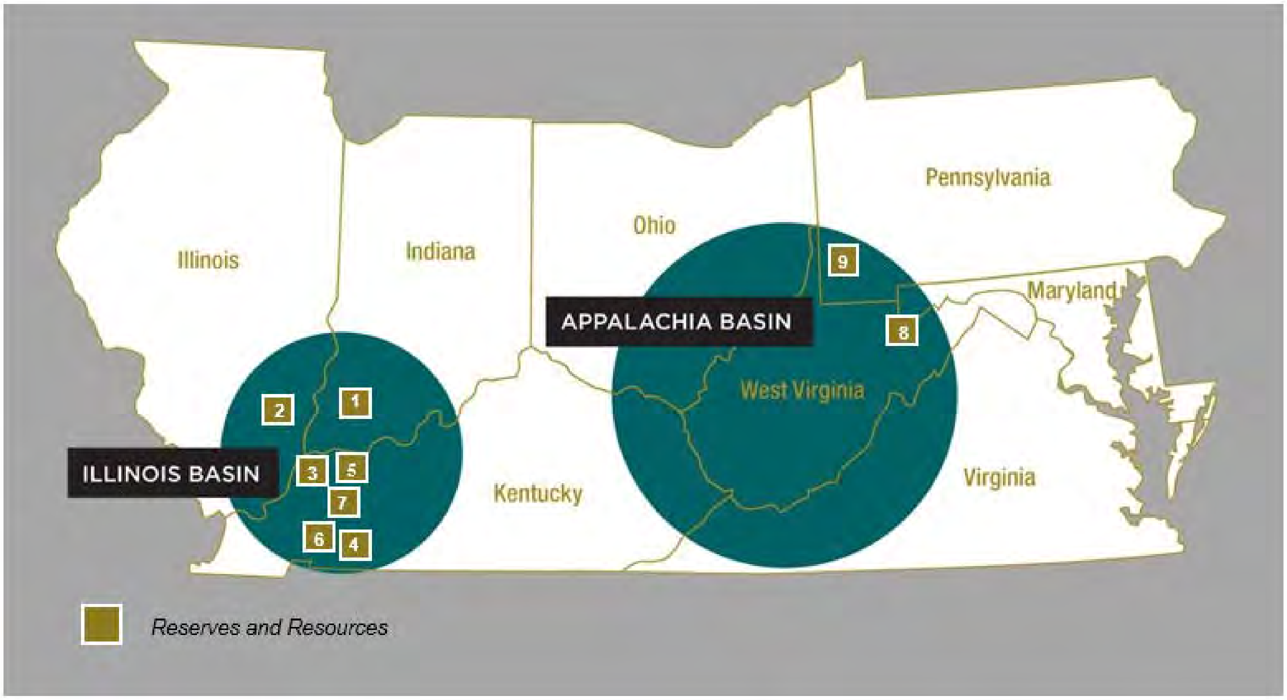
Our Coal Royalties segment includes approximately 422.9 million tons of proven and probable reserves and all of the 1.17 billion tons of our measured, indicated and inferred coal mineral resources. Our coal mineral reserves and resources are located in the Appalachia and Illinois Basins in the United States. We lease our reserves and resources to our mining complexes under long-term leases. Approximately two-thirds of our royalty-based leases have initial terms of five to 40 years, with substantially all lessees having the option to extend the lease for additional terms.

Under our standard royalty lease, we grant the lessees the right to mine and sell our reserves and resources in exchange for royalty payments based on a percentage of the sale price or a fixed royalty per ton of coal mined and sold. Lessees calculate royalty payments due to us and are required to report tons of coal mined and sold as well as the sales prices of the extracted coal.

The following chart summarizes the coal sales associated with our coal mineral interests for the years ended December 31, 2021, 2020 and 2019.

	Year Ended December 31,		
Coal Regions	**2021**	**2020**	**2019**
		(tons in millions)	
Illinois Basin	18.9	16.6	20.9
Appalachia	1.3	2.3	2.1
Total	20.2	18.9	23.0

The following map shows the location of our coal mineral interests:



Illinois Basin:
1. GIBSON
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Low/Medium-Sulfur
Transportation: Barge, Railroad & Truck

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

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

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

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

6. DOTIKI
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge, Railroad & Truck

7. SEBREE SOUTH
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge & Truck

Appalachian Basin:
8. MOUNTAIN VIEW
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall & Continuous Miner
Coal Type: Low/Medium Sulfur - Metallurgical
Transportation: Railroad & Truck

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

Illinois Basin

Our land holding company, Alliance Resource Properties, either directly or through its subsidiaries, holds coal mineral reserves and resources in the following counties in the Illinois Basin:

- Hopkins County, Kentucky
- Webster County, Kentucky

- Union County, Kentucky
- Henderson County, Kentucky
- Hamilton County, Illinois
- Jefferson County, Illinois
- Gibson County, Indiana

Alliance Resource Properties leases some of the reserves and resources in Union and Henderson Counties from WKY CoalPlay, LLC ("WKY CoalPlay") or its subsidiaries, which are related parties. For more information about our WKY CoalPlay transactions, please read "Item 8. Financial Statements and Supplementary Data—Note 21 – Related Party Transactions."

Gibson. Approximately 6.5 million tons of these reserves are currently leased/subleased or held for lease/sublease to our subsidiary, Gibson County Coal.

Hamilton. Approximately 128.5 million tons of these reserves are currently leased/subleased or held for lease/sublease to our subsidiary, Hamilton.

River View. Approximately 206.8 million tons of these reserves are currently leased/subleased or held for lease/sublease to our subsidiary, River View.

Warrior. Approximately 77.1 million tons of these reserves are currently leased/subleased or held for lease/sublease to our subsidiary, Warrior.

Dotiki. Approximately 76.0 million tons of these resources are currently leased/subleased or held for lease/sublease to our subsidiary, Webster County Coal, LLC ("Webster County Coal").

Sebree South. Approximately 43.5 million tons of these resources are currently leased/subleased to our subsidiary, Sebree Mining, LLC ("Sebree").

Other. Alliance Resource Properties holds miscellaneous non-strategic coal properties in the Illinois Basin that are not under lease or currently anticipated to be leased to any of our operating companies. Leasing of these properties is dependent upon further development by our operating subsidiaries or third-party mining complexes, which is regulatory and market dependent.

Appalachia Basin

Mountain View. Alliance Resource Properties holds coal mineral reserves and resources in Grant County and Tucker County, West Virginia, estimated to include approximately 10.7 million tons of medium sulfur coal, all of which is currently leased/subleased or held for lease/sublease to our subsidiary, Mettiki (WV).

Penn Ridge Resources. Alliance Resource Properties holds coal mineral resources in Washington County, Pennsylvania, (the "Penn Ridge Resources") estimated to include approximately 78.0 million tons of measured, indicated and inferred high-sulfur coal in the Pittsburgh No. 8 seam. These resources are near our Tunnel Ridge mining complex but are not currently leased. Leasing of these resources is dependent upon further development by Tunnel Ridge or third-party mining complexes, which is regulatory and market dependent.

Other. Alliance Resource Properties holds miscellaneous non-strategic coal properties in the Appalachia Basin that are not under lease. Leasing of these properties is dependent upon mining complexes nearby deciding to develop a project, which is regulatory and market dependent.

Minerals Interest Competition

Many companies are engaged in the search for and the acquisition of coal and oil & natural gas interests, and there is a limited supply of desirable coal and oil & natural gas reserves. Our ability to acquire additional oil & gas 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 oil & gas mineral interests but also explore for and produce oil & gas and, in some cases, conduct 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 alternative fuels and other forms of energy, may affect the demand for oil & gas.

We also face competition from land companies, coal producers and international steel companies in purchasing coal mineral reserves and resources as well as royalty producing properties. Numerous producers in the coal industry make coal marketing very competitive. Our mining complexes in which we lease our reserves compete with coal producers in various regions of the United States for domestic sales on the basis of coal price at the mine, coal quality, transportation cost from the mine to the customer, and the reliability of supply. Continued demand for our coal and the prices that our lessees obtain are also affected by demand for electricity and steel, as well as government regulations, technological developments, and the availability and the cost of generating power from alternative fuel sources, including nuclear, natural gas, wind, solar, and hydroelectric power.

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

Minerals Interest - 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 leasing 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.

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 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 data network, communication and tracking systems, mining proximity detection systems, industrial collision avoidance systems, and data and analytics software. We acquired Matrix Design in September 2006.

Additional Services

We develop and market additional services to establish ourselves as the supplier of choice for our customers. Historically, and in 2021, 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 reinterpretation 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 the 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 the 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.

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 estimated costs and timing assumptions 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 challenges, 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 the 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 the imposition of a civil penalty for each cited violation. Negligence and gravity assessments, along with 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.

MSHA has also published, and may continue to publish, various proposed rules or requests for information, which may result in additional rulemakings. For example:

- 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 for this matter, 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 2016 request for information. The comment period for the request for information for the Diesel Exhaust Partnership closed in September 2020.
- In August 2019, MSHA published a request for information regarding exposure to respirable crystalline silica, most commonly found in the mining environment through quartz. The request solicited information regarding best practices to protect miners' health from exposure to quartz, including examination of a new reduced permissible exposure limit, potential new or developing protective technologies, and/or technical and educational assistance. The comment period for the request for information closed in October 2019.
- In November 2020, MSHA published a proposed rule to revise Testing, Evaluation, and Approval of Electric Motor-Driven Mine Equipment and Accessories within underground mining environments. The comment period for the proposed rule closed in December 2020.
- In September 2021, MSHA published a proposed rule requiring that mine operators employing six or more miners develop and implement a written safety program for mobile and powered haulage equipment at surface mines and surface areas of underground mines (Safety Program for Surface Mobile Equipment). The comment period for the proposed rule closed in November 2021. However, MHSA reopened the rulemaking record for additional public comments. A virtual hearing was held in January 2022 and the comment period closed in February 2022.

It is uncertain whether MSHA will present a final rule addressing any of the above issues or any of the other various proposed rules or requests for information or whether any such rule would have material impacts on our operations or our costs of operation.

Subsequent to the 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, to some survivors of a miner who dies from this disease, and to a trust fund for the payment of benefits and medical expenses 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. Effective January 1, 2019, the trust fund was funded by an excise tax on production of up to $0.50 per ton for underground-mined coal and up to $0.25 per ton for surface-mined coal, but not to exceed 2% of the applicable sales price. Effective January 1, 2020, the trust fund was funded by an excise tax on coal sold of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price. Effective January 1, 2022, the trust fund is funded by an excise tax on production of up to $0.50 per ton for underground-mined coal and up to $0.25 per ton for surface-mined coal, but not to exceed 2% of the applicable sales price. It is uncertain as to whether the excise tax rates will be adjusted in the future or whether any such modifications would be retroactive.

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 refile 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 reclamation fee on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The fee expired on September 30, 2021, and was reauthorized through September 30, 2034, under the Infrastructure Investment and Jobs Act which was signed on November 15, 2021. The fee, as reauthorized, for surface-mined and underground-mined coal is $0.224 per ton and $0.096 per ton, respectively, through September 30, 2034. 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 U.S. 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. The Federal Office of Surface Mining ("OSM") has announced its 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 and in some cases it is unclear what level of collateral will be required. 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—*Cash Requirements*."

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.

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 2021, we sold 81.6% of our total tons to electric utilities in the United States, substantially all of which 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 impacts 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 U.S. 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." In May 2020, EPA issued a final rule that reverses the Agency's prior determination from 2000 and 2016 that it was "appropriate and necessary" to regulate hazardous air pollutants from coal-fueled Electric Generating Units ("EGUs") under the MATS rule. However, in February 2022, EPA published a proposed rule proposing to revoke the May 2020 finding. Although various issues surrounding the MATS rule remain subject to litigation in the D.C. Circuit, the MATS rule has forced electric power generators to make capital investments to retrofit power plants and could lead to additional premature retirements of older coal-fired generating units and many electric power generators have already announced retirements due to the uncertainty surrounding the MATS rule. 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 reevaluate 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. In March 2019, the EPA published a final rule that retained the current primary NAAQS for sulfur oxide. In December 2020, EPA published a final rule to retain the current NAAQS for both PM and ozone; however, various entities filed litigation against one or both of these rulemakings, and the Biden Administration has announced that it will reconsider and potentially revise the NAAQS and consider instituting a more stringent standard. 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 could indirectly reduce the demand for coal. Separately, the implementation of new standards by states has the 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 Federal Implementation Plans ("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, which was followed by a supplemental memorandum in July 2021 for SIPs for the second implementation period.

- 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 October 2020, the EPA finalized a rule to clarify the process for evaluating whether the NSR permitting program would apply to a proposed modification of a source of air emissions. The EPA has announced that it will review the NSR program. Depending on the ultimate resolution of the EPA's litigation and review, demand for coal could be affected.

- The EPA’s New Source Performance Standards ("NSPS") under the CAA require the reduction of certain pollutants 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 pneumatic controllers and storage vessels. Although the Trump Administration revised prior regulations in September 2020 to rescind certain methane standards and remove the transmission and storage segments from the source category for certain regulations, the U.S. Congress passed, and President Biden signed into law, a revocation of the 2020 rulemaking, effectively reinstating the 2016 standards. Additionally, in November 2021, EPA issued a proposed rule that, if finalized, would establish new source and first-time existing source standards of performance for GHG and volatile organic compound ("VOC") emissions for crude oil and natural gas well sites, natural gas gathering and boosting compressor stations, natural gas processing plants, and transmission and storage facilities. EPA plans to issue a supplemental proposal in 2022 containing additional requirements not included in the November 2021 proposed rule and anticipates the issuance of final rule by the end of the year. 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. Although no comprehensive climate change regulation has been adopted at the federal level in the United States, President Biden announced that climate change will be a focus of his administration. For example, in January 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil-fuel industry, a doubling of electricity generated by offshore wind by 2030, and increased emphasis on climate-related risks across governmental agencies and economic sectors. Internationally, the Paris Agreement requires member states to submit non-binding, individually-determined emissions reduction targets. These commitments could further reduce demand and prices for fossil fuels. Although the United States had withdrawn from the Paris Agreement, President Biden recommitted the United States in February 2021 and, in April 2021, announced a new, more rigorous nationally determined emissions reduction level of 50-52% reduction from 2005 levels in economy-wide net GHG emissions by 2030. The international community gathered again in Glasgow in November 2021 at the 26th Conference to the Parties ("COP26") during which multiple announcements were made, including a call for parties to eliminate fossil fuel subsidies, among other measures. Relatedly, the United States and European Union jointly announced at COP26 the launch of the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. Also at COP26, more than forty countries pledged to phase out coal, although the United States did not sign the pledge. The impact of these actions remain unclear at this time. 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 U.S. Supreme Court's 2007 decision that the EPA has authority to regulate GHG emissions. Although the U.S. 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. Several rulemakings have been issued under the NSPS that constrain the GHG emissions of fossil-fuel-fired power plants. In January 2021, the EPA published a final significant contribution finding for purposes of regulating source category of GHG emissions, confirming that such power plants are a source category for such regulations. However, this finding also excludes several sectors and may, therefore, be subject to revision, and 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 U.S. Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the U.S. Court of Appeals for the District of Columbia ("Circuit Court") even issued a decision. Then, in October 2017 the EPA proposed to repeal the CPP. The EPA subsequently proposed the Affordable Clean Energy ("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 CPP and promulgation of the ACE rule. The EPA's attempts to replace the CPP with the ACE rule are currently subject to litigation, and on January 19, 2021, the Circuit Court struck down the ACE rule, though the case is not yet final with oral arguments scheduled before the U.S. Supreme Court on February 28, 2022. We cannot predict the outcome of the litigation.

Notwithstanding the ACE rule, 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 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. In December 2021, President Biden issued an executive order setting a goal for a carbon pollution-free electricity sector across the country by 2035. 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 the long-term demand for our coal and the oil & gas producers from the properties in which we hold mineral interests. Finally, while the U.S. 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. For more information, see our risk factor titled "We, our customers, or the operators of our oil & gas mineral interests could be subject to litigation related to climate change."

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 July 2020, the Council on Environmental Quality ("CEQ") finalized revisions to NEPA regulations that clarify the extent to which direct, indirect, and cumulative environmental impacts from a proposed project, including GHG emissions, should be examined under NEPA. However, in October 2021, the CEQ published a proposed rule to restore, in general, NEPA regulations that were in effect before being modified by the 2020 revisions. A final rule is expected in 2022.

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 the 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 states and Canadian provinces have joined RGGI as participants or observers, while Virginia has withdrawn from RGGI via executive order by its governor.

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, though only California and certain Canadian provinces are currently active participants in the Western Climate Initiative. These regional efforts will likely 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. For more information, see our Risk Factor titled "Our operations are subject to a series of risks resulting from climate change."

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.

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 U.S. 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 which veto was subsequently upheld by the D.C. Circuit Court of Appeals in 2013. 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.

Total Maximum Daily Load ("TMDL") regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired waterbody 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. Rulemakings to establish the extent of such jurisdiction were finalized in 2015 and 2020, respectively, and both rulemakings have been subject to substantial litigation. On August 30, 2021, the US District Court for Arizona granted a request for voluntary remand of the EPA's rule. The Biden Administration has announced plans to establish its own definition of "waters of the United States" ("WOTUS"). Most recently, the EPA and the Corps of Engineers published a proposed rulemaking to revoke the 2020 rule in favor of a pre-2015 definition until a new definition is proposed, which the Biden Administration has announced is underway. Additionally, in January 2022, the Supreme Court agreed to hear a case on the scope and authority of the CWA and the definition of WOTUS. To the extent any decision expands the scope of the EPA and the Corps of Engineers' jurisdiction under the CWA, we could face increased costs and delays due to additional permitting and regulatory requirements and possible challenges to permitting decisions.

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 the 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. The CCB rule was subject to legal challenge and ultimately remanded to the EPA. On August 28, 2020, the EPA published a final revised rule mandating closure of unlined impoundments, with deadlines to initiate closure between 2021 and 2028, depending on site specific circumstances. Certain provisions of the revised CCB rule were vacated by the D.C. Circuit in 2018. The EPA is expected to finalize additional rules addressing those specific provisions in 2022 and 2023. Meanwhile, on January 25, 2022, the EPA published determinations for 9 of 57 CCB facilities who sought approval to continue disposal of CCB and non-CCB waste streams until 2023, as opposed to the initial 2021 deadline for unlined impoundments prescribed by the current rule. While the EPA issued one conditional approval, the EPA is requiring the remaining facilities to cease receipt of waste within 135 days of completion of public comment, or around July 2022. The current determinations, future determinations of the same nature, or similar actions in expected future rulemakings could lead to accelerated, abrupt, or unplanned suspension of coal-fired boilers. The combined effect of the CCB rules and ELG regulations (discussed below) has compelled power generating companies to close existing ash ponds and may force the closure of certain existing coal burning power plants that cannot comply with the new standards. Such retirements may adversely affect the demand for our 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. In October 2020, EPA published a final rule. In August 2021, EPA initiated supplemental rulemaking indicating that it intended to strengthen certain discharge limits. EPA expects to issue a proposed rule for public comment in fall 2022. 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 U.S. 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. In October 2021, the Biden Administration proposed the rollback of new rules promulgated under the Trump Administration; namely, the USFWS plans to rescind the 2018 rule that revised the process for designating critical habitat for threatened and endangered species under the ESA and second, alongside the National Marine Fisheries Service, the USFWS proposes to rescind the 2020 regulatory definition of "habitat." Final action on these proposed rules will occur in 2022. 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 regulations. 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.

Human Capital

To conduct our operations, as of December 31, 2021, we employed 2,990 full-time employees, including 2,604 employees involved in active coal mining operations, 219 employees in other operations, and 167 corporate employees. Our workforce is entirely union-free. Our typical employee has approximately eight years of experience with the Partnership and more than 50% of all employees remain employed for more than five years.

To attract and retain the most qualified personnel across all functions of our business we offer competitive compensation packages. In making decisions regarding employee compensation, we review current compensation levels for each position within other companies in the coal industry and other peers and use our discretion to determine an appropriate total compensation package, which generally includes some combination of base salary, possible incentive compensation, medical, dental and life insurance benefits and participation in our profit sharing and savings plan. Depending on the position and employer, incentive compensation bonuses can be based on production and safety goals at a specific coal operation or broader performance goals across the Partnership, among other factors. We intend for each employee's total compensation to be competitive in the marketplace.

Workplace safety is fundamental to our culture. By providing a work environment that rewards safety and encourages employee participation in the safety process, we strive to be the leader in safety performance in the coal mining industry. We are focused on improving employee safety through regular training and continuous monitoring of our progress, including through the mining industry standard of "non-fatal days lost," or "NFDL," which reflects both the frequency and severity of injuries incurred. Our NFDL rating of 3.26 for the year ended December 31, 2021, was below the preliminary industry average over the same time period. In addition, we collected over 13,000 respirable dust samples of the mining environment where our miners regularly work and travel. The average concentration of those samples was 59% below the regulatory standard. We are also regularly inspected by MSHA. For more information about citations or orders for violations of standards under the FMSHA, as amended by the MINER Act, please see our Exhibit 95.1 to this Annual Report on Form 10-K.

We are focused on the health of our employees. In addition to providing medical, dental, and vision insurance with no out-of-pocket premiums for our employees, we also provide on-site medical clinics to provide medical services to our employees and their families. Furthermore, at each of our coal operations and corporate offices, we provide a human resource representative to assist employees with various human resource matters. The Partnership also administers our medical plan, which allows us to control costs and work directly on behalf of our employees with health care providers enabling us in part, to continue providing health benefits with no out-of-pocket premiums for our employees.

We also have developed steps to enhance protections from, and minimize risks associated with, the spread of COVID-19, as needed. Such steps include or have included, without limitation, staggering shift patterns to promote social distancing, enhanced cleaning procedures, promotion of recommended hygiene practices, limited workplace access, "touch-free" check-in/check-out stations, wellness screening at mine locations, and requiring face coverings where appropriate.

ITEM 1A. RISK FACTORS

Summary Risk Factors

Our business is subject to a number of risks, including risks that could prevent us from achieving our business objectives or could adversely affect our business, financial condition, results of operations, cash flows, and prospects. These risks are discussed more fully below and include but are not limited to risks related to:

Risks Inherent in an Investment in Us

- Cash distributions are not guaranteed
- Ownership of limited partner interests could be diluted
- Sales of our common units could cause decline in the market price of our common units
- Increase in interest rates could cause decline in the market price of our common units
- The credit risk of our general partner could adversely impact us
- Our unitholders do not elect the general partner
- The control of our general partner may be transferred to a third party
- Unitholders may be required to sell their units to our general partner
- Cost reimbursements due to our general partner could be substantial
- Your liability as a limited partner may not be limited under certain circumstances
- Our general partner's fiduciary duties are limited
- Our general partner has discretion in determining the level of cash reserves
- Our general partner has potential conflicts of interest
- Some executive officers and directors face potential conflicts of interest
- ESG scores could adversely impact our securities

Risks Related to Our Business

- Declining global economic conditions could adversely impact us
- Material adverse effects on our financial condition as a result of the COVID-19 pandemic or future pandemic outbreaks could adversely impact us
- Financing may not be available to us on favorable terms or at all
- Our indebtedness could adversely impact us
- We depend upon the leadership of key personnel
- Legal proceedings could adversely impact us
- Our customers may not honor their contracts or may not enter into new contracts for our products
- Some of our contracts may be renegotiated or terminated
- We depend upon a few customers for significant portions of our revenues
- The credit risk of our customers could adversely impact us
- Cyber or terrorist attacks could adversely impact us
- Establishment of labor unions at our operations could adversely affect our profitability

Risks Related to Our Industries

- Changes in coal prices and/or oil & gas prices could impact our results of operations
- Competition within the coal industry could adversely affect our ability to sell coal
- Changes in taxes or tariffs and trade measures could adversely impact us
- Changes in consumption patterns by utilities could affect our ability to sell coal and/or impact the price of our natural gas
- Tort claims based on climate change
- Litigation resulting from disputes with customers could result in costs and liabilities
- Unanticipated mine operating conditions could affect our profitability
- Inability to obtain and renew permits necessary for operations could limit our ability to continue or expand our operations
- Fluctuations in transportation costs and availability could reduce demand for our products
- Unexpected increases in raw material costs could impact the profitability of our operations
- The ability to recruit, hire and retain skilled labor could impact the profitability of our operations
- Disruptions in supply chains could impact the profitability of our operations

- Inflationary pressures could impact the profitability of our operations
- Unavailability of economic coal mineral reserves and resources could limit our ability to continue or expand our operations
- Estimates of our coal mineral reserves and resources could be inaccurate and could result in decreased profitability
- Coal mining in certain areas could be difficult and involve regulatory constraints which could impact our operations
- Extensive environmental laws and regulations could reduce demand for coal as a fuel source
- Legislative and regulatory compliance is costly
- Legislative and regulatory compliance could impact our business
- Legislative and regulatory initiatives relating to hydraulic fracturing could impact our mineral interests
- Legislative and regulatory initiatives relating to seismic activity could impact our business
- Legislative and regulatory initiatives relating to climate change could impact demand for our products
- Mine facilities located in a leased portion of the surface properties which introduces a risk of disruption to our operations
- Inability to acquire or failure to maintain surety bonds could limit our ability to continue or expand our operations
- Dependency on unaffiliated operators to explore and drill on our oil & gas properties limits our ability to control the timing and quantity of production
- A lack of control over the timing of future drilling with respect to our mineral interests limits our ability to control the timing and quantity of production
- Delays in royalty payments and optional royalty payments could impact our business
- Suspension of right to receive royalty payments could impact our business
- Estimates of our oil & gas reserves could be inaccurate and could result in decreased profitability
- Uncertainties involved in drilling for and producing oil & gas could impact our business
- Availability of transportation and facilities for the products could impact our business
- Lack of hedging arrangements exposes us to the impact of commodity prices
- Expansions and acquisitions have inherent risks that could adversely impact us
- Integration of expansions or acquisitions have inherent risks that could adversely impact us
- Inability to obtain commercial insurance at acceptable rates could have a negative impact on our business

Tax Risks to Our Common Unitholders

- Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, and not being subject to a material amount of entity-level taxation. Our cash available for distribution to unitholders may be substantially reduced if we become subject to entity-level taxation as a result of the Internal Revenue Service ("IRS") treating us as a corporation or legislative, judicial, or administrative changes, and may also be reduced by any audit adjustments if imposed directly on the Partnership.
- Even if unitholders do not receive any cash distributions from us, unitholders will be required to pay taxes on their share of our taxable income. A unitholder's share of our taxable income may be increased as a result of the IRS successfully contesting any of the federal income tax positions we take.
- Tax gain or loss on the disposition of our units could be more than expected and create tax liabilities for our unitholders
- Limitation on unitholders ability to deduct interest expense incurred by us could create tax liabilities for our unitholders
- Tax Exempt entities and non-U.S. unitholders face unique tax issues from owning our common units that may result in adverse tax consequences to them
- IRS challenging our allocation of depreciation and amortization deductions could cause adverse tax consequences
- IRS challenging methods of prorating items of income, gain, loss, and deduction could cause adverse tax consequences
- Tax treatment as a partner for unitholders subject to securities loan could cause adverse tax consequences
- Certain federal income tax deductions currently available with respect to coal mining and production may be eliminated as a result of future legislation.
- Unitholders could be subject to state and local taxes and income tax return filing due to their status as a unitholder

Risks Inherent in an Investment in Us

Cash distributions to unitholders are not guaranteed.

The board of directors of our managing general partner ("Board of Directors") suspended cash distributions to unitholders beginning with the quarter ended March 31, 2020 due to uncertainty in the global economy caused by the COVID-19 pandemic, and resumed cash distributions following the quarter ended March 31, 2021. The payment and amount of any future distribution will be subject to the sole discretion of our Board of Directors and will depend upon many factors, including our financial condition and prospects, our capital requirements and access to financing, covenants associated with our debt obligations, and other factors that our Board of Directors may deem relevant, and there can be no assurance that we will pay a distribution in the future.

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 fluctuates 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;
- our debt service requirements and restrictions on distributions contained in our current or future debt agreements;
- fluctuations in our working capital needs;
- unavailability of financing resulting in unanticipated liquidity constraints; 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 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 12 – 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 could increase the risk that we will not have sufficient available cash to make distributions.

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 could decrease;
- the relative voting strength of each previously outstanding unit could be diminished;
- the ratio of taxable income to distributions could increase; and
- the market price of our common units could 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 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 could 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 could 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 could 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 annual or other continuing bases. 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 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 us.

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

Before 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 21 – Related-Party Transactions."

Your liability as a limited partner may not be limited, and our unitholders could 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 established in many jurisdictions.

Under certain circumstances, our unitholders could 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 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 may 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 many 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 any acts or omissions if our general partner and those other persons acted in good faith.

All limited partners are bound by the provisions in the partnership agreement, including the provisions discussed above.

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 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 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, without the limitations, could constitute breaches of fiduciary duty are limited. Unitholders are deemed to have consented to some actions and conflicts of interest that could 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 direct us to borrow funds to permit the payment of distributions.

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 Alliance GP, LLC ("AGP"). These relationships could 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 could adversely affect our business, results of operations, and financial condition.

Increasing attention to ESG matters may negatively impact our business, financial results, and unit price.

Companies across all industries, including companies in the fossil-fuel industry, are facing increased scrutiny from stakeholders related to their ESG practices. Companies that do not adapt or comply with evolving investor or stakeholder expectations and standards, or are perceived to have not responded appropriately to ESG issues, regardless of any legal requirement to do so, may suffer reputational damage and the business, financial condition, and/ unit price of such companies could be materially and adversely affected. Several advocacy groups, both domestically and internationally, have campaigned for governmental and private action to promote change at public companies related to ESG matters, including through the investment and voting practices of investment advisers, public pension funds, universities, and other members of the investing community. These activities include increasing attention to and demands for action related to climate change, promoting the use of substitutes to fossil-fuel products, encouraging the divestment of fossil-fuel equities, and pressuring lenders to limit funding to companies engaged in the extraction of fossil-fuel reserves. These activities could increase costs, reduce demand for our coal and hydrocarbon products, reduce our profits, increase the potential for investigations and litigation, impair our brand, limit our choices for lenders, insurance providers and business partners, and have negative impacts on our unit price and access to capital markets.

In addition, certain organizations that provide corporate governance and other corporate risk information to investors and unitholders have developed scores and ratings to evaluate companies and investment funds based upon ESG or "sustainability" metrics. Currently, there are no universal standards for such scores or ratings, but consideration of sustainability evaluations is becoming more broadly accepted by investors. Indeed, many investment funds focus on positive ESG business practices and sustainability scores when making investments, whereas other funds may use certain ESG criteria to "screen" certain sectors, such as coal or fossil fuels more generally, out of their investments. In addition, investors, particularly institutional investors, use these scores to benchmark companies against their peers and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance or sell their interests in the company, particularly if its ESG performance does not improve. Moreover, certain members of the broader investment community may consider a company's sustainability score as a reputational or other factors in making an investment decision. Companies in the energy industry, and in particular those focused on coal, natural gas, or oil extraction, often do not score as well under ESG assessments compared to companies in other industries. Consequently, a low ESG or sustainability score could result in our securities, both debt and equity, being excluded from the portfolios of certain investment funds and investors, restricting our access to capital to fund our continuing operations and growth opportunities. Additionally, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees, which may adversely affect our operations.

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 could 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 could decline if economic conditions deteriorate, which could 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 could be restricted as a result of future economic conditions, which could materially impact our ability to grow our business, including the development of our coal mineral reserves and resources.

We face various risks related to pandemics and similar outbreaks, which have had and may continue to have material adverse effects on our business, financial position, results of operations, and/or cash flows.

We face a wide variety of risks related to pandemics, including the global outbreak of COVID-19. Since first reported in late 2019, the COVID-19 pandemic has dramatically impacted the global health and economic environment, including millions of confirmed cases, business slowdowns or shutdowns, government challenges, and market volatility of an unprecedented nature. Although we have, to date, managed to continue most of our operations, we cannot predict the future course of events nor can we assure that this global pandemic, including its economic impact, will not continue to have a material adverse impact on our business, financial position, results of operations and/or cash flows. The COVID-19 pandemic and related economic repercussions have created significant volatility, uncertainty, and turmoil in the coal and oil & gas industries. The COVID-19 outbreak and the responsive actions to limit the spread of the virus have significantly reduced global economic activity, resulting in a decline in the demand for coal, oil, natural gas, and other commodities. Our operations could be further impacted by the COVID-19 pandemic if significant portions of our workforce are unable to work effectively, including because of illness, quarantines, or absenteeism; steps the company has taken to protect health and well-being; government actions; facility closures; work slowdowns or stoppages; inadequate supplies or resources (such as reliable personal protective equipment, testing, and vaccines); or other circumstances related to COVID-19. Looking forward, we could be unable to perform fully on our contracts, we could experience interruptions in our business and we could incur liabilities and suffer losses as a result. We will continue to incur additional costs because of the COVID-19 outbreak, including protecting the health and well-being of our employees and as a result of impacts on operations and performance, which costs we may not be fully able to recover. We could be subject to additional regulatory requirements, enforcement actions, and litigation, again with costs and liabilities that are not fully recoverable or insured. The continued spread of COVID-19 could also affect our ability to hire, develop and retain our talented and diverse workforce, and to maintain our corporate culture. The impact of a government-enforced vaccine mandate may result in adverse impacts such as workforce attrition for us or reduced morale or efficiency. The continued global pandemic, including the economic impact, is likely also to cause further disruption in our supply chain. If our suppliers have increased challenges with their workforce (including as a result of illness, absenteeism, or government orders), facility closures, access to necessary components and supplies, access to capital, and access to fundamental support services (such as shipping and transportation), they could be unable to provide the agreed-upon goods and services in a timely, compliant and cost-effective manner. We could incur additional costs and delays in our business, including as a result of higher prices for materials and equipment and schedule delays. As a result of the COVID-19 crisis, there may be changes in our customers' priorities and practices, as our customers in both the United States and globally confront reduced demand. Our customers have and may continue to experience adverse effects as a result of the COVID-19 crisis which could impact their creditworthiness or their ability to make payment for our products. We continue to work with our stakeholders (including customers, employees, suppliers, and local communities) to address this global pandemic responsibly. We continue to monitor the situation, assess further possible implications to our employees, business, supply chain, and customers, and take certain actions to mitigate various adverse consequences. We expect that the longer the COVID-19 pandemic, including its economic disruption, continues, the greater the adverse impact on our business operations, financial performance, and results of operations could be. The ultimate impact of COVID-19 on our operational and financial performance in future periods remains uncertain and will depend on future pandemic-related developments, including the duration of the pandemic, potential subsequent waves of COVID-19 infection or potential new variants, the effectiveness and adoption of COVID-19 vaccines and therapeutics, supplier impacts and related government actions to prevent and manage disease spread, including the implementation of any federal, state, local or foreign vaccine mandates, all of which are uncertain and cannot be predicted.

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 could 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 could 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 could 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.

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

We had long-term indebtedness of $443.1 million as of December 31, 2021. 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 increase 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, engage in some transactions, and 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 8 – Long-Term Debt" for further discussion.

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. 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.

We and our subsidiaries are subject to various legal proceedings, which could 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 22 – Commitments and Contingencies" for further discussion.

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 2021, we sold approximately 77.9% 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 could make it more difficult for us to enter into long-term sales 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 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 sales contracts contain provisions that allow 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 sales contracts may provide only limited protection during adverse market conditions. In some circumstances, the failure of the parties to agree on a price under a reopener provision can also lead to the early termination of a contract.

Several of our long-term sales 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 could include labor disputes, mechanical malfunctions, and changes in government regulations, including changes in environmental regulations rendering the use of our coal inconsistent with the customer's environmental compliance strategies. Additionally, most of our long-term sales 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 sales 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.

In 2021, we derived more than 10% of our total revenues from Louisville Gas and Electric Company. If we were to lose this 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.

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."

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 and resources, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, could 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 could 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.

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

None of our employees are represented under collective bargaining agreements. However, our workforce 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 could still be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our operations.

Risks Related to Our Industries

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 adverse impact of the COVID-19 pandemic due to the reduction in demand, as well as impacts of the pandemic on our ability to produce coal and oil & gas;
- 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;
- supply chain and cost of raw materials for coal and oil & gas operations;
- 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 the supply of coal;
- international developments impacting the 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 could 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 could 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 could 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 could 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 could benefit coal producers operating in countries other than the United States. We could 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 could provide our foreign competitors with a competitive advantage. If our competitors' currencies decline against the United States dollar or foreign purchasers' local currencies, those competitors could 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.

Changes in taxes or tariffs and other trade measures by the United States and foreign governments could adversely affect our results of operations, financial position, and cash flows.

We pay certain taxes and fees related to our operations. Congress or state legislatures may seek to increase these taxes and fees that relate specifically to the coal industry. We cannot predict further developments, and such increases could have a material adverse effect on 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. In response to 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 could 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 and may do so in the future.

Our business is closely linked to the demand for electricity, and any changes in coal consumption by United States or international electric power generators would likely impact our business over the long term. The domestic electric power sector accounts for the vast majority of the total 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. Indirect 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 the most potential to displace a significant amount of coal-fired electric power generation in the near term, particularly from older, less efficient coal-fired powered generators.

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. 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.

Other factors, such as efficiency improvements associated with technologies powered by electricity have slowed electricity demand growth and could contribute to slower growth in the future. Further decreases in the demand for electricity, such as decreases that could be caused by a worsening of current economic conditions, could have a material adverse effect on the demand for coal and our business over the long term.

We, our customers, or the operators of our oil & gas mineral interests could be subject to litigation related to 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 U.S. 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. Separately, litigation has been brought against certain fossil-fuel companies alleging that they have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or consumers. 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.

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

From time to time, we have disputes with our customers over the provisions of 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 could 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 profitability could 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 the 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 December 1, 2021, 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 75 or 90 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, the insurance industry has been subject to efforts by environmental activists to restrict coverages available for fossil-fuel companies.

We could 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 could 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 could face difficulties in the future that could 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.

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 maintain production and could adversely affect revenues.

Political or financial instability, currency fluctuations, the outbreak of pandemics or other illnesses (such as the COVID-19 pandemic), labor unrest, transport capacity and costs, port security, weather conditions, natural disasters, or other events that could alter or suspend our operations, slow or disrupt port activities, or affect foreign trade are beyond our control and could materially disrupt our ability to participate in the export market for coal sales, which could adversely affect our sales and our results of operations.

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 could change unexpectedly. Inflationary pressures have and could continue to lead to price increases affecting many of the components of our operating expenses such as fuel, steel, and maintenance expense. There could 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.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs and could adversely affect our profitability.

Efficient coal mining using modern techniques and equipment requires skilled laborers, preferably with at least one year of experience and proficiency in multiple mining tasks. In recent years, a shortage of experienced coal miners has caused us to include some inexperienced staff in the operation of certain mining units, which decreases our productivity and increases our costs. This shortage of experienced coal miners is the result of a significant percentage of experienced coal miners reaching retirement age, combined with the difficulty of retaining existing workers in and attracting new workers to the coal industry. Thus, this shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our coal, which could adversely affect our profitability.

Disruptions in supply chains could significantly impair our operating profitability.

We are dependent upon vendors to supply mining equipment, safety equipment, supplies, and materials. If a vendor fails to deliver on its commitments, or if common carriers have difficulty providing capacity to meet demands for their services, we could experience reductions in our production or increased production costs, which could lead to reduced profitability and adversely affect our results of operations.

Inflationary pressures could significantly impair our operating profitability.

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. In addition to potential cost increases, inflation could cause a decline in global or regional economic conditions that reduce demand for our coal or oil & gas and could adversely affect our results of operations.

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

Our profitability depends substantially on our ability to mine coal mineral reserves and resources 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 and resources as we mine coal, our future success and growth depend, in part, upon our ability to acquire additional coal mineral reserves and resources that are economically recoverable. Replacement reserves and resources 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 or resources that we acquire, which could adversely affect our profitability and financial condition. Exhaustion of reserves and resources at particular mines also could 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 and resources 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 mineral reserves and resources could prove inaccurate and could result in decreased profitability.

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

Each of the factors which impacts reserve and resource estimation may vary considerably from the assumptions used in making the estimation and, as a result, the estimates in this report may not accurately reflect our actual coal reserves and resources. Actual production, revenues and expenditures with respect to our coal reserves will likely vary from the assumptions used in these estimates, and these variances may be material. Government regulations and other pressures may result in closure of coal-fired electric generating plants earlier than assumed. Such changes would reduce the economic viability of our mining operations and could have a material adverse impact on our operations and financial results. Additionally, the estimates of coal reserves and resources may be adversely affected in future fiscal periods by the SEC's recent rule amendments revising property disclosure requirements for publicly traded coal mining companies, with which we are complying for the first time in this report.

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 mineral 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 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.

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 could require further emission reductions and associated emission control expenditures. These laws and regulations could 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*," "—*GHG Emissions*" and "—*Hazardous Substances and Wastes*."

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 could be costly and time-consuming and could delay the 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*."

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 could 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 the 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 could 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 could ultimately impact our operators' ability and willingness to develop our properties.

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 the 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 could incur substantial costs to comply with these requirements, which could 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 about 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 business.

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, both Texas and Oklahoma have imposed certain limits on the permitting or operation of disposal wells in areas with increased instances of induced seismic events. In September 2021, the Texas Railroad Commission ("TRRC") issued a notice to operators in the Midland area to reduce saltwater disposal well activities and provide certain data to the TRRC. Subsequently, the TRRC ordered the indefinite suspension of all deep oil and gas produced water injection wells in the area, effective December 31, 2021.

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.

Our operations are subject to a series of risks resulting from climate change.

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 have resulted in a series of regulatory, political, litigation, and financial risks for our business. Global climate issues continue to attract public and scientific attention. Most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere could 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.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain sources in the United States, or constrain the emissions of powerplants (though such emissions restraints have been subject to challenge; for more information, see our regulatory disclosure titled "GHG emissions"). Additionally, relating to our oil and gas mineral interests, the U.S. Congress approved, and President Biden signed into law, a resolution under the Congressional Review Act to repeal September 2020 revisions to methane standards, effectively reinstating the more stringent 2016 standards. Furthermore, in November 2021, EPA issued a proposed rule that, if finalized, would establish new sources and first-time existing source standards of performance for methane and volatile organic compound emissions for oil and gas facilities. Operators of affected facilities will have to comply with specific standards of performance to include leak detection using optical gas imaging and subsequent repair requirement, and reduction of emissions by 95% through capture and control systems. EPA plans to issue a supplemental proposal in 2022 containing additional requirements not included in the November 2021 proposed rule and anticipates the issuance of final rule by the end of the year. We cannot predict the scope of any final methane regulatory requirements or the cost for our operators to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility.

Separately, various states and groups of states have adopted or are considering adopting legislation, regulations, or other regulatory initiatives that are focused on such areas as GHG cap-and-trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. Internationally, the Paris Agreement requires member states to submit non-binding, individually-determined emissions reduction targets. These commitments could further reduce demand and prices for fossil fuels. Although the United States had withdrawn from the Paris Agreement, following President Biden’s executive order in January 2021, the United States rejoined the Agreement and, in April 2021, established a goal of reducing economy-wide net GHG emissions 50-52% below levels by 2030. Additionally, at COP26 in Glasgow in November 2021, the United States and the European Union jointly announced the launch of a Global Methane Pledge committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. The full impact of these actions is uncertain at this time and it is unclear what additional initiatives may be adopted or implemented that may have adverse effects upon us and our operators' operations.

Governmental, scientific, and public concern over climate change has also resulted in increased political risks, including certain climate-related pledges made by certain candidates now in political office. In January 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil-fuel industry, a doubling of electricity generated by offshore wind by 2030, and increased emphasis on climate-related risks across governmental agencies and economic sectors. Other actions that may be pursued include restrictive requirements on new pipeline infrastructure or fossil-fuel export facilities or the promulgation of 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, regional GHG cap and trade programs, or the establishment of renewable energy requirements for utilities. Depending on the particular program, we, our customers, or operators of our mineral interests 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. For more information, see our risk factor titled "We, our customers, or the operators of our oil & gas mineral interests could be subject to litigation related to climate change."

Apart from governmental regulation, there are also increasing financial risks for fossil-fuel producers as stakeholders of fossil-fuel energy companies 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. For example, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil-fuel sector. In late 2020, the Federal Reserve announced it had joined the Network for Greening the Financial System ("NGFS"), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Subsequently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Although we cannot predict the effects of these actions, such limitation of investments in and financing, bonding, and insurance coverages for fossil-fuel energy companies could adversely affect our coal mining or oil & gas production activities. Additionally, the SEC announced its intention to promulgate rules requiring climate disclosures. Although the form and substance of these requirements is not yet known, this may result in additional costs to comply with any such disclosure requirements.

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 could result in either us or oil & gas operators restricting or canceling 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 economically. 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.

Climate change may also result in various physical risks, such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns that could adversely impact our operations, as well as those of our operators and their supply chain. Such physical risks may result in damage to our facilities or our operators' facilities or otherwise adversely impact operations which could decrease the production attributable to our mineral interests. We may not have insurance to cover these risks and the consequences for our or their operations could have a negative impact on the costs and revenues from operations.

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.

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 the 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 the availability of collateral for surety bond issuers due to the terms of our credit agreements; and
- the exercise by third-party surety bondholders 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, 2021, our total of such bonds was $254.5 million. We could 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.

We depend on unaffiliated operators for all of the exploration, development, and production of 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 of 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 could result in significant fluctuations in our oil & gas revenues.

We have little to no control over the timing of future drilling with respect to our oil & gas 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 the 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 could 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 could 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, could 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 could 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 could 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 is placed in suspense, our results of operations could be reduced significantly.

Our estimated oil & gas reserves are based on many assumptions that could 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 could be incorrect. Our estimates of proved reserves and related valuations as of December 31, 2021, were audited by Netherland, Sewell & Associates, Inc. ("NSAI"), which conducted a detailed review of all of our properties at that time using the 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 could prove incorrect. A meaningful portion of our reserve estimates is made without the benefit of lengthy production history, which is less reliable than estimates based on 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 ("FASB"), 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 could differ materially from those used in the present value estimate, and future net present value estimates using then-current prices and costs could 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—Oil & Gas Reserves" for more information on our reserves.

Drilling for and producing oil & gas are high-risk activities with many uncertainties that could 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 could 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 canceled, 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 could 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 could 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 commodity production from our properties, and we will be exposed to the impact of decreases in the price of such commodities.

We have not entered into hedging arrangements to establish, in advance, a price for the sale of the oil & gas or the coal produced from our properties, and we may not enter into such arrangements in the future. As a result, although we could realize the benefit of any short-term increase in the price, we will not be protected against decreases in the price 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 or coal. 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 could 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 could be limited in receiving the full benefit of increases in commodity 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.

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

Since our formation and the acquisition of our predecessor in August 1999, we have expanded our coal operations by adding and developing mines in existing, adjacent, and neighboring properties. Similarly, the profitability of our business depends significantly upon acquisitions to grow our coal and oil & gas reserves, production, and free cash flow. Our future growth could be limited if we are unable to continue to make acquisitions in either our coal operations or our royalties segments, 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.

Competition for acquisitions of coal and oil & gas mineral interests could 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 under acceptable terms. In addition, these acquisitions could be in geographic regions in which we do not currently hold properties, which could subject us to additional and unfamiliar legal and regulatory requirements. 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.

The process of integrating acquired assets could involve unforeseen difficulties and could require a disproportionate amount of our managerial and financial resources. If we are unable to successfully integrate the companies, businesses, or properties we acquire, our profitability could 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 expansion and acquisition opportunities;

- uncertainties in identifying the extent of all weaknesses, risks, contingent and other 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 could require us to incur indebtedness, seek equity capital, or both. 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.

The integration of any expansions or acquisitions that we complete will be subject to substantial risks.

Even if we make expansions or acquisitions that we believe will increase our coal or mineral revenue, any expansion or 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 properties, goodwill or other intangible assets, asset devaluation, or restructuring charges.

Our inability to obtain commercial insurance at acceptable rates or our failure to adequately reserve for self-insured exposures could 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 could increase substantially in the future and could 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 could go out of business or be otherwise unable to fulfill their contractual obligations or could 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 could try to hamper fossil-fuel companies by other means including pressuring insurance and surety companies into restricting access to certain needed coverages.

Tax Risks to Our Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, and our not being subject to a material amount of entity-level taxation. If the IRS were to treat us as a corporation for U.S. 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 common units depends largely on our being treated as a partnership for U.S. federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based 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 U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. 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 our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise 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 U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. Members of Congress have frequently proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including proposals that would eliminate our ability to qualify for partnership tax treatment. Recent proposals have provided for the expansion of the qualifying income exception for publicly traded partnerships in certain circumstance and other proposals have provided for the total elimination of the qualifying income exception upon which we rely for our partnership tax treatment. 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 U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future.

Any modification to the U.S. federal income tax laws and interpretation thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any similar or future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

If the IRS were to contest the U.S. federal income tax positions we take, it may adversely impact the market for our common 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 U.S. 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 common units and the price 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 could be reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties 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 might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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 U.S. 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 common 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 common units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your 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 common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as "IRAs") raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Tax-exempt entities should consult a tax advisor before investing in our common units.

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

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

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. 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. While the determination of a partner's "amount realized" generally includes any decrease of a partner's share of the partnership's liabilities, the Treasury regulations provide that the "amount realized" on a transfer of an interest in a publicly traded partnership, such as our common units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner's share of a publicly traded partnership's liabilities. The Treasury regulations and other guidance from the IRS provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2023. Thereafter, the obligation to withhold on a transfer of interests in a publicly traded partnership that is effected through a broker is imposed on the transferor's broker. Current and prospective non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

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

Because we cannot match transferors and transferees of common 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 common 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, such unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax 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 U.S. 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 the U.S. Congress have indicated a desire to eliminate certain key U.S. federal income tax provisions currently applicable to coal companies, including the percentage depletion allowance with respect to coal properties. Elimination of those provisions would not impact our financial statements or results of operations. However, elimination of such 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 common units.

In addition to U.S. 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 multiple 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 U.S. federal, foreign, 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 Mineral Resources and Reserves

Overview of Coal Properties

Our coal properties are located in the Illinois Basin and the Appalachia Basin. Our Illinois Basin properties are located in western Kentucky, southern Illinois, and southern Indiana. Our Appalachian properties are located in eastern Kentucky, Maryland, western Pennsylvania, and northern West Virginia. Mining operations on our coal properties consist of underground mines that produce bituminous coal that is sold to customers principally for electric power generation (thermal) and the production of steel (metallurgical). In addition to our coal mining operations, we also hold coal mineral interests that we lease/sublease to our operations or hold for lease/sublease to our operations or others. For a detailed overview of our coal mining operations and our coal royalty activities, please see "Item 1. Business—Coal Mining Operations" and "Item 1. Business—Mineral Interest Activities", respectively.

Evaluation and Review of Coal Mineral Resources and Reserves

Numerous uncertainties are inherent in estimating coal mineral resources and reserves, and the estimates are subject to change as additional information becomes available or circumstances change. Significant factors and assumptions related to the uncertainty in estimating coal mineral reserves and resources include:

- 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.

Each of the factors which impacts reserve and resource estimation may vary considerably from the assumptions used in making the estimation and, as a result, the estimates in this report may not accurately reflect our actual coal reserves and resources. Actual production, revenues and expenditures with respect to our coal reserves will likely vary from the assumptions used in these estimates, and these variances may be material. Government regulations and other pressures may result in closure of coal-fired electric generating plants earlier than assumed. Such changes would reduce the economic viability of our mining operations and could have a material adverse impact on our operations and financial results. Additionally, the estimates of coal reserves and resources may be adversely affected in future fiscal periods by the SEC's recent rule amendments revising property disclosure requirements for publicly traded coal mining companies, with which we are complying for the first time in this report.

Under SEC rules, a mineral resource is a concentration or occurrence of material of economic interest in or on the Earth's crust in such form, grade or quality, and quantity that there are reasonable prospects for economic extraction. A mineral resource is a reasonable estimate of mineralization, taking into account relevant factors such as cut-off grade, likely mining dimensions, location or continuity that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. A mineral reserve is an estimate of tonnage and grade or quality of indicated and measured mineral resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, it is the economically mineable part of a measured or indicated mineral resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted.

Our coal mineral resource and reserve estimates included in this Annual Report on Form 10-K were prepared by an independent, qualified engineering firm, RESPEC Company, LLC ("RESPEC"). We provided RESPEC with property control, mine plans, production, revenue, costs, capital, and other information considered by RESPEC in making their estimates. As part of our internal controls, our geologists and engineers review the integrity, accuracy, and timeliness of the data provided to RESPEC that they considered in calculating their coal mineral resource and reserve estimates. We also review the geologic data, mining assumptions, and methodology used by RESPEC to estimate our coal mineral resources and reserves. Our geologists and engineers also met with RESPEC periodically during the year to discuss the assumptions and methods used in the coal mineral resource and reserve estimation process.

RESPEC, an independent third-party engineering firm, does not own an interest in any of our properties and is not employed on a contingent basis. RESPEC's Technical Report Summaries for each of our material mining operations are included as exhibits to this Annual Report on Form 10-K.

Summary of Coal Mineral Resources and Reserves

Coal Mineral Resources

Most of our coal properties designated as mineral resources are of thickness, quality, and mineability similar to that of our mineral reserves, and all are proximal to existing infrastructure such as power, water, transportation, facilities, etc. However, we have not completed pre-feasibility or feasibility studies with respect to our coal properties designated as mineral resources, as is required to convert the mineral resources into mineral reserves. There is no certainty that all or any part of our mineral resources will be converted into mineral reserves.

The following table sets forth our coal mineral resources, exclusive of coal mineral reserves, at December 31, 2021:

Resources (tons in millions)	Heat Content (Btus per pound)	Pounds SO2 per MMBtu			Resource Classification				Ownership		
		<1.2	1.2-2.5	>2.5	Measured	Indicated	Combined (1)	Inferred	Owned	Leased	Total
Illinois Basin											
Dotiki (KY)	12,100	—	2.3	73.7	51.2	24.8	76.0	—	27.6	48.4	76.0
Henderson/Union (KY)	11,450	—	3.2	520.3	175.4	286.0	461.4	62.1	74.6	448.9	523.5
Sebree South (KY)	11,750	—	—	43.5	22.1	16.8	38.9	4.6	0.3	43.2	43.5
Hamilton County (IL)	11,650	5.1	33.8	398.8	187.1	239.3	426.4	11.3	32.6	405.1	437.7
Region Total		5.1	39.3	1,036.3	435.8	566.9	1,002.7	78.0	135.1	945.6	1,080.7
Appalachian Basin											
Mountain View (WV)	13,200	—	0.5	6.3	2.1	4.5	6.6	0.2	1.7	5.1	6.8
Penn Ridge (PA)	12,500	—	—	78.0	21.9	53.2	75.1	2.9	78.0	—	78.0
Region Total		—	0.5	84.3	24.0	57.7	81.7	3.1	79.7	5.1	84.8
Total		5.1	39.8	1,120.6	459.8	624.6	1,084.4	81.1	214.8	950.7	1,165.5
% of Total		0.4%	3.4%	96.1%	39.5%	53.6%	93.0%	7.0%	18.4%	81.6%	100.0%

(1) Combined resources are defined as measured plus indicated resources.

At December 31, 2021, we had approximately 1.165 billion tons of coal mineral resources. Tonnages are reported on a clean recoverable basis with pricing based on available third party forecasts and historical pricing adjusted for quality at the end of 2021 ranging from $36.00 to $67.00 per short ton, which are the prices used by RESPEC to estimate the amount of coal mineral resources. All resources are classified as underground mineable in the exploration stage.

Coal Mineral Reserves

Our reserves are assigned to our active operations and are (1) currently in production, (2) economically viable, and (3) meet the other requirements to be considered reserves as defined by the SEC.

The following table sets forth coal mineral reserve information, exclusive of the coal mineral resources above, at December 31, 2021, about our coal operations:

Reserves (tons in millions)	Heat Content (Btus per pound)	Pounds SO2 per MMBtu			Classification		Ownership		Total
		<1.2	1.2-2.5	>2.5	Proven	Probable	Owned	Leased	
Illinois Basin Operations									
Warrior (KY)	12,300	—	—	77.1	61.4	15.7	18.7	58.4	77.1
River View (KY)	11,450	—	—	214.6	117.8	96.8	62.0	152.6	214.6
Hamilton County (IL)	11,650	—	—	128.5	57.6	70.9	22.5	106.0	128.5
Gibson (South) (IN)	11,500	0.7	12.4	39.5	44.2	8.4	18.3	34.3	52.6
Region Total		0.7	12.4	459.7	281.0	191.8	121.5	351.3	472.8
Appalachian Basin Operations									
MC Mining (KY)	12,800	11.9	1.0	—	9.1	3.8	—	12.9	12.9
Mountain View (WV)	13,200	—	4.2	3.5	6.4	1.3	—	7.7	7.7
Tunnel Ridge (WV)	12,600	—	—	53.7	28.6	25.1	—	53.7	53.7
Region Total		11.9	5.2	57.2	44.1	30.2	—	74.3	74.3
Total		12.6	17.6	516.9	325.1	222.0	121.5	425.6	547.1
% of Total		2.3%	3.2%	94.5%	59.4%	40.6%	22.2%	77.8%	100.0%

On December 31, 2021, we had approximately 547.1 million tons of coal mineral reserves. Tonnages are reported on a clean recoverable basis with pricing based on available third party forecasts and historical pricing adjusted for quality at the end of 2021 ranging from $36.00 to $67.00 per short ton, which are the prices used by RESPEC to estimate the amount of coal mineral reserves. All reserves are classified as underground mineable in the production stage.

Mining Operations

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

Operations	Location	Tons Produced 2021	2020	2019	Transportation	Equipment
		(in millions)				
Illinois Basin Operations						
Dotiki (1)	Kentucky	—	—	1.3	CSX, PAL, truck, barge	CM
Warrior	Kentucky	4.1	3.6	3.7	CSX, NS, PAL, truck, barge	CM
River View	Kentucky	9.9	9.4	11.3	Truck, barge	CM
Hamilton County	Illinois	4.9	2.6	5.9	CSX, EVW, NS, barge	LW, CM
Gibson (North) (1)	Indiana	—	—	1.8	CSX, NS, truck, barge	CM
Gibson (South)	Indiana	3.3	2.3	5.5	CSX, NS, truck, barge	CM
Region Total		22.2	17.9	29.5		
Appalachian Basin Operations						
MC Mining/Excel	Kentucky	1.3	0.5	1.0	CSX, truck, barge	CM
Mountain View	West Virginia	1.5	1.8	2.1	CSX, truck	LW, CM
Tunnel Ridge	West Virginia	7.2	6.8	7.4	CSX, NS, barge	LW, CM
Region Total		10.0	9.1	10.5		
TOTAL		32.2	27.0	40.0		

(1) Closed

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

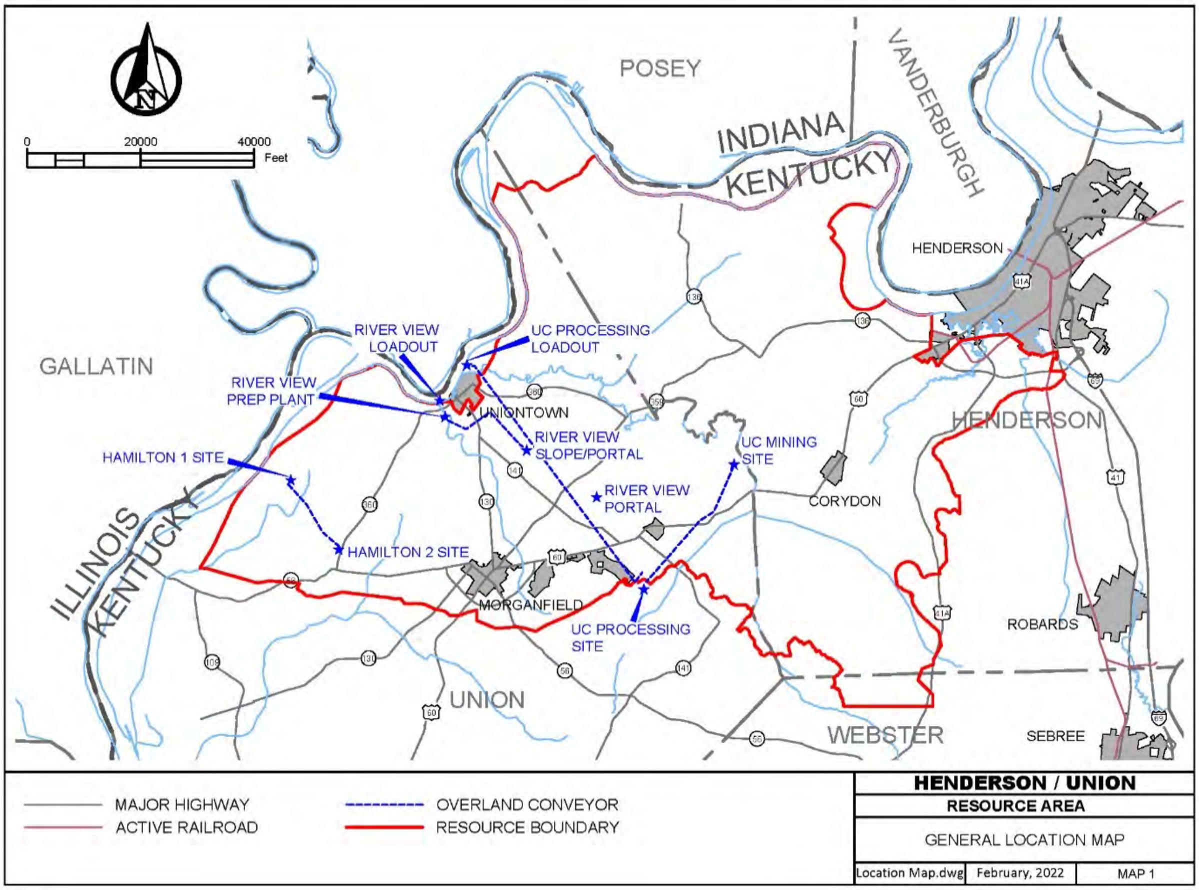
Individual Property Disclosures

We consider the following properties to be material based on multiple factors including, but not limited to, the property's contribution to our overall business and financial condition. Please see Coal Mineral Resources and Coal Mineral Reserves sections above for information about the coal mineral resources and reserves held by these material properties. In addition to the following information, Technical Report Summaries for these material properties with additional information are included as exhibits to this Annual Report on Form 10-K.

Henderson/Union

The Henderson/Union Resources are located in Henderson and Union counties, Kentucky at 37°44'30"N, -87°46'07"W and currently have control in over 1,600 tracts encompassing over 127,000 acres. The property is controlled through both fee ownership and leases of the coal. Existing and proposed facilities are on controlled land. The coal mineral resources are controlled by Alliance Resource Properties. The base leases are with private owners and WKY CoalPlay or its subsidiaries, which are related parties. See "Item 8. Financial Statements and Supplementary Data—Note 21 – Related Party Transactions" for more information about our WKY CoalPlay transactions. These base leases generally provide for a term that can be extended until exhaustion of the leased coal. Local infrastructure is as follows:

Major Roads: Interstates 69 and US-60,
Railroads: None,
Airport: Evansville Regional Airport (EVV),
Town: Morganfield,
Docks: River View, Hamilton 1, UC Processing, on the Ohio River,
Water: Local municipalities and mine sources,
Electricity: Kentucky Utilities (KU),
Personnel: Regional.



Description

The potential underground mine(s) would utilize room-and-pillar methods operating a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill possible permitting and development requirements. Multiple access points are available for development. Access is available from the active River View mine, which began production in 2009. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Access at the Hamilton and UC Coal, LLC sites are considered "brownfield" developments. Though some facilities and permitting are in place, significant upgrades to existing infrastructure and new construction would be needed to bring them into good working order that meets industry standards. The property associated with Henderson/Union has no book value as of December 31, 2021 but does have outstanding advanced royalties with WKY CoalPlay or its subsidiaries. See "Item 8. Financial Statements and Supplementary Data—Note 21 – Related Party Transactions" for more information about advanced royalties that Henderson/Union has with WKY CoalPlay.

History

The Henderson/Union property contains resources in four seams, the West Kentucky No. 11 (WKY11), the West Kentucky No. 9 (WKY9), the West Kentucky No. 7 (WKY7), and the West Kentucky No. 6 (WKY6). Island Creek Coal Company ("Island Creek") operated mines in the area and controlled a portion of the property. Under a joint venture, Texas Gas Service also controlled a large interest in the mineral rights. Lastly, Peabody Coal Corporation ("Peabody") and Patriot Coal Corporation ("Patriot") operated mines in the area and controlled a portion of the reserves. We consolidated control of the property through multiple transactions from 2005 through 2015. Island Creek operated the Ohio #11 and Uniontown #9 mines. Island Creek also operated the Hamilton #1 and #2 mines in Kentucky. Peabody and later Patriot operated the Camp complex and Highland mines to the southeast and east. Both the WKY9 and WKY11 seams were mined at these locations. No mining has occurred on the property in the WKY7 or WKY6 seams.

Approximately 1,050 exploration holes have been drilled within and adjacent to the Henderson/Union area to assess thickness and mineability of the WKY11, WKY9, WKY7, and WKY6 seams. From these holes, over 410 samples were collected and analyzed to determine coal quality characteristics. Also, over 150 oil/gas well geophysical logs drilled by various companies have been interpreted to supplement the exploration drilling. In general, all drilling has shown highly consistent coal seams of mineable thickness and quality for the high sulfur, thermal utility market.

Encumbrances

Our revolving credit facility is secured by, among other things, liens against certain Henderson/Union surface properties and coal leases. Documentation of such liens is of record in the Offices of the Henderson and Union County Clerks. Please read "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-term Debt" for more information on our revolving credit facility.

The Kentucky Department of Natural Resources ("KYDNR"), Division of Mine Permits ("DMP") is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations. In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining.

Geology and Reserves

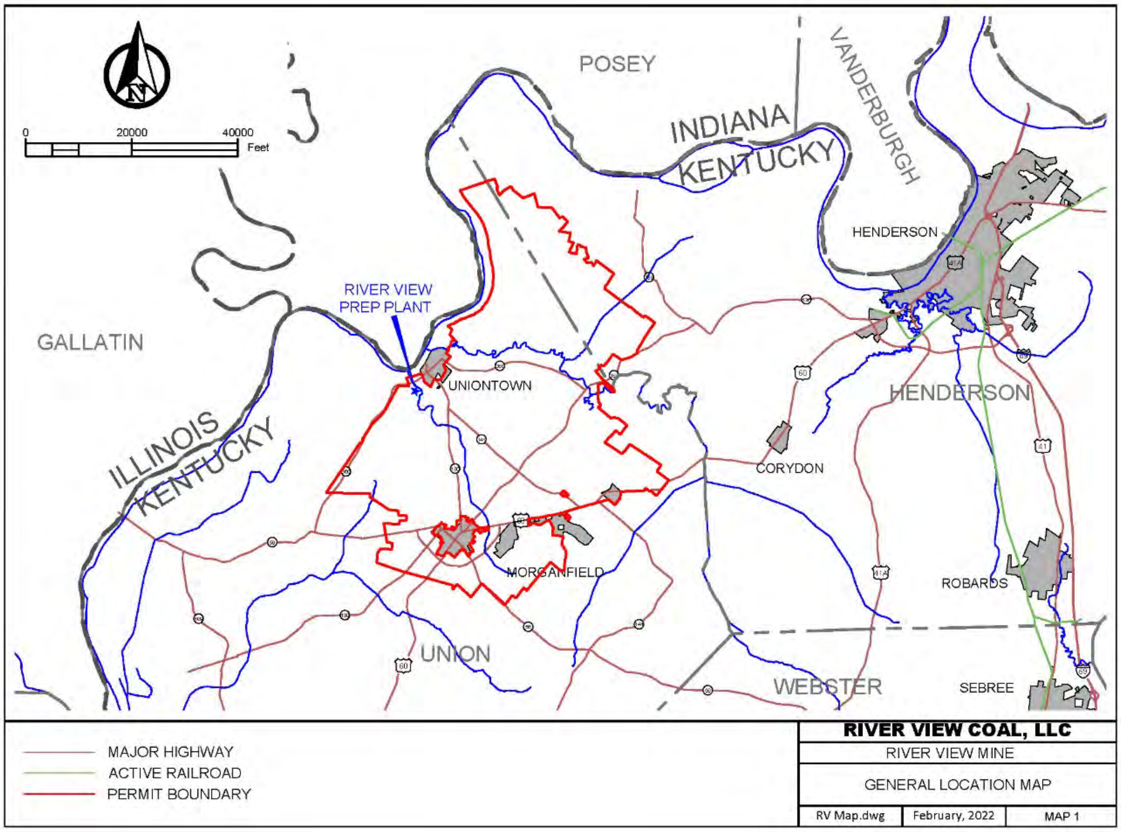
Henderson/Union contains coal resources in four seams ranging in depths from about 100 to 750 feet. The table below summarizes mineral resources as of December 31, 2021 using a cut off thickness of 4.00 feet:

			Quality, Washed, Dry Basis				% Recovery	
Resources	**Tons (millions)**	**Thickness (ft)**	**% Ash**	**% Sulfur**	**Btu**	**lbs. SO2**	**In-Seam**	**Prep Plant**
Henderson/Union								
Measured Mineral Resources	175.4	4.71	8.15	3.01	13,241	4.54	87.10	54.76
Indicated Mineral Resources	286.0	4.62	8.23	2.86	13,242	4.33	88.03	53.77
Combined Mineral Resources	461.4	4.66	8.20	2.92	13,241	4.41	87.67	54.14
Inferred Mineral Resources	62.1	4.48	8.16	2.60	13,321	3.91	89.66	52.14

River View

River View is located in Union County, Kentucky at 37°45'37"N, -87°56'42"W and currently has approximately 54,250 underground acres permitted. The mine is controlled through both fee ownership and leases of the coal. The coal mineral reserves are leased or held for lease to River View by Alliance Resource Properties. River View either owns or controls the surface properties upon which its facilities are located including the preparation plant, refuse areas, mine offices, conveyor systems, shafts and slopes. The coal mineral reserves currently assigned to and controlled by River View are pursuant to a 2009 Coal Lease and Sublease Agreement from Alliance Resource Properties. The base leases are with private owners and generally provide for a term that can be extended until exhaustion of the leased coal. Local infrastructure is as follows:

Major Roads: Interstates 69 and US-60,
Railroads: None,
Airport: Evansville Regional Airport (EVV),
Town: Morganfield,
Docks: River View on the Ohio River,
Water: Uniontown Water Department and mine sources,
Electricity: Kentucky Utilities (KU),
Personnel: Regional.



Description

The underground mine is currently in production using room-and-pillar methods utilizing a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill mining and permitting requirements. The mine began production in 2009. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Total book value of the property and any associated plant and equipment for River View as of December 31, 2021 was $199.3 million.

History

Island Creek operated mines in the area and controlled a portion of the property. Under a joint venture, Texas Gas Service also controlled a large interest in the mineral rights. Lastly, Peabody and Patriot operated mines in the area and controlled a smaller portion of the reserves. We consolidated control of the property through multiple transactions from 2005 through 2015. Island Creek operated the Ohio #11 and Uniontown #9 mines to the west of River View. Island Creek also operated the Hamilton #1 and #2 mines to the southwest. Peabody and later Patriot operated the Camp complex and Highland mines to the southeast and east. Both the WKY9 and WKY11 seams were mined at these locations.

Approximately 630 exploration holes penetrate the WKY11 seam and about 450 holes penetrate the WKY9 seam within and adjacent to the River View resource/reserve area to assess thickness, quality, and mineability of the seams. River View has drilled over 80 holes on the property to supplement the historic data. Also, over 300 oil/gas well geophysical logs drilled by various companies have been interpreted to supplement the exploration drilling.

Encumbrances

Our revolving credit facility is secured by, among other things, liens against certain River View surface properties and coal leases. Documentation of such liens is of record in the Office of the Union County Clerk. Please read "Item 8.

Financial Statements and Supplementary Data—Note 8 – Long-term Debt" for more information on our revolving credit facility.

Accounts receivable generated from the sale of coal mined from this property are collateral for our accounts receivable securitization facility, evidenced by financing statements of record in the Office of the Union County Clerk. Please read "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-term Debt" for more information on our accounts receivable securitization facility.

The KYDNR, DMP is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations. In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining. All applicable permits for underground mining, coal preparation and related facilities, and other incidental activities have been obtained and remain in good standing.

Geology and Reserves

River View extracts coal underground from the West Kentucky No. 11 and No. 9 seams at depths ranging from 200 to 500 feet. The table below summarizes mineral reserves as of December 31, 2021 using a cut off thickness of 4.00 feet:

			Quality, Washed, Dry Basis				% Recovery	
Reserves	**Tons (millions)**	**Thickness (ft)**	**% Ash**	**% Sulfur**	**Btu**	**lbs. SO2**	**In-Seam**	**Prep Plant**
River View								
Proven Mineral Reserves	117.8	4.69	7.57	3.13	13,284	4.71	86.46	53.80
Probable Mineral Reserves	96.8	4.60	7.71	3.11	13,235	4.71	86.24	52.19
Total Mineral Reserves	214.6	4.65	7.63	3.12	13,262	4.71	86.36	53.07

The River View mine had 223.3 million tons of coal mineral reserves at the end of 2020. The year over year reconciliation is as follows:

River View Yearly Reserve Reconciliation	**(millions)**
Tons as of December 31, 2020	223.3
Production	(9.9)
Mineral Acquisition / Deletion	0.9
Normal Course Adjustments	0.3
Tons as of December 31, 2021	214.6

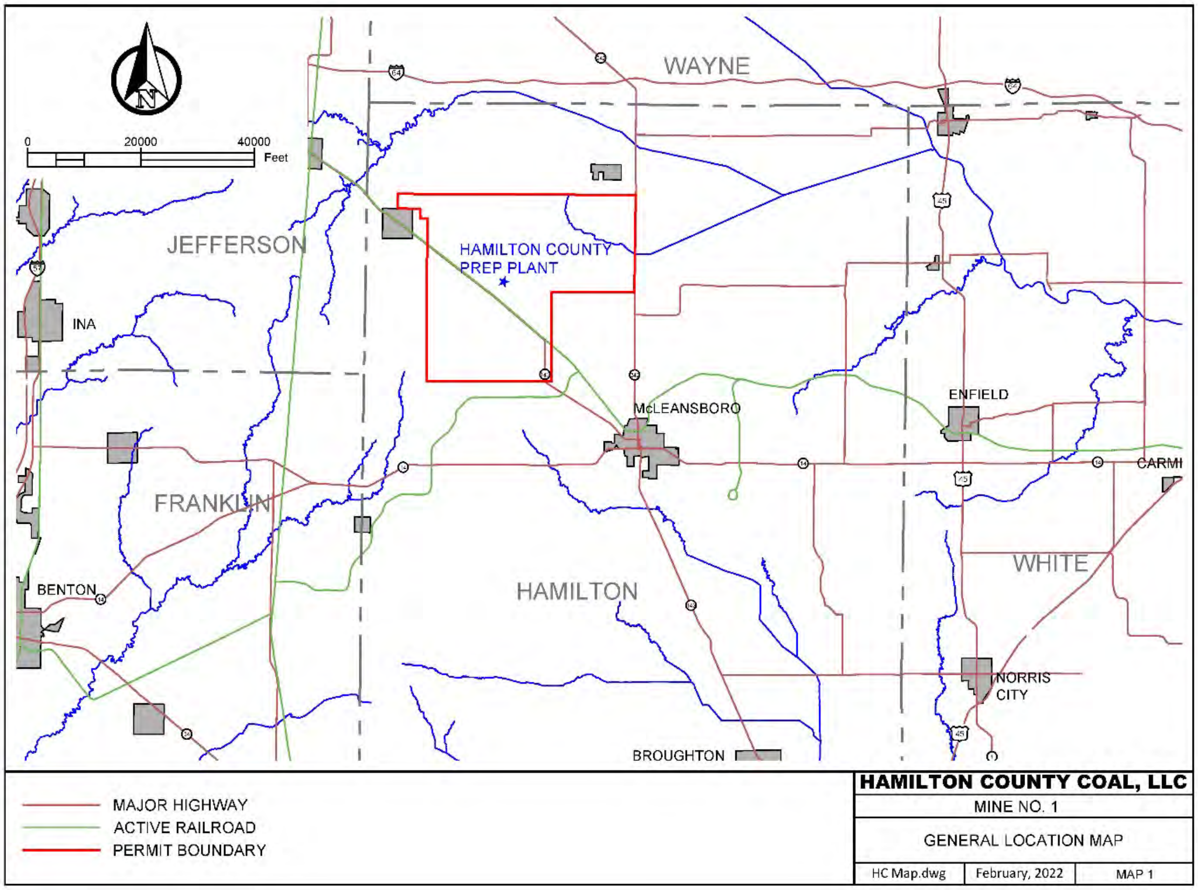
Normal course adjustments are associated with numerous slight changes in the geologic model.

Hamilton

Hamilton, a longwall mine located in Hamilton County, Illinois at 38°10'12”N, -88°36'47"W, currently has approximately 10,500 underground acres and 1,300 surface acres permitted. The mine property is controlled through both fee ownership and leases of the coal. The coal mineral reserves and resources are leased or held for lease to Hamilton by Alliance WOR Properties, LLC ("Alliance WOR Properties"), a subsidiary of Alliance Resource Properties. Hamilton either owns or controls the surface properties upon which its facilities are located including the preparation plant, refuse areas, mine offices, conveyor systems, shafts and slopes. Hamilton (or Alliance WOR Properties) currently controls approximately 53,348 acres of coal mineral reserves and resources and subsidence rights, and 1,400 acres of surface properties. The underlying base coal leases are with private owners and are comprised of a large number of leases originally taken by AMAX Coal Company and Old Ben Coal Company ("Old Ben") in the mid to late 1970’s and early 1980’s (the "Old Ben Leases"), leases acquired by Consolidation Coal Company in the late 1980’s (the "Consol Leases"), and subsequent leases taken directly by White Oak Resources, LLC or affiliated companies and/or Alliance WOR Properties. Local infrastructure is as follows:

Major Roads: Interstates 64,
Railroads: CSX and EVW,
Airport: Evansville Regional Airport (EVV),
Towns: McLeansboro and Mt. Vernon,

Docks: Mount Vernon on the Ohio River,
Water: Hamilton County Water District and mine sources,
Electricity: Wayne-White Electric Co-op (WWEC),
Personnel: Regional.



Description

The underground mine is currently in production using longwall and room-and-pillar methods utilizing a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill mining and permitting requirements. The mine began production in 2014. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Total book value of the property and any associated plant and equipment for Hamilton as of December 31, 2021 was $347.1 million.

History

There were no previous operations on the Hamilton reserves property prior to our predecessor, White Oak Resources LLC, who began construction of the mine in 2011.

Over 180 exploration holes have been drilled in the Hamilton reserve area by other companies to assess thickness, quality, and mineability of the Herrin and Harrisburg seams. White Oak Resources LLC drilled over 90 holes in the reserve area starting in 2008. Also, over 70 oil/gas well geophysical logs drilled by various companies have been interpreted to supplement the exploration drilling.

Encumbrances

Our revolving credit facility is secured by, among other things, liens against certain Hamilton surface properties, coal leases and owned coal. Documentation of such liens is of record in the Office of the Hamilton County Clerk. Please read "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-term Debt" for more information on our revolving credit facility.

The Consol Leases are encumbered by an overriding royalty payable to Sustainable Conservation, Inc. ("Sustainable") in the amount of the greater of $0.25 per ton or 0.75% of the average sales realization price received per ton, which sums can be credited against approximately $481,000.00 previously paid to Sustainable for the assignment of the Consol Leases.

The Illinois Department of Natural Resources, Land Reclamation Division is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations. In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining. All applicable permits for underground mining, coal preparation and related facilities and other incidental activities have been obtained and remain in good standing.

Geology and Reserves

Hamilton extracts coal underground from the Herrin (Illinois No.6) seam at depths ranging from 900 to 1100 feet. The table below summarizes mineral reserves as of December 31, 2021 using a cut off thickness of 4.00 feet:

			Quality, Washed, Dry Basis				% Recovery	
Reserves	**Tons (millions)**	**Thickness (ft)**	**% Ash**	**% Sulfur**	**Btu**	**lbs. SO2**	**In-Seam**	**Prep Plant**
Hamilton County								
Proven Mineral Reserves	57.6	6.37	8.04	2.81	13,407	4.20	86.71	53.85
Probable Mineral Reserves	70.9	6.63	7.99	2.83	13,423	4.21	86.82	57.34
Total Mineral Reserves	128.5	6.52	8.01	2.82	13,416	4.21	86.77	55.78

The Hamilton mine had 125.0 million tons of coal mineral reserves at the end of 2020. The year over year reconciliation is as follows:

Hamilton County Yearly Reserve Reconciliation	**(millions)**
Tons as of December 31, 2020	125.0
Production	(4.9)
Mineral Acquisition / Deletion	1.0
Mine Plan Adjustment	6.7
Normal Course Adjustments	0.7
Tons as of December 31, 2021	128.5

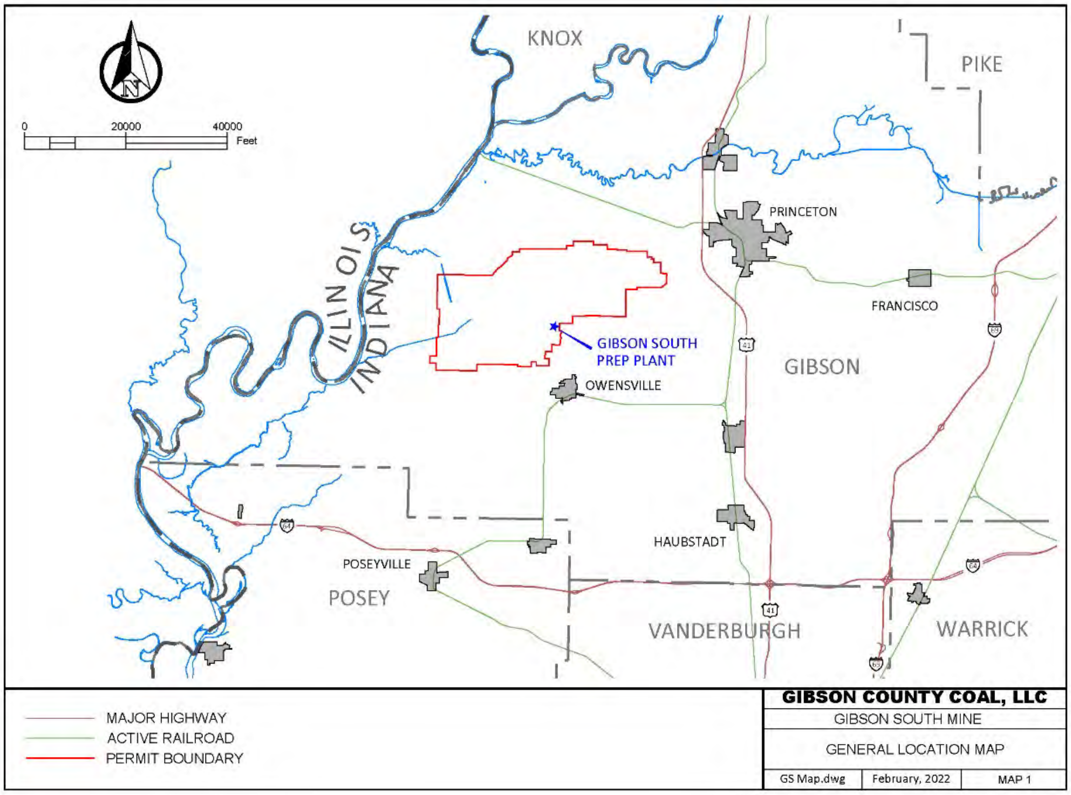
Normal course adjustments are associated with numerous slight changes in the geologic model.

Gibson South

Gibson South is located in Gibson County, Indiana at 38°18'22"N, 87°42'30"W and currently has approximately 23,350 underground acres permitted. The mine property is controlled through both fee ownership and leases of the coal. Gibson South holds rights to approximately 21,600 gross acres of coal. Leases generally have an initial term with automatic extensions for as long as mining operations are conducted within a described area. Local infrastructure is as follows:

Major Roads: Interstates 69 and 64,
Railroads: CSX and NS,
Airport: Evansville Regional Airport (EVV),
Town: Princeton,
Docks: Mount Vernon on the Ohio River,
Water: Gibson Water, Inc. and well water,
Electricity: Western Indiana Energy REMC,

Personnel: Regional.



Description

The underground mine is currently in production using room-and-pillar methods utilizing a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill mining and permitting requirements. The mine began production in 2014. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Total book value of the property and any associated plant and equipment for Gibson South as of December 31, 2021 was $118.8 million.

History

In November 1997, pursuant to (a) Assignment of Underground Coal Leases, (b) Partial Assignment of Underground Coal Leases and (c) Special Corporate Warranty Deed, Old Ben conveyed to MAPCO Land & Development Corporation various coal leases and fee coal interests within a large property boundary located in Gibson County, Indiana. MAPCO Land & Development Corporation changed its name to MAPCO Coal Land & Development Corporation, and MAPCO Coal Land & Development Corporation merged into Alliance Properties, LLC ("Alliance Properties") effective August 4, 1999.

Old Ben ran large exploration programs across multiple years to examine thickness, mineability, and quality, drilling a total of 137 holes. Another 73 holes were drilled in the western area of the property by owners of an adjacent mine.

After the original Old Ben acquisition, Alliance Properties and Gibson County Coal continued to acquire additional coal leases and fee coal interests in the area. In addition, beginning in or around 2006, the leases originally acquired from Old Ben began to expire by their terms, and Alliance Properties/Gibson County Coal began a program of either amending the expiring leases or entering into new, direct leases with the coal owners. Alliance Properties merged into Gibson County Coal on February 19, 2018.

Encumbrances

Our revolving credit facility is secured by, among other things, liens against certain Gibson County Coal surface properties, coal leases and owned coal. Documentation of such liens is of record in the Office of the Recorder of Gibson County, Indiana. Please read "Item 8. Financial Statements and Supplementary Data – Note 8 – Long-term Debt" for more information on our revolving credit facility.

Accounts receivable generated from the sale of coal mined from this property are collateral for our accounts receivable securitization facility, evidenced by financing statements of record in the Office of the Recorder of Gibson County, Indiana. Please read "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-term Debt" for more information on our accounts receivable securitization facility.

The Indiana Department of Natural Resources, Division of Reclamation is responsible for oversight of active coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations. In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining. All applicable permits for underground mining, coal preparation, and related facilities and other incidental activities have been obtained and remain in good standing.

Geology and Reserves

Gibson South extracts coal underground from the Springfield (Indiana No.5) seam at depths ranging from 450 to 650 feet. The table below summarizes mineral reserves as of 12/31/21 using a cut off thickness of 4.00 feet:

			Quality, Washed, Dry Basis				% Recovery	
Reserves	**Tons (millions)**	**Thickness (ft)**	**% Ash**	**% Sulfur**	**Btu**	**lbs. SO2**	**In-Seam**	**Prep Plant**
Gibson South								
Proven Mineral Reserves	44.2	6.10	6.97	1.92	13,506	2.84	95.05	74.87
Probable Mineral Reserves	8.4	5.46	7.91	2.33	13,349	3.49	93.39	72.12
Total Mineral Reserves	52.6	6.00	7.12	1.98	13,482	2.94	94.79	74.44

The Gibson South mine had 54.7 million tons of coal mineral reserves at the end of 2020. The year over year reconciliation is as follows:

Gibson South Yearly Reserve Reconciliation	**(millions)**
Tons as of December 31, 2020	54.7
Production	(3.3)
Mineral Acquisition / Deletion	0.9
Normal Course Adjustments	0.3
Tons as of December 31, 2021	52.6

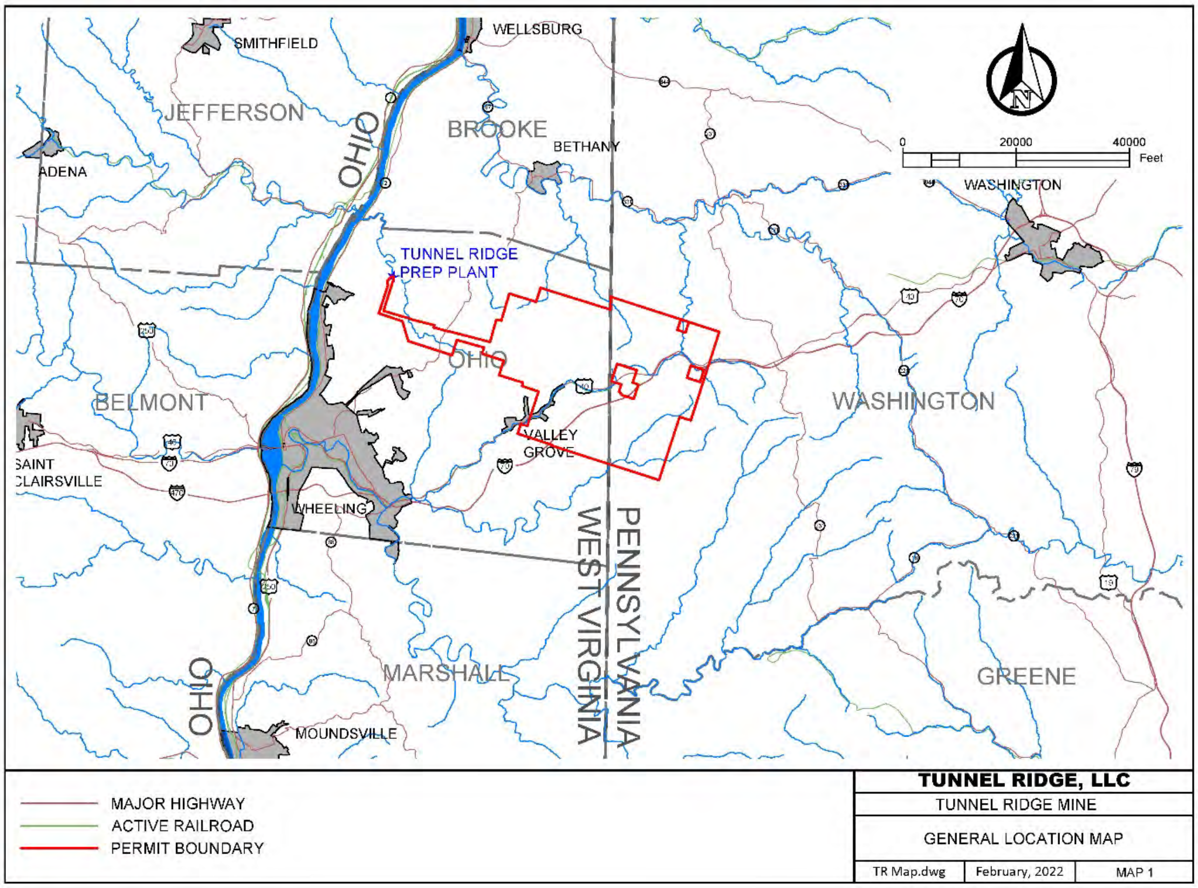
Normal course adjustments are associated with numerous slight changes in the geologic model.

Tunnel Ridge

Tunnel Ridge, located at 40°09’17" N, -80°39’26"W, is an underground longwall mine in the Pittsburgh No. 8 seam of coal, and currently has approximately 20,890 underground acres permitted. The mine property is controlled through both fee ownership and leases of the coal. The vast majority of the coal mined and to be mined by Tunnel Ridge is leased from the Joseph W. Craft III Foundation and the Kathleen S. Craft Foundation. Please read "Item 8. Financial Statements and Supplemental Data - Note 21 – Related Party Transactions" for additional information on this lease. Tunnel Ridge either owns or controls the surface properties upon which its facilities are located, including the preparation plant, refuse areas, mine offices, conveyor systems, shafts and slopes. Local infrastructure is as follows:

Major Roads: Interstate 70,
Railroads: None,
Airport: Pittsburgh International Airport (PIT),
Town: Wheeling,
Docks: Tunnel Ridge on the Ohio River,
Water: Ohio County Water District and mine sources,

Electricity: American Electric Power (AEP), West Penn Power (WPP)
Personnel: Regional.



Description

The underground mine is currently in production using longwall and room-and-pillar methods utilizing a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill mining and permitting requirements. The mine began production in 2010. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Total book value of the property and any associated plant and equipment for Tunnel Ridge as of December 31, 2021 was $238.8 million.

History

Valley Camp Coal Company ("Valley Camp") operated mines on the property prior to Tunnel Ridge's operations.

Valley Camp drilled 24 exploration holes in and adjacent to the reserve area to check thickness, quality, and mineability of the Pittsburgh No. 8 seam. Tunnel Ridge accounts for over 80 of the remaining holes. Also, Tunnel Ridge has collected over 600 channel samples to supplement the exploration drilling.

Encumbrances

Our revolving credit facility is secured by, among other things, liens against certain Tunnel Ridge surface properties, coal leases and owned coal. Documentation of such liens is of record in the Office of the County Commission of Ohio County, West Virginia and the Office of the Recorder of Deeds of Washington County, Pennsylvania. Please read "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-term Debt" for more information on our revolving credit facility.

Accounts receivable generated from the sale of coal mined from this property are collateral for our accounts receivable securitization facility, evidenced by financing statements of record in the Office of the County Commission of Ohio County, West Virginia and the Office of the Recorder of Deeds of Washington County, Pennsylvania. Please read "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-term Debt" for more information on our accounts receivable securitization facility.

Tunnel Ridge is located on the West Virginia / Pennsylvania State boundary, operating in each state. As such, regulatory requirements must be met pertaining to mining facilities located in each state.

For operations in West Virginia, the West Virginia Department of Environmental Protection ("WVDEP") is the regulatory authority over mining activities. Within the WVDEP, the Division of Mining and Reclamation is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations.

For operations in Pennsylvania, the Pennsylvania Department of Environmental Protection (PADEP) is the regulatory authority over mining activities. Within the PADEP, the Bureau of District Mining Operations is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations.

Geology and Reserves

Tunnel Ridge extracts coal underground from the Pittsburgh No.8 seam at depths ranging from 300 to 800 feet. The table below summarizes mineral reserves as of December 31, 2021 using a cut off thickness of 4.00 feet:

			Quality, Washed, Dry Basis				% Recovery	
Reserves	**Tons (millions)**	**Thickness (ft)**	**% Ash**	**% Sulfur**	**Btu**	**lbs. SO2**	**In-Seam**	**Prep Plant**
Tunnel Ridge								
Proven Mineral Reserves	28.6	6.89	8.12	3.32	13,685	4.86	69.21	51.90
Probable Mineral Reserves	25.1	7.02	8.23	3.47	13,650	5.09	67.87	52.69
Total Mineral Reserves	53.7	6.95	8.17	3.39	13,669	4.97	68.58	52.27

The Tunnel Ridge mine had 64.0 million tons of coal mineral reserves at the end of 2020. The year over year reconciliation is as follows:

Tunnel Ridge Yearly Reserve Reconciliation	**(millions)**
Tons as of December 31, 2020	64.0
Production	(7.2)
Mine Plan Adjustment	(3.1)
Tons as of December 31, 2021	53.7

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, 2021, we had approximately 42,000 developed and undeveloped net acres held at a weighted average royalty of 17.0%. Our net acres standardized to 1/8th royalty equates to approximately 57,000 net royalty acres, including approximately 3,976 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, 2021 based on the reserve report prepared by our internal engineering team. The reserve 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.

	As of December 31, 2021			
	Crude Oil (MBbl)	**Natural Gas (MMcf)**	**Natural Gas Liquids (MBbl)**	**Total (MBOE) (2)**
Estimated proved developed reserves	5,493	28,426	3,039	13,269
Estimated proved undeveloped reserves	1,353	4,126	578	2,618
Total estimated proved reserves (1)	6,846	32,552	3,617	15,887

(1) Proved reserves of approximately 1,285 MBOE were attributable to noncontrolling interests as of December 31, 2021.

(2) 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, 2021 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 2021. The average realized product prices weighted by production over the remaining lives of the properties are $63.57/Bbl for oil, $2.98/Mcf of natural gas and $21.13 per barrel of NGL. These prices are adjusted for energy content, associated average differential and transportation deducts by producing area to arrive at the net realized prices by product. For 2021, NGL prices averaged approximately 37% of the posted oil prices during the course of the year with an additional $3.49/Bbl deducted for transportation costs.

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

Beginning balance, January 1, 2021	4,533
Sales of PUDs	(12)
Transfers of PUDs to estimated proved developed	(1,469)
Extensions and discoveries	971
Revisions of previous estimates	(1,405)
Ending balance, December 31, 2021	2,618

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, 2021, we did not have any expenditures to convert PUDs to proved developed producing 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, 2021 approximately 16.48% 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.

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, 2021 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, our engineering team 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, and radioactivity logs.

Our 2021 year-end proved reserves were prepared by our internal engineering team. Our engineering team works to ensure the integrity, accuracy, and timeliness of the data used to calculate our estimated proved reserves. Approximately 95% of our total 2021 year end proved reserve estimates were audited by NSAI. Our engineering team met with NSAI periodically during the period covered by the above referenced reserve report to discuss the assumptions and methods used in the reserve estimation process. Our engineering team provided historical information to NSAI for our properties, such as oil & gas production, well test data, and realized commodity prices. Our engineering team also provided ownership interest information with respect to our properties. Our internal petroleum engineer, primarily responsible for overseeing the petroleum reserves preparation, has over 20 years of engineering and operations experience in the oil & gas sector and a Bachelor of Science in Petroleum Engineering.

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;
- verification of property ownership by our land department;
- 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;
- internally prepared reserve estimates compared to reserves audit by NSAI;
- review of changes in reserves semi-annually by our internal petroleum engineer and by senior management; and
- no employee's compensation is tied to the amount of reserves booked.

NSAI, an independent third-party petroleum engineering firm, does not own an interest in any of our properties and is not employed on a contingent basis. When compared on a well-by-well basis, some of our estimates are greater and some are less than the NSAI estimates. NSAI is satisfied with our methods and procedures used to prepare the December 31, 2021 reserve estimates and future revenue, and noted nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, prepared by us. NSAI's audit report with the respect to our proved reserve estimates as of December 31, 2021 is included as an exhibit to this Annual Report on Form 10-K.

NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Acreage Concentration

Our mineral interests, which include both proved reserves discussed above and unproved reserves, 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 mineral and net royalty acreage associated with our mineral interests in each of our primary basins as of December 31, 2021.

	Developed Acreage			Undeveloped Acreage		
	Gross	**Net Mineral**	**Net Royalty**	**Gross**	**Net Mineral**	**Net Royalty**
Basin						
Permian Basin	249,660	5,345	6,930	525,983	14,574	19,431
Anadarko Basin	142,311	5,106	7,282	294,826	10,905	15,538
Williston Basin	113,579	1,834	2,399	113,437	1,803	2,369
Other	27,885	863	1,086	37,821	1,525	1,887
Total	533,435	13,148	17,697	972,067	28,807	39,225

Oil & Gas Production Prices and Production Costs

For the year ended December 31, 2021, 46.8% of our production and 70.0% 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,		
	2021	**2020**	**2019**
Production:			
Oil (MBbls)	825	948	741
Natural gas (MMcf)	3,490	3,635	3,664
Natural gas liquids (MBbls)	357	337	364
BOE (MBbls)	1,764	1,892	1,716
Average Realized Prices:			
Oil (per Bbl)	$ 66.84	$ 39.04	$ 54.30
Natural gas (per Mcf)	$ 3.85	$ 1.52	$ 2.01
Natural gas liquids (per Bbl)	$ 28.51	$ 9.08	$ 20.17
BOE (MBbls)	$ 44.65	$ 24.10	$ 32.02
Unit cost per BOE:			
Production and ad valorem taxes	$ 4.46	$ 2.64	$ 4.82

Productive Wells

As of December 31, 2021, 6,572 gross productive horizontal wells and 4,167 gross productive vertical wells were located on the acreage in which we have a mineral interest. Of our productive horizontal wells, 965 are considered natural gas wells, while the remaining 5,607 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 22 – Commitments and Contingencies" is incorporated herein by this reference.

Litigation was initiated in November 2019 in the U.S. District Court for the Western District of Kentucky (Branson v. Webster County Coal, LLC et al.) against certain of our subsidiaries in which the plaintiffs allege violations of the Fair Labor Standards Act and Kentucky Wage and Hour Act due to alleged failure to compensate for time "donning" and "doffing" equipment and to account for certain bonuses in the calculation of overtime rates and pay. The plaintiffs seek class or collective action certification. A similar lawsuit was initiated in March 2020 in the U.S. District Court for the Eastern District of Kentucky (Brewer v. Alliance Coal, LLC, et al.). Collectively, the plaintiffs of these two lawsuits allege damages ranging from approximately $22.2 million to $143.7 million. Subsequently, four additional lawsuits making similar allegations were initiated against certain of our subsidiaries: filed March 4, 2021 in the Circuit Court for Hopkins County, Kentucky (Johnson v. Hopkins County Coal, LLC, et al.); filed April 6, 2021 in the U.S. District Court for the Northern District of West Virginia (Rettig v. Mettiki Coal WV, LLC, et al.); filed April 9, 2021 in the U.S. District Court for the Southern District of Illinois (Cates v. Hamilton County Coal, LLC, et al.); and filed April 13, 2021 in the U.S. District Court for the Southern District of Indiana (Prater v. Gibson County Coal, LLC, et al.). The plaintiffs in these cases seek to recover alleged compensatory, liquidated and/or exemplary damages for the alleged underpayment, and costs and fees that potentially may be recoverable under applicable law. We believe the claims made in these lawsuits are without merit and intend to defend the litigation vigorously. The litigation is in early stages. We do not believe this litigation will have a material adverse effect on our business, financial position or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (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 32,374 record holders of common units at December 31, 2021.

Available cash with respect to each quarter may, at the discretion of our general partner, be distributed to the limited partners as of a record date selected by the general partner. "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.

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.

During the three months ended December 31, 2021, we did not repurchase and retire any units. Since inception of the unit repurchase program, we have repurchased and retired 5,460,639 units at an average unit price of $17.12 for an aggregate purchase price of $93.5 million. The remaining authorized amount for unit repurchases under this program is $6.5 million.

ITEM 6. [Reserved]

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 operating and royalty income from the production and marketing of coal to major domestic and international utilities and industrial users as well as royalty 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 operating underground mining complexes in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia, as well as a coal-loading terminal in Indiana. In addition to our mining operations, Alliance Resource Properties owns or leases coal mineral reserves and resources in the Illinois and Appalachia Basins that are (a) leased to our internal mining complexes or (b) near other internal and external coal mining operations. The oil & gas 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, 2021, we had approximately 547.1 million tons of proven and probable coal mineral reserves and 1.17 billion tons of measured, indicated and inferred coal mineral resources in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. All of our measured, indicated and inferred coal mineral resources and 422.9 million tons of these coal mineral reserves are owned or leased by Alliance Resource Properties, our land holding company. We believe we control adequate reserves to implement our currently contemplated mining plans. Please see "Item 1. Business—Coal Mining Operations" in our Annual Report on Form 10-K for the year ended December 31, 2021 for further discussion of our mines.

In 2021, we sold 32.3 million tons of coal and produced 32.2 million tons. Of the 32.3 million tons sold, approximately two-thirds was leased from Alliance Resource Properties. The coal we sold in 2021 was approximately 14.2% low-sulfur coal, 50.3% medium-sulfur coal and 35.5% 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 11,450 to 13,200. In 2021, approximately 87.7% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices.

During 2021, approximately 81.6% of our tons sold were purchased by U.S. electric utilities and 12.5% were sold into the international markets through brokered transactions. The balance of tons sold were to third-party resellers and industrial consumers. Although some utility customers continue to favor a shorter-term contracting strategy, in 2021 we have continued to see several domestic utilities in the market seeking significant coal supply commitments for multi-year terms. Long-term sales contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2021, approximately 77.9% of our sales tonnage was sold under long-term sales contracts.

On October 13, 2021, AR Midland acquired approximately 1,480 oil & gas net royalty acres in the Delaware Basin from Boulders for a purchase price of $31.0 million in the Boulders Acquisition. This acquisition enhances our ownership position in the Permian Basin and furthers our business strategy to grow our Oil & Gas Royalties segment. Following the Boulders Acquisition, we hold approximately 57,000 net royalty acres in premier oil & gas basins including our investment in AllDale III. For more information, please read "Item 8. Financial Statement and Supplemental Data—Note 3 – Acquisitions" of this Annual Report on Form 10-K.

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 federal and state legislative and regulatory initiatives. Additionally, our results of operations could be impacted by our ability to obtain and renew permits necessary for our operations, secure or acquire coal mineral reserves and resources, 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. 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, which are mostly borne by our customers, may be substantial and are often the determining factor in a coal consumer's contracting decision. The principal expenses related to our oil & gas minerals interests business are production and ad valorem taxes. For our coal royalty interests business, the principal expenses are royalty expenses and production and ad valorem taxes.

Our primary business strategy is to create sustainable, capital-efficient growth in available cash to maximize unitholder returns by:

- expanding our operations by adding and developing mines and coal mineral reserves and resources in existing, adjacent or neighboring properties;
- extending the lives of our current mining operations through acquisition and development of coal mineral reserves and resources 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 in other industries inside and outside of the MLP sector; and
- continuing to make investments in oil & gas mineral interests and coal royalty interests in various geographic locations within producing basins in the continental United States.

As of December 31, 2021, we had four reportable segments: Illinois Basin Coal Operations, Appalachia Coal Operations, Oil & Gas Royalties and Coal Royalties. We also have an "all other" category referred to as Other, Corporate and Elimination. The two Coal Operations 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 Oil & Gas Royalties reportable segment includes our oil & gas mineral interests which are located primarily in the Permian (Delaware and Midland), Anadarko (SCOOP/STACK), and Williston (Bakken) basins. Our ownership in these basins includes approximately 57,000 net royalty acres, which provide us with diversified exposure to industry leading operators consistent with our general strategy to grow our oil & gas mineral interest business. We market our oil & gas mineral interests for lease to operators in those regions and generate royalty income from the leasing and development of those mineral interests. Our Coal Royalties reportable segment includes coal mineral reserves and resources owned or leased by Alliance Resource Properties, which are either a) leased to our mining complexes or (b) near our coal mining operations but not yet leased.

Beginning in the first quarter of 2021, we began to strategically view and manage our coal royalty activities separately from our coal operations since acquiring and managing a variety of royalty producing assets involve similar attributes. As a result, we restructured our reportable segments to better reflect this strategic view in how we manage our business and allocate resources. Periods prior to 2021 that are presented herein have been recast to include Alliance Resource Properties within our new Coal Royalties reportable segment with offsetting recast adjustments primarily to our coal operations reportable segments and to a lesser extent, our Other, Corporate and Elimination category. Eliminations reported in Other, Corporate and Elimination were also recast to reflect intercompany royalty revenues and offsetting intercompany royalty expense resulting from our new Coal Royalties reportable segment.

- *Illinois Basin Coal Operations* reportable segment includes currently operating mining complexes (a) the Gibson County Coal mining complex, which includes the Gibson South mine, (b) the Warrior mining complex, (c) the River View mining complex and (d) the Hamilton mining complex. The Illinois Basin Coal Operations reportable segment also includes our Mt. Vernon coal-loading terminal in Indiana which currently operates on the Ohio River.

  The Illinois Basin Coal Operations reportable segment also includes Mid-America Carbonates, LLC ("MAC") and other support services as well as non-operating mining complexes (a) Gibson North mine, which ceased production in the fourth quarter of 2019, (b) Webster County Coal's Dotiki mining complex, which ceased production in August 2019, (c) White County Coal, LLC's Pattiki mining complex, which ceased production in December 2016, (d) the Hopkins County Coal, LLC mining complex, which ceased production in April 2016, and (e) the Sebree mining complex, which ceased production in November 2015. The non-operating mining complexes are in various stages of reclamation.

- *Appalachia Coal Operations* reportable segment includes currently 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.

- *Oil & Gas Royalties* 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 and Cavalier Minerals. AR Midland acquired its mineral interests in the Wing Acquisition and Boulders Acquisition. Please read "Item 8. Financial Statements and Supplementary Data—Note 3 – Acquisitions" and "—Note 13 – Investments" of this Annual Report on Form 10-K for more information on the Wing Acquisition and Boulders Acquisition, and AllDale III, respectively.

- *Coal Royalties* reportable segment includes coal mineral reserves and resources owned or leased by Alliance Resource Properties that are (a) leased to certain of our mining complexes in both the Illinois Basin Coal Operations and Appalachia Coal Operations reportable segments or (b) located near our operations and external mining operations. Approximately two thirds of the coal sold by our Coal Operations' mines is leased from our Coal Royalties entities.

- *Other, Corporate and Elimination* includes marketing and administrative activities, the Matrix Group, Pontiki Coal, LLC's workers' compensation and pneumoconiosis liabilities, Wildcat Insurance, which assists the ARLP Partnership with its insurance requirements, AROP Funding, LLC ("AROP Funding") and Alliance Resource Finance Corporation ("Alliance Finance"). Please read "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-term Debt" of this Annual Report on Form 10-K for more information on AROP Funding and 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 sold; (4) price per BOE; (5) coal royalty tons sold; (6) coal royalty revenue per ton; (7) Segment Adjusted EBITDA Expense per ton; (8) EBITDA; and (9) 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.

Coal Royalty Tons sold. We monitor and analyze our coal royalty sales volumes from our various mining subsidiaries for coal leased by Alliance Resource Properties for consistency with our Coal Operations segments and for trend analysis.

Coal Royalty Revenue per Ton. We define coal royalty revenue per ton as total coal royalties divided by royalty tons sold. We review coal royalty revenue per ton to evaluate consistency with our Coal Operations segments 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 and goodwill impairments 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

2021 Compared with 2020

Total revenues increased 18.2% to $1.57 billion, compared to $1.33 billion for 2020 primarily due to increased coal sale volumes and oil & gas prices, which increased 14.4% and 88.2%, respectively. Higher revenues, lower depreciation and $157.0 million of non-cash impairment charges in 2020, partially offset by higher Segment Adjusted EBITDA Expense, resulted in net income attributable to ARLP of $178.2 million for 2021 compared to a net loss attributable to ARLP of $129.2 million for 2020. In general, results from coal operations and oil & gas royalties for 2021 were significantly improved compared to 2020, which was impacted by reduced global energy demand and weak commodity prices as a result of lockdown measures imposed in response to the COVID-19 pandemic.

	Year Ended December 31,		Year Ended December 31,	
	2021	2020	2021	2020
	(in thousands)		(per ton/BOE sold)	
Coal - Tons sold	32,268	28,212	N/A	N/A
Coal - Tons produced	32,207	26,990	N/A	N/A
Coal - Coal sales	$ 1,386,923	$ 1,232,272	$ 42.98	$ 43.68
Coal - Segment Adjusted EBITDA Expense (1) (2)	$ 975,839	$ 881,006	$ 30.24	$ 31.23
Oil & Gas Royalties - BOE sold	1,663	1,792	N/A	N/A
Oil & Gas Royalties - Royalties (3)	$ 74,988	$ 42,912	$ 45.08	$ 23.95
Coal Royalties - Tons sold	20,247	18,863	N/A	N/A
Coal Royalties - Intercompany royalties	$ 51,402	$ 42,112	$ 2.54	$ 2.23

(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 expenses of our Oil & Gas Royalties segment and is adjusted for intercompany transactions with our Coal Royalties segment.
(3) Average sales price per BOE is defined as oil & gas royalty revenues excluding lease bonus revenue divided by total BOE sold.

Coal sales. Coal sales increased $154.7 million or 12.6% to $1.39 billion for 2021 from $1.23 billion for 2020. The increase was attributable to a volume variance of $177.2 million resulting from increased tons sold partially offset by a negative price variance of $22.5 million due to lower average coal sales prices. Tons sold increased 14.4% to 32.3 million tons in 2021 due to improved coal demand and increased export shipments. Primarily due to the expiration of higher priced contract shipments, coal sales price realizations declined 1.6% in 2021 to $42.98 per ton sold, compared to $43.68 per ton sold during 2020. Production volumes increased by 19.3% in 2021, reflecting the temporary idling and scaling back of production at certain mines during 2020 in response to weak market conditions resulting from the pandemic.

Coal - Segment Adjusted EBITDA Expense. Segment Adjusted EBITDA Expense for our coal operations increased 10.8% to $975.8 million, as a result of higher coal sales volumes. On a per ton basis, Segment Adjusted EBITDA Expense for our coal operations decreased 3.2% in 2021 to $30.24 per ton sold, compared to $31.23 per ton in 2020, primarily due to increased volumes lowering fixed costs per ton, a favorable sales mix from our lower cost mines and the impact of ongoing expense control and efficiency initiatives at all of our mining operations in addition to other cost decreases which are discussed below by category:

- Labor and benefit expenses per ton produced, excluding workers' compensation, decreased 11.3% to $9.53 per ton in 2021 from $10.75 per ton in 2020. The decrease of $1.22 per ton was primarily due to increased volumes at our Illinois Basin mines where production was temporarily idled in 2020 in response to weak market conditions resulting from the pandemic.

- Workers' compensation expenses per ton produced decreased to $0.38 per ton in 2021 from $0.59 per ton in 2020. The decrease of $0.21 per ton produced resulted from increased production and refunds received in 2021 on assessments paid to the state of Kentucky in prior years, partially offset by unfavorable workers' compensation accrual adjustments in 2021 primarily due to unfavorable changes in claims development.

- Maintenance expenses per ton produced decreased 11.2% to $2.77 per ton in 2021 from $3.12 per ton in 2020. The decrease of $0.35 per ton produced was primarily due to increased production volumes.

Segment Adjusted EBITDA Expense decreases above were partially offset by the following increase:

- Material and supplies expenses per ton produced increased 4.9% to $10.50 per ton in 2021 from $10.01 per ton in 2020. The increase of $0.49 per ton produced primarily reflects increases of $0.79 per ton for roof support, $0.21 per ton for contract labor used in the mining process and $0.17 per ton in longwall subsidence expense primarily at our Tunnel Ridge operation, partially offset by decreases of $0.30 per ton for outside expenses used in the mining processes and $0.14 per ton for environmental and reclamation expenses other than longwall subsidence.

Oil & gas royalties. Oil & gas royalty revenues increased to $75.0 million in 2021 compared to $42.9 million for 2020. The increase of $32.1 million was primarily due to significantly higher sales price realizations per BOE.

General and administrative. General and administrative expenses for 2021 increased to $70.2 million compared to $59.8 million in 2020. The increase of $10.4 million was primarily due to higher incentive compensation expenses.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense decreased to $261.4 million for 2021 compared to $313.4 million for 2020 primarily as a result of increased mine life estimates for certain mines and reduced depreciation associated with a) coal inventory changes, b) certain mines closed prior to 2021 and c) lower BOE volumes.

Asset impairments. During 2020, we recorded $25.0 million of non-cash asset impairment charges due to sealing our idled Gibson North mine, resulting in its permanent closure, and a decrease in the fair value of certain mining equipment and greenfield coal mineral reserves and resources as a result of weakened coal market conditions. Please read "Item 8. Financial Statements and Supplementary Data—Note 4 – Long-Lived Asset Impairments."

Goodwill impairment. During 2020, we recorded a $132.0 million non-cash goodwill impairment charge associated with our Hamilton mine, primarily as the result of reduced expected production volumes due to weakened coal market conditions and low energy demand resulting in part from the COVID-19 pandemic. Please read "Item 8. Financial Statements and Supplementary Data— Note 5 – Goodwill Impairment."

Transportation revenues and expenses. Transportation revenues and expenses were $69.6 million and $21.1 million for 2021 and 2020, respectively. The increase of $48.5 million was primarily attributable to increased average third-party transportation rates in 2021 and increased coal shipments to international markets for which we arrange third-party transportation. Transportation revenues are recognized when title to the coal passes to the customer and recognized in an amount equal to the corresponding transportation expenses.

Segment Information. Our 2021 Segment Adjusted EBITDA increased $102.8 million, or 23.0%, to $549.3 million from 2020 Segment Adjusted EBITDA of $446.5 million. Segment Adjusted EBITDA, tons sold, coal sales, other revenues, Segment Adjusted EBITDA Expense, oil & gas royalties, BOE volume, coal royalties and coal royalties tons sold by segment are as follows:

	Year Ended December 31,		Increase (Decrease)	
	2021	2020		
	(in thousands)			
Segment Adjusted EBITDA				
Illinois Basin Coal Operations	$ 265,292	$ 213,876	$ 51,416	24.0 %
Appalachia Coal Operations	172,601	171,362	1,239	0.7 %
Oil & Gas Royalties	68,774	39,773	29,001	72.9 %
Coal Royalties	33,202	23,968	9,234	38.5 %
Other, Corporate and Elimination (2)	9,383	(2,490)	11,873	(1)
Total Segment Adjusted EBITDA (3)	$ 549,252	$ 446,489	$ 102,763	23.0 %
Coal - Tons sold				
Illinois Basin Coal Operations	22,264	19,113	3,151	16.5 %
Appalachia Coal Operations	10,004	9,099	905	9.9 %
Total tons sold	32,268	28,212	4,056	14.4 %
Coal sales				
Illinois Basin Coal Operations	$ 873,930	$ 755,208	$ 118,722	15.7 %
Appalachia Coal Operations	512,993	477,064	35,929	7.5 %
Total coal sales	$ 1,386,923	$ 1,232,272	$ 154,651	12.6 %
Other revenues				
Illinois Basin Coal Operations	$ 4,666	$ 1,932	$ 2,734	141.5 %
Appalachia Coal Operations	3,940	14,954	(11,014)	(73.7)%
Oil & Gas Royalties	2,197	229	1,968	(1)
Coal Royalties	69	105	(36)	(34.3)%
Other, Corporate and Elimination	27,586	14,596	12,990	89.0 %
Total other revenues	$ 38,458	$ 31,816	$ 6,642	20.9 %
Segment Adjusted EBITDA Expense				
Illinois Basin Coal Operations	$ 613,303	$ 543,264	$ 70,039	12.9 %
Appalachia Coal Operations	344,332	320,656	23,676	7.4 %
Oil & Gas Royalties	9,943	4,106	5,837	142.2 %
Coal Royalties	18,269	18,249	20	0.1 %
Other, Corporate and Elimination (2)	(33,198)	(25,026)	(8,172)	(32.7)%
Total Segment Adjusted EBITDA Expense	$ 952,649	$ 861,249	$ 91,400	10.6 %
Oil & Gas Royalties				
Volume - BOE (4)	1,663	1,792	(129)	(7.2)%
Oil & gas royalties	$ 74,988	$ 42,912	$ 32,076	74.7 %
Coal Royalties				
Volume - Tons sold (5)	$ 20,247	18,863	$ 1,384	7.3 %
Intercompany coal royalties	51,402	$ 42,112	9,290	22.1 %

(1) Percentage change not meaningful.

(2) Other, Corporate and Elimination includes the elimination of intercompany coal royalty revenues and expenses between our Coal Royalties Segment and our Coal Operations Segments in addition to the expenses for the other miscellaneous activities included in this category.

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

(4) BOE for natural gas is calculated on a 6:1 basis (6,000 cubic feet of natural gas to one barrel).

(5) Represents tons sold by our Coal Operations Segments associated with coal mineral reserves leased from our Coal Royalties Segment.

Illinois Basin Coal Operations – Segment Adjusted EBITDA increased 24.0% to $265.3 million in 2021 from $213.9 million in 2020. The increase of $51.4 million was primarily attributable to higher coal sales, which increased 15.7% to $873.9 million in 2021 from $755.2 million in 2020. The increase of $118.7 million in coal sales primarily reflects increased sales volumes, which rose 16.5% compared to 2020 due to improved coal demand and increased export volumes reflecting the continued economic recovery from the COVID-19 pandemic. Increased expenses resulting from higher coal sales volumes, partially offset by ongoing cost control and efficiency initiatives, contributed to higher Segment Adjusted EBITDA Expense of $613.3 million in 2021 compared to $543.3 million in 2020. Segment Adjusted EBITDA Expense per ton decreased 3.1% to $27.55 from $28.42 per ton sold in 2020 primarily as a result of increased volumes where production was temporarily idled and scaled back in 2020 in response to weak market conditions resulting from the pandemic. A favorable sales mix from our lower cost mines in 2021 and the impact of ongoing expense control and efficiency initiatives at all of our mining operations in the region also contributed to the decrease. In addition, also see certain cost variances described above under "–Coal - Segment Adjusted EBITDA Expense."

Appalachia Coal Operations – Segment Adjusted EBITDA increased to $172.6 million for 2021 from $171.4 million in 2020. The increase of $1.2 million was primarily attributable to higher coal sales, partially offset by lower contract buy-out revenues during 2021. Coal sales increased 7.5% to $513.0 million in 2021 compared to $477.1 million in 2020 as a result of increased sales volumes, partially offset by lower price realizations. Tons sold increased 9.9% in 2021 compared to 2020 due to increased sales volumes at our Tunnel Ridge and MC Mining operations resulting from improved market conditions. Coal sales price per ton sold in 2021 decreased 2.2% compared to 2020 primarily due to the expiration of higher priced contract shipments. Segment Adjusted EBITDA Expense increased 7.4% in 2021 compared to 2020 due to increased coal sales volumes, partially offset by decreased per ton costs. Segment Adjusted EBITDA Expense per ton decreased 2.3% to $34.42 compared to $35.24 per ton sold in 2020, as a result of increased sales volumes lowering fixed costs per ton, the full-year production benefit from MC Mining's transition of mining operations to a new reserve area in the second half of 2020, ongoing expense control and efficiency initiatives and improved recoveries across the region. See also certain cost variances described above under "–Coal - Segment Adjusted EBITDA Expense."

Oil & Gas Royalties – Segment Adjusted EBITDA increased 72.9% to $68.8 million for 2021 from $39.8 million in 2020. The increase of $29.0 million was primarily due to significantly higher sales price realizations per BOE, which more than offset lower volumes.

Coal Royalties – Segment Adjusted EBITDA increased 38.5% to $33.2 million for 2021 from $24.0 million in 2020. The increase of $9.2 million was a result of increased royalty tons sold and higher average coal royalty revenue per ton received from our mining subsidiaries.

Other, Corporate and Elimination – Segment Adjusted EBITDA increased by $11.9 million in 2021 due primarily to increased mining technology product sales from the Matrix Group.

2020 Compared with 2019

Total revenues decreased 32.3% to $1.33 billion for 2020 compared to $1.96 billion for 2019 primarily due to lower coal sales and transportation revenues resulting from weak market conditions and disruptions caused by the COVID-19 pandemic. These lower revenues and a non-cash goodwill impairment charge of $132.0 million partially offset by lower operating expenses, resulted in a net loss attributable to ARLP of $129.2 million for 2020 compared to net income attributable to ARLP of $399.4 million for 2019, which included a net gain of $170.0 million related to the AllDale Acquisition in 2019. Operating expenses and transportation expenses totaled $859.7 million and $21.1 million, respectively, for 2020 compared to $1.18 billion and $99.5 million, respectively, in 2019.

	Year Ended December 31,		Year Ended December 31,	
	2020	2019	2020	2019
	(in thousands)		(per ton sold)	
Coal - Tons sold	28,212	39,289	N/A	N/A
Coal - Tons produced	26,990	39,981	N/A	N/A
Coal - Coal sales	$ 1,232,272	$ 1,762,442	$ 43.68	$ 44.86
Coal - Segment Adjusted EBITDA Expense (1) (2)	$ 881,006	$ 1,233,377	$ 31.23	$ 31.39
Oil & Gas Royalties - BOE sold	1,792	1,611	N/A	N/A
Oil & Gas Royalties - Royalties (3)	42,912	$ 51,735	$ 23.95	$ 32.12
Coal Royalties - Tons sold	18,863	23,002	N/A	N/A
Coal Royalties - Intercompany royalties	42,112	$ 57,737	$ 2.23	$ 2.51

(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 expenses of our Oil & Gas Royalties segment and is adjusted for intercompany transactions with our Coal Royalties segment.
(3) Average sales price per BOE is defined as oil & gas royalty revenues excluding lease bonus revenue divided by total BOE sold.

Coal sales. Coal sales decreased $530.2 million or 30.1% to $1.23 billion for 2020 from $1.76 billion for 2019. The decrease was attributable to a volume variance of $496.9 million resulting from decreased tons sold and a price variance of $33.3 million due to lower average coal sales prices. Tons sold declined 28.2% to 28.2 million tons in 2020, due to reduced shipments to domestic utilities and international markets. Coal sales price realizations declined 2.6% in 2020 to $43.68 per ton sold, compared to $44.86 per ton sold during 2019 resulting, in part, from the absence of high priced metallurgic coal volumes in the 2020 Year. Coal production volumes fell to 27.0 million tons, a reduction of 32.5% compared to 2019, due to temporarily idling production at certain mines particularly in the Illinois Basin Coal Operations region, in response to weak market conditions during 2020.

Coal - Segment Adjusted EBITDA Expense. Segment Adjusted EBITDA Expense for our coal operations decreased 28.6% to $881.0 million in 2020, primarily as a result of reduced tons sold. Segment Adjusted EBITDA Expense per ton decreased slightly in 2020 to $31.23 per ton, compared to $31.39 per ton in 2019. The decrease is attributed primarily to expense control initiatives at all operations, partially offset by the per ton cost impact of lower coal volumes resulting from production curtailment in response to market conditions. Significant cost control initiatives included the closure of higher cost per ton production at our Dotiki and Gibson North mines. Cost per ton in 2020 also benefited from improved recoveries at several mines in both regions offset in part by reduced unit shifts from the curtailment. Our costs per ton were impacted by the following cost variances as discussed by category:

- Material and supplies expenses per ton produced decreased 8.6% to $10.01 per ton in 2020 from $10.95 per ton in 2019. The decrease of $0.94 per ton produced resulted primarily from production mix benefits and improved recoveries previously mentioned, related decreases of $0.46 per ton for roof support, $0.32 per ton for contract labor used in the mining process and $0.14 per ton for certain ventilation expenses, partially offset by an increase of $0.15 per ton for power and fuel used in the mining process.

- Maintenance expenses per ton produced decreased 13.1% to $3.12 per ton in 2020 from $3.59 per ton in 2019. The decrease of $0.47 per ton produced was primarily due to reduced maintenance requirements as a result of production mix benefits and improved recoveries previously mentioned.

- We had no sales of outside coal purchases in 2020 compared to $23.4 million in 2019. Thus, costs per ton in 2020 benefited as our cost of outside coal purchases are generally higher on a per ton basis than our produced coal.

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

- Labor and benefit expenses per ton produced, excluding workers' compensation, increased 8.7% to $10.75 per ton in 2020 from $9.89 per ton in 2019. The increase of $0.86 per ton was primarily due to curtailed production, partially offset by an improved production mix and improved recoveries at certain mines all previously discussed.

- Production taxes and royalty expenses per ton incurred as a percentage of coal sales prices and volumes increased $0.53 per produced ton sold in 2020 compared to 2019 primarily as a result of a $0.60 per ton government-imposed increase in the federal black lung excise tax, effective January 1, 2020 and an unfavorable state production mix increasing severance taxes per ton, in addition to increased excise taxes per ton resulting from a greater mix of domestic vs. export shipments in 2020 compared to 2019.

Oil & gas royalties. Oil & gas royalty revenues decreased to $42.9 million in 2020 compared to $51.7 million for 2019. The decrease was primarily due to lower average product prices, partially offset by higher volumes resulting from the Wing Acquisition in August 2019 and continued drilling and development of our mineral interests.

Other revenues. Other revenues were principally comprised of Mt. Vernon transloading revenues in our Illinois Basin Coal Operations segment, oil & gas lease bonuses in our Oil & Gas Royalties segment and Matrix Design sales in Other, Corporate and Elimination. Other revenues also include contract buy-out revenues and other outside services which could occur in any of our segments. Other revenues decreased to $31.8 million in 2020 from $48.0 million in 2019. The decrease of $16.2 million was primarily due to reduced sales of mining technology products by our Matrix Design subsidiary and lower coal volumes shipped through our Mt. Vernon transloading facility.

General and administrative. General and administrative expenses for 2020 decreased to $59.8 million compared to $73.0 million in 2019. The decrease of $13.2 million was primarily due to incentive compensation reductions and our expense reduction initiatives.

Asset impairments. During 2020, we recorded $25.0 million of non-cash asset impairment charges due to sealing our idled Gibson North mine, resulting in its permanent closure, and a decrease in the fair value of certain mining equipment and greenfield coal mineral reserves and resources as a result of weakened coal market conditions. During 2019, we recorded an asset impairment charge of $15.2 million due to the cessation of production at our Dotiki mine. Please read "Item 8. Financial Statements and Supplementary Data—Note 4 – Long-Lived Asset Impairments" of this Annual Report on Form 10-K."

Goodwill impairment. During 2020, we recorded a $132.0 million non-cash goodwill impairment charge associated with our Hamilton mine, primarily as the result of reduced expected production volumes due to weakened coal market conditions and low energy demand resulting in part from the COVID-19 pandemic. Please read "Item 8. Financial Statements and Supplementary Data— Note 5 – Goodwill Impairment " of this Annual Report on Form 10-K.

Equity securities income. Equity securities income decreased $12.9 million compared to 2019 as we did not recognize equity securities income in 2020 due to the redemption of our preferred interest in Kodiak Gas Service, LLC ("Kodiak") in 2019.

Acquisition gain. We recorded a non-cash acquisition gain of $177.0 million in 2019 associated with the AllDale Acquisition to reflect the fair value of the interests in AllDale I & II we already owned at the time of the acquisition.

Transportation revenues and expenses. Transportation revenues and expenses were $21.1 million and $99.5 million for 2020 and 2019, respectively. The decrease of $78.4 million was largely attributable to decreased coal tonnage for which we arrange third-party transportation at certain mines primarily reflecting reduced coal shipments to international markets and a decrease in average third-party transportation rates in 2020. 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 decreased to $0.2 million in 2020 from $7.5 million in 2019 as a result of allocating $7.1 million of the acquisition gain discussed above to noncontrolling interest in 2019.

Segment Information. Our 2020 Segment Adjusted EBITDA decreased $225.5 million, or 33.6%, to $446.5 million from 2019 Segment Adjusted EBITDA of $672.0 million. Segment Adjusted EBITDA, tons sold, coal sales, other revenues, Segment Adjusted EBITDA Expense, oil & gas royalties, BOE volume, coal royalties and coal royalties tons sold by segment are as follows:

	Year Ended December 31,			
	2020	2019	Increase (Decrease)	
		(in thousands)		
Segment Adjusted EBITDA				
Illinois Basin Coal Operations	$ 213,876	$ 349,810	$ (135,934)	(38.9)%
Appalachia Coal Operations	171,362	215,187	(43,825)	(20.4)%
Oil & Gas Royalties	39,773	46,997	(7,224)	(15.4)%
Coal Royalties	23,968	36,315	(12,347)	(34.0)%
Other, Corporate and Elimination (2)	(2,490)	23,692	(26,182)	(110.5)%
Total Segment Adjusted EBITDA (3)	$ 446,489	$ 672,001	$ (225,512)	(33.6)%
Coal - Tons sold				
Illinois Basin Coal Operations	19,113	28,480	(9,367)	(32.9)%
Appalachia Coal Operations	9,099	10,809	(1,710)	(15.8)%
Total tons sold	28,212	39,289	(11,077)	(28.2)%
Coal sales				
Illinois Basin Coal Operations	$ 755,208	$ 1,128,588	$ (373,380)	(33.1)%
Appalachia Coal Operations	477,064	628,406	(151,342)	(24.1)%
Other, Corporate and Elimination	—	5,448	(5,448)	(100.0)%
Total coal sales	$ 1,232,272	$ 1,762,442	$ (530,170)	(30.1)%
Other revenues				
Illinois Basin Coal Operations	$ 1,932	$ 13,017	$ (11,085)	(85.2)%
Appalachia Coal Operations	14,954	11,166	3,788	33.9 %
Oil & Gas Royalties	229	1,301	(1,072)	(82.4)%
Coal Royalties	105	23	82	(1)
Other, Corporate and Elimination	14,596	22,533	(7,937)	(35.2)%
Total other revenues	$ 31,816	$ 48,040	$ (16,224)	(33.8)%
Segment Adjusted EBITDA Expense				
Illinois Basin Coal Operations	$ 543,264	$ 791,795	$ (248,531)	(31.4)%
Appalachia Coal Operations	320,656	424,387	(103,731)	(24.4)%
Oil & Gas Royalties	4,106	7,811	(3,705)	(47.4)%
Coal Royalties	18,249	21,445	(3,196)	(14.9)%
Other, Corporate and Elimination (2)	(25,026)	(40,542)	15,516	38.3 %
Total Segment Adjusted EBITDA Expense	$ 861,249	$ 1,204,896	$ (343,647)	(28.5)%
Oil & Gas Royalties				
Volume - BOE (4)	1,792	1,611	181	11.2 %
Oil & gas royalties	$ 42,912	$ 51,735	$ (8,823)	(17.1)%
Coal Royalties				
Volume - Tons sold (5)	18,863	23,002	(4,139)	(18.0)%
Intercompany coal royalties	$ 42,112	$ 57,737	$ (15,625)	(27.1)%

(1) Percentage change not meaningful.

(2) Other, Corporate and Elimination includes the elimination of intercompany coal royalty revenues and expenses between our Coal Royalties Segment and our Coal Operations Segments in addition to the expenses for the other miscellaneous activities included in this category.

(3) For a definition of Segment Adjusted EBITDA and related reconciliation to comparable GAAP financial measures, please see below under "—Reconciliation of non-GAAP "Segment Adjusted EBITDA" to GAAP "net income (loss)."
(4) BOE for natural gas is calculated on a 6:1 basis (6,000 cubic feet of natural gas to one barrel).
(5) Represents tons sold by our Coal Operations Segments associated with coal mineral reserves leased from our Coal Royalties Segment.

Illinois Basin Coal Operations – Segment Adjusted EBITDA decreased 38.9% to $213.9 million in 2020 from $349.8 million in 2019. The decrease of $135.9 million was primarily attributable to lower coal sales, which decreased 33.1% to $755.2 million in 2020 from $1.13 billion in 2019, partially offset by reduced operating expenses. The decrease of $373.4 million in coal sales primarily reflects reduced tons sold, which decreased 32.9% compared to 2019 due to curtailed production across all of our mining operations in the region as a result of weak coal market conditions, particularly international markets, amid the COVID-19 pandemic. Segment Adjusted EBITDA Expense decreased 31.4% to $543.3 million in 2020 from $791.8 million in 2019 primarily as a result of reduced tons sold. Segment Adjusted EBITDA Expense per ton increased $0.62 per ton sold to $28.42 from $27.80 per ton sold in 2019, primarily due to reduced coal volumes and related increased fixed costs per ton offset in part by the closure of higher cost per ton operations, improved recoveries at certain mines in 2020 and reduced reclamation accruals at certain non-operating mines. In addition, see certain cost per ton and production variances described above under "–Coal - Segment Adjusted EBITDA Expense."

Appalachia Coal Operations – Segment Adjusted EBITDA decreased 20.4% to $171.4 million for 2020 from $215.2 million in 2019. The decrease of $43.8 million was primarily attributable to lower coal sales, which decreased 24.1% to $477.1 million in 2020 from $628.4 million in 2019, partially offset by reduced operating expenses. The decrease of $151.3 million in coal sales reflects lower tons sold and price realizations. Sales volumes decreased 15.8% in 2020 compared to 2019 due to curtailed production in the region as a result of weak coal market conditions, particularly international markets, amid the COVID-19 pandemic. Coal sales price per ton sold in 2020 decreased 9.8% compared to 2019 primarily due to reduced metallurgical tons sold and price realizations at our Mettiki mine. Segment Adjusted EBITDA Expense decreased 24.4% to $320.7 million in 2020 from $424.4 million in 2019 due to reduced tons sold and decreased per ton costs. Segment Adjusted EBITDA Expense per ton decreased $4.02 per ton sold to $35.24 compared to $39.26 per ton sold in 2019. The lower per ton expense in 2020 resulted primarily from fewer longwall move days and improved recoveries at both our Tunnel Ridge and Mettiki mines, reduced roof support expenses per ton and the absence of higher cost purchased tons sold in 2020, partially offset by curtailed production in the region during 2020 increasing fixed costs per ton. See also certain cost variances described above under "–Coal - Segment Adjusted EBITDA Expense."

Oil & Gas Royalties – Segment Adjusted EBITDA decreased to $39.8 million for 2020 from $47.0 million in 2019 reflecting reduced average sales price per BOE due to reduced demand amid the COVID-19 pandemic, partially offset by increased production volumes from the additional mineral interests acquired in the Wing Acquisition in August 2019 and from continued drilling and development activities.

Coal Royalties – Segment Adjusted EBITDA decreased 34.0% to $24.0 million for 2020 from $36.3 million in 2019. The decrease of $12.3 million was a result of reduced royalty tons sold and lower average coal royalty revenue per ton received from our mining subsidiaries.

Other, Corporate and Elimination – Segment Adjusted EBITDA decreased by $26.2 million in 2020 compared to 2019 due primarily to lower equity securities income as a result of the redemption of our preferred interest in Kodiak in 2019, decreased coal brokerage activity and lower mining technology product sales from the Matrix Group.

Reconciliation of non-GAAP "Segment Adjusted EBITDA" to GAAP "net income (loss)" 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 (loss) attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization, asset and goodwill impairments, acquisition gain 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 (loss), the most comparable GAAP financial measure:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Consolidated Segment Adjusted EBITDA	$ 549,252	$ 446,489	$ 672,001
General and administrative	(70,160)	(59,806)	(72,997)
Depreciation, depletion and amortization	(261,377)	(313,387)	(309,075)
Asset impairments	—	(24,977)	(15,190)
Goodwill impairment	—	(132,026)	—
Interest expense, net	(39,141)	(45,478)	(45,496)
Acquisition gain	—	—	177,043
Income tax (expense) benefit	(417)	(35)	211
Acquisition gain attributable to noncontrolling interest	—	—	(7,083)
Net income (loss) attributable to ARLP	$ 178,157	$ (129,220)	$ 399,414
Noncontrolling interest	598	169	7,512
Net income (loss)	$ 178,755	$ (129,051)	$ 406,926

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,		
	2021	2020	2019
		(in thousands)	
Segment Adjusted EBITDA Expense	$ 952,649	$ 861,249	$ 1,204,896
Outside coal purchases	(6,372)	—	(23,357)
Other income (expense)	(3,020)	(1,593)	561
Operating expenses (excluding depreciation, depletion and amortization)	$ 943,257	$ 859,656	$ 1,182,100

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, contractual obligations 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, contractual obligations, commitments and distribution payments. Nevertheless, our ability to satisfy our working capital requirements, to satisfy our contractual obligations, 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, including the COVID-19 pandemic. Based on our recent operating cash flow results, current cash position, anticipated future cash flows and sources of financing that we expect to have available, we anticipate remaining in compliance with the covenants of the Credit Agreement and expect to have sufficient liquidity to fund our operations and growth strategies. However, to the extent operating cash flow or access to and cost of financing sources are materially different than expected, future covenant compliance or liquidity may be adversely affected. Please see "Item 1A. Risk Factors."

On October 13, 2021, AR Midland acquired approximately 1,480 oil & gas net royalty acres in the Delaware Basin from Boulders for a purchase price of $31.0 million in the Boulders Acquisition. This acquisition enhances our ownership position in the Permian Basin and furthers our business strategy to grow our Oil & Gas Royalties segment through accretive acquisitions. Following the Boulders Acquisition, we hold approximately 57,000 net royalty acres in premier oil & gas basins including our investment in AllDale III. For more information, please read "Item 8. Financial Statement and Supplemental Data—Note 3 – Acquisitions".

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, 2021, we have purchased units for a total of $93.5 million under the program. During the year ended December 31, 2021, we did not repurchase and retire any units. Please read "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.

Cash Flows

Cash provided by operating activities was $425.2 million for 2021 compared to $400.6 million for 2020. The increase in cash provided by operating activities was primarily due to an increase in net income adjusted for non-cash items and favorable working capital changes primarily related to accounts payable and accrued payroll and related benefits, partially offset by unfavorable working capital changes related trade receivables, inventories and accrued taxes other than income taxes.

Net cash used in investing activities was $142.7 million for 2021 compared to $125.1 million for 2020. The increase in cash used in investing activities was primarily attributable Boulders Acquisition in 2021, partially offset by an increase in accounts payable and certain other accruals related to mine infrastructure, equipment and mining operations at various mines during 2021.

Net cash used in financing activities was $215.7 million for 2021 compared to $256.4 million for 2020. The decrease in cash used in financing activities was primarily attributable to reduced borrowings and payments on the revolving credit facility and reduced debt issuance costs in 2021, partially offset by increased payments and reduced borrowings on the securitization facility compared to 2020.

Cash Requirements

We currently estimate our 2022 annual cash requirements, including capital expenditures, scheduled payments on long-term debt, lease obligations, asset retirement obligation costs and workers' compensation and pneumoconiosis, to be in a range of $380.0 million to $400.0 million. Management anticipates having sufficient cash flow to meet 2022 cash requirements with our December 31, 2021 cash and cash equivalents of $122.4 million and cash flows from operations, or borrowings under revolving credit and securitization facilities if necessary. We currently project average estimated annual maintenance capital expenditures over the next five years of approximately $5.41 per ton produced. For additional information on our future cash requirements other than capital expenditures, please see "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-Term Debt," "—Note 9 – Leases," "—Note 16 – Employee Benefit Plans," "—Note 19 – Asset Retirement Obligations," "—Note 20 – Accrued Workers' Compensation and Pneumoconiosis Benefits" and "—Note 22 – Commitments and Contingencies." We will continue to have significant cash 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.

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, 2021:

	Reclamation Obligation	Workers' Compensation Obligation	Other	Total
		(in millions)		
Surety bonds	$ 173.9	$ 68.0	$ 12.6	$ 254.5
Letters of credit	—	32.3	16.8	49.1

Insurance

Effective December 1, 2021, 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 75- or 90-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, the insurance industry has been subject to efforts by environmental activists to restrict coverages available for fossil-fuel companies.

Debt Obligations

See "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-Term Debt" for a discussion of our debt obligations.

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 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 acquisitions in the Permian Basin to determine a market price for similar mineral interests.

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. Goodwill is not amortized, but subject to annual reviews on November 30th for impairment at the reporting unit level. Goodwill is assessed for impairment more frequently if events or changes in circumstances indicate that it is more likely than not that goodwill is 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.

The Partnership computes the fair value of its 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.

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 are required to make significant judgments and estimates regarding the impact of anticipated economic factors on our business. The forecast assumptions used in our assessments 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.

During the first quarter of 2020, we considered whether an interim test of our consolidated goodwill of $136.4 million was necessary. Our consolidated goodwill included $132.0 million recorded in conjunction with our acquisition of the Hamilton mine on July 31, 2015. We assessed certain events and changes in circumstances, including a) adverse industry and market developments, including the impact of the COVID-19 pandemic, b) our response to these developments, including temporarily ceasing production at several mines, including our Hamilton mine and c) our actual performance during the quarter. After consideration of these events and changes in circumstances, we performed an interim test of the goodwill associated with Hamilton comparing Hamilton's carrying amount to its fair value.

We estimated the fair value of Hamilton using a discounted cash flow model. The assumptions used in the discounted cash flow model considered market conditions at the time of the assessment and our estimate of the mine's performance in future years based on the information available to us. The fair value of Hamilton was determined to be below its carrying amount (including goodwill) by more than the recorded balance of goodwill associated with the mine. Accordingly, we recognized an impairment charge of $132.0 million consisting of the total carrying amount of goodwill associated with Hamilton. This impairment charge reduced our consolidated goodwill balance to $4.4 million. During the first quarter of 2020, we also performed tests on our goodwill balance associated with MAC using a discounted cash flow model and concluded no impairment was necessary. There were no impairments of goodwill during 2021 or 2019.

Our estimates of fair value are sensitive to changes in 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. See "Item 8. Financial Statements and Supplementary Data—Note 5 – Goodwill Impairment."

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 audited 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 reserve 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.

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 20 – Accrued Workers' Compensation and Pneumoconiosis Benefits" for additional discussion. We had accrued liabilities for workers' compensation of $53.4 million and $54.7 million for these costs at December 31, 2021 and 2020, respectively. A one-percentage-point reduction in the discount rate would have increased operating expense by approximately $4.1 million at December 31, 2021. 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, 2021 and 2020 are $5.7 million and $7.1 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 $111.3 million and $108.5 million for the pneumoconiosis benefits at December 31, 2021 and 2020, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2021 by approximately $3.0 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 Financial Times Stock Exchange 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, we compare our estimate of undiscounted future cash flows attributable to the asset to the carrying value of the asset. 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. Assumptions about sales, operating margins, capital expenditures and sales prices are based on our budgets, business plans, economic projections, and anticipated future cash flows. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, 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 $25.0 million and $15.2 million 2020 and 2019, respectively. There were no asset impairments during 2021. 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 $131.1 million and $127.9 million for these costs are recorded at December 31, 2021 and 2020, respectively. See "Item 8. Financial Statements and Supplementary Data—Note 19 – Asset Retirement Obligations" for additional information. The liability for asset retirement and closing procedures is sensitive to changes in cost estimates, estimated mine lives and timing of post-mine reclamation activities. 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. There were no material adjustments to the liability associated with these assumptions for the year ended December 31, 2021. Adjustments to the liability associated with these assumptions resulted in a decrease of $11.9 million for the year ended December 31, 2020.

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 $98.3 million and $102.1 million at December 31, 2021 and 2020. We estimate that the aggregate undiscounted cost of final mine closure is approximately $229.4 million and $230.0 million at December 31, 2021 and 2020, 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.

Shelf Registration Statement

In February 2018, we filed with the SEC a universal shelf registration statement which allowed us to issue from time to time an indeterminate amount of debt or equity securities ("2018 Registration Statement"). The 2018 Registration Statement expired in February 2021. We did not utilize any amounts available under the 2018 Registration Statement. We currently intend to file with the SEC a new universal shelf registration statement.

Related–Party Transactions

See "Item 8. Financial Statements and Supplementary Data—Note 21 – 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 $318.9 million and $321.3 million at December 31, 2021 and 2020, 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 19 – Asset Retirement Obligations" and "—Note 20 – 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 sales contracts as evidenced by approximately 77.9% of our sales tonnage being sold under long-term sales contracts in 2021. Most of the long-term sales 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. 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 23 – Concentration of Credit Risk and Major Customers." As of February 11, 2022, our nominal commitment under contract was approximately 33.1 million tons in 2022.

Our results of operations are highly dependent upon the prices we receive for our coal, oil and natural gas. Regarding coal, the short-term sales contracts favored by some of our coal customers leave us more exposed to risks of declining coal price periods. Also, a significant decline in oil & gas prices would have a significant impact on our oil & gas royalty revenues. We experienced this during 2020 as lower sales price realizations, caused by lower global energy demand during the COVID-19 pandemic and actions of major oil producing countries, had a significant impact on our royalty revenues. Please see discussions above, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for more information regarding the impact of the COVID-19 pandemic on our operations.

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 but may do so in the future.

Credit Risk

In 2021, approximately 81.6% of our tons sold were purchased by U.S. electric utilities and 12.5% 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. Such credit risks from customers may impact the borrowing capacity of our Securitization Facility. See "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-Term Debt" for more information on our Securitization Facility.

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 on any amounts drawn under these facilities. 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 did not have an outstanding balance on either the Revolving Credit Facility or the Securitization Facility at December 31, 2021. With respect to our fixed-rate borrowings, we had $400.0 million in borrowings under our Senior Notes and $43.1 million in borrowings under our equipment financings at December 31, 2021. A one percentage point increase in interest rates would result in a decrease of approximately $13.6 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, 2021 and 2020.

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

Expected Maturity Dates as of December 31, 2021	2022	2023	2024	2025	2026	Total	Fair Value December 31, 2021
				(dollars in thousands)			
Fixed rate debt	$ 16,071	$ 24,970	$ 2,039	$ 400,000	$ —	$ 443,080	$ 457,758
Weighted-average interest rate	7.31 %	7.40 %	7.50 %	7.50 %	— %		

Expected Maturity Dates as of December 31, 2020	2021	2022	2023	2024	2025	Total	Fair Value December 31, 2020
				(dollars in thousands)			
Fixed rate debt	$ 17,299	$ 16,071	$ 24,970	$ 2,040	$ 400,000	$ 460,380	$ 376,781
Weighted-average interest rate	7.23 %	7.31 %	7.40 %	7.50 %	7.50 %		
Variable rate debt	$ 55,900	$ —	$ —	$ 87,500	$ —	$ 143,400	$ 141,536
Weighted-average interest rate (1)	2.97 %	3.01 %	3.01 %	3.01 %	—		

(1) Interest rate of variable rate debt equal to the rate effective at December 31, 2020, held constant for the remaining term of the outstanding borrowing.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Alliance Resource Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2021, the related consolidated statements of operations, comprehensive income (loss), cash flows and partners' capital for the year ended December 31, 2021, and the related notes and financial statement schedule included under Item 15(a)(2) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2021 and the results of its operations and its cash flows for the year ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

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, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 25, 2022 expressed an unqualified opinion.

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 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 the financial statements are free of material misstatement, whether due to error or fraud. Our audit 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 audit 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 audit provides a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates 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 on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

<u>Valuation of workers' compensation and pneumoconiosis benefits</u>

As described further in Note 20 to the financial statements, the Partnership provides income replacement and medical treatment for work-related traumatic injury claims and compensation to survivors of workers who suffer employment-related deaths. The Partnership is also liable to pay benefits for black lung disease (or pneumoconiosis) to eligible employees and former employees and their dependents. As of December 31, 2021, the Partnership's aggregate workers' compensation and pneumoconiosis benefits obligations were approximately $165 million. We identified valuation of workers' compensation and pneumoconiosis benefits as a critical audit matter.

The principal considerations for assessing the valuation of workers' compensation and pneumoconiosis benefits as a critical audit matter are the high level of estimation uncertainty related to determining the frequency and severity of these types of claims, as well as the inherent subjectivity in management's judgment in estimating eligible benefits and the total cost to settle or dispose of these claims. Workers' compensation and pneumoconiosis benefits obligations are determined using actuarial projection methods and numerous assumptions including claim development patterns, costs, and mortality. The estimates rely on the assumption that historical claim patterns are an accurate representation for future claims.

Our audit procedures related to the valuation of workers' compensation and pneumoconiosis benefits included the following, among others.

- We tested the design and operating effectiveness of controls relating to the workers' compensation and pneumoconiosis benefits process including testing controls over management's review of actuarial specialists' liability calculations and the completeness and accuracy of the underlying data.
- We tested management's process for determining the worker's compensation and pneumoconiosis benefit accrual, including evaluating the reasonableness of the methods and significant assumptions used in the calculations with the assistance of actuarial specialists.
- We tested the claims data used in the actuarial calculations by inspecting source documents to test key attributes of the claims data.
- We compared claim development patterns and cost assumptions used in the actuarial calculations for consistency with historical experience and current trends.
- We compared the mortality tables used in the actuarial calculations to publicly available information.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2021.

Tulsa, Oklahoma
February 25, 2022

Report of Independent Registered Public Accounting Firm

To 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 sheet of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2020, the related consolidated statements of operations, comprehensive income (loss), cash flows and partners' capital for each of the two years in the period ended December 31, 2020, and the related notes and financial statement schedule listed in the Index at Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2020, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

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

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

/s/ Ernst & Young LLP

We served as the Partnership's auditor from 2011 to 2021.

Tulsa, Oklahoma
February 23, 2021, except for Note 24, as to which the date is February 25, 2022

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2021 AND 2020
(In thousands, except unit data)

	December 31,	
	2021	**2020**
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 122,403	$ 55,574
Trade receivables	129,531	104,579
Other receivables	680	3,481
Inventories, net	60,302	56,407
Advance royalties	4,958	4,168
Prepaid expenses and other assets	21,354	21,565
Total current assets	339,228	245,774
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	3,608,347	3,554,090
Less accumulated depreciation, depletion and amortization	(1,909,669)	(1,753,845)
Total property, plant and equipment, net	1,698,678	1,800,245
OTHER ASSETS:		
Advance royalties	63,524	56,791
Equity method investments	26,325	27,268
Goodwill	4,373	4,373
Operating lease right-of-use assets	14,158	15,004
Other long-term assets	13,120	16,561
Total other assets	121,500	119,997
TOTAL ASSETS	$ 2,159,406	$ 2,166,016
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 69,586	$ 47,511
Accrued taxes other than income taxes	17,787	25,054
Accrued payroll and related expenses	36,805	28,524
Accrued interest	5,000	5,132
Workers' compensation and pneumoconiosis benefits	12,293	10,646
Current finance lease obligations	840	766
Current operating lease obligations	1,820	1,854
Other current liabilities	17,375	21,919
Current maturities, long-term debt, net	16,071	73,199
Total current liabilities	177,577	214,605
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities, net	418,942	519,421
Pneumoconiosis benefits	107,560	105,068
Accrued pension benefit	25,590	46,965
Workers' compensation	44,911	47,521
Asset retirement obligations	123,517	121,487
Long-term finance lease obligations	618	1,458
Long-term operating lease obligations	12,366	13,078
Other liabilities	22,256	24,146
Total long-term liabilities	755,760	879,144
Total liabilities	933,337	1,093,749
COMMITMENTS AND CONTINGENCIES - (Note 22)		
PARTNERS' CAPITAL:		
ARLP Partners' Capital:		
Limited Partners - Common Unitholders 127,195,219 units outstanding	1,279,183	1,148,565
Accumulated other comprehensive loss	(64,229)	(87,674)
Total ARLP Partners' Capital	1,214,954	1,060,891
Noncontrolling interest	11,115	11,376
Total Partners' Capital	1,226,069	1,072,267
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 2,159,406	$ 2,166,016

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2021, 2020 AND 2019
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2021	**2020**	**2019**
SALES AND OPERATING REVENUES:			
Coal sales	$ 1,386,923	$ 1,232,272	$ 1,762,442
Oil & gas royalties	74,988	42,912	51,735
Transportation revenues	69,607	21,129	99,503
Other revenues	38,458	31,816	48,040
Total revenues	1,569,976	1,328,129	1,961,720
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	943,257	859,656	1,182,100
Transportation expenses	69,607	21,129	99,503
Outside coal purchases	6,372	—	23,357
General and administrative	70,160	59,806	72,997
Depreciation, depletion and amortization	261,377	313,387	309,075
Asset impairments	—	24,977	15,190
Goodwill impairment	—	132,026	—
Total operating expenses	1,350,773	1,410,981	1,702,222
INCOME (LOSS) FROM OPERATIONS	219,203	(82,852)	259,498
Interest expense (net of interest capitalized of $396, $1,325 and $1,211, respectively)	(39,229)	(45,613)	(45,875)
Interest income	88	135	379
Equity method investment income	2,130	907	2,203
Equity securities income	—	—	12,906
Acquisition gain	—	—	177,043
Other income (expense)	(3,020)	(1,593)	561
INCOME (LOSS) BEFORE INCOME TAXES	179,172	(129,016)	406,715
INCOME TAX EXPENSE (BENEFIT)	417	35	(211)
NET INCOME (LOSS)	178,755	(129,051)	406,926
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	(598)	(169)	(7,512)
NET INCOME (LOSS) ATTRIBUTABLE TO ARLP	$ 178,157	$ (129,220)	$ 399,414
EARNINGS PER LIMITED PARTNER UNIT - BASIC AND DILUTED	$ 1.36	$ (1.02)	$ 3.07
WEIGHTED-AVERAGE NUMBER OF UNITS OUTSTANDING – BASIC AND DILUTED	127,195,219	127,164,659	128,116,670

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
FOR THE YEARS ENDED DECEMBER 31, 2021, 2020 AND 2019
(In thousands)

	Year Ended December 31,		
	2021	**2020**	**2019**
NET INCOME (LOSS)	$ 178,755	$ (129,051)	$ 406,926
OTHER COMPREHENSIVE INCOME (LOSS):			
Defined benefit pension plan			
Amortization of prior service cost (1)	186	186	186
Net actuarial gain (loss)	14,921	(5,522)	(7,350)
Amortization of net actuarial loss (1)	4,327	4,128	3,922
Total defined benefit pension plan adjustments	19,434	(1,208)	(3,242)
Pneumoconiosis benefits			
Net actuarial loss	(161)	(7,787)	(23,298)
Amortization of net actuarial loss (gain) (1)	4,172	(686)	(4,582)
Total pneumoconiosis benefits adjustments	4,011	(8,473)	(27,880)
OTHER COMPREHENSIVE INCOME (LOSS)	23,445	(9,681)	(31,122)
COMPREHENSIVE INCOME (LOSS)	202,200	(138,732)	375,804
Less: Comprehensive income attributable to noncontrolling interest	(598)	(169)	(7,512)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO ARLP	$ 201,602	$ (138,901)	$ 368,292

(1) Amortization of prior service cost and actuarial gain or loss is included in the computation of net periodic benefit cost (see Notes 16 and 20 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, 2021, 2020 AND 2019
(In thousands)

	Year Ended December 31,		
	2021	2020	2019
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 178,755	$ (129,051)	$ 406,926
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	261,377	313,387	309,075
Non-cash compensation expense	5,709	3,345	11,934
Asset retirement obligations	3,688	4,033	4,087
Coal inventory adjustment to market	70	3,245	4,895
Equity investment income	(2,130)	(907)	(2,203)
Distributions from equity method investments	2,130	907	2,203
Income from equity securities paid-in-kind	—	—	(712)
Net loss (gain) on sale of property, plant and equipment	(6,592)	(5,850)	109
Asset impairment	—	24,977	15,190
Goodwill impairment	—	132,026	—
Acquisition gain, net	—	—	(177,043)
Cash received on redemption of equity securities in excess of investment	—	—	(11,482)
Valuation allowance of deferred tax assets	(834)	1,151	(413)
Other	212	6,631	5,677
Changes in operating assets and liabilities:			
Trade receivables	(24,952)	56,172	20,841
Other receivables	3,109	(3,225)	3,726
Inventories, net	(4,673)	30,522	(35,082)
Prepaid expenses and other assets	211	(2,514)	6,136
Advance royalties	(7,523)	(7,690)	(9,876)
Accounts payable	19,481	(24,282)	(17,671)
Accrued taxes other than income taxes	(7,267)	9,286	(994)
Accrued payroll and related benefits	8,281	(8,051)	(6,538)
Pneumoconiosis benefits	6,832	2,340	(2,292)
Workers' compensation	(1,292)	1,355	3,845
Other	(9,390)	(7,162)	(15,443)
Total net adjustments	246,447	529,696	107,969
Net cash provided by operating activities	425,202	400,645	514,895
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(122,984)	(121,101)	(305,858)
Change in accounts payable and accrued liabilities	2,594	(8,773)	(81)
Proceeds from sale of property, plant and equipment	7,719	3,762	1,266
Distributions received from investments in excess of cumulative earnings	943	988	2,501
Payments for acquisitions of businesses, net of cash acquired	—	—	(320,232)
Oil & gas reserve acquisition	(30,960)	—	—
Cash received from redemption of equity securities	—	—	134,288
Net cash used in investing activities	(142,688)	(125,124)	(488,116)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under securitization facility	35,000	46,100	184,500
Payments under securitization facility	(90,900)	(64,000)	(202,700)
Proceeds from equipment financings	—	14,705	63,086
Payments on equipment financings	(17,299)	(14,805)	(2,607)
Borrowings under revolving credit facilities	15,000	70,000	400,000
Payments under revolving credit facilities	(102,500)	(237,500)	(320,000)
Borrowings from line of credit	5,340	—	—
Payment on line of credit	(5,340)	—	—
Payments on finance lease obligations	(766)	(8,368)	(46,725)
Payment of debt issuance costs	(113)	(6,280)	—
Payments for purchases of units under unit repurchase program	—	—	(22,892)
Payments for purchase of units and tax withholdings related to settlements under deferred compensation plans	(1,090)	(1,310)	(7,817)
Cash settlement of grants under deferred compensation plan	—	(2,490)	—
Distributions paid to Partners	(52,158)	(51,753)	(278,425)
Other	(859)	(728)	(867)
Net cash used in financing activities	(215,685)	(256,429)	(234,447)
NET CHANGE IN CASH AND CASH EQUIVALENTS	66,829	19,092	(207,668)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	55,574	36,482	244,150
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 122,403	$ 55,574	$ 36,482

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2021, 2020 AND 2019
(In thousands, except unit data)

	Number of Limited Partner Units	Limited Partners' Capital	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Partners' Capital
Balance at January 1, 2019	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
Comprehensive income (loss):					
Net income (loss)	—	(129,220)	—	169	(129,051)
Actuarially determined long-term liability adjustments	—	—	(9,681)	—	(9,681)
Total comprehensive loss					(138,732)
Settlement of deferred compensation plans	279,622	(3,800)	—	—	(3,800)
Common unit-based compensation	—	3,345	—	—	3,345
Distributions on deferred common unit-based compensation	—	(986)	—	—	(986)
Distributions from consolidated company to noncontrolling interest	—	—	—	(728)	(728)
Distributions to Partners	—	(50,767)	—	—	(50,767)
Other	—	(1,489)	—	—	(1,489)
Balance at December 31, 2020	127,195,219	1,148,565	(87,674)	11,376	1,072,267
Comprehensive income:					
Net income	—	178,157	—	598	178,755
Actuarially determined long-term liability adjustments	—	—	23,445	—	23,445
Total comprehensive income					202,200
Settlement of deferred compensation plans	—	(1,090)	—	—	(1,090)
Common unit-based compensation	—	5,709	—	—	5,709
Distributions on deferred common unit-based compensation	—	(1,280)	—	—	(1,280)
Distributions from consolidated company to noncontrolling interest	—	—	—	(859)	(859)
Distributions to Partners	—	(50,878)	—	—	(50,878)
Balance at December 31, 2021	127,195,219	$ 1,279,183	$ (64,229)	$ 11,115	$ 1,226,069

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 general partner.
- References to "Mr. Craft" mean Joseph W. Craft III, the Chairman, President and Chief Executive Officer of MGP.
- 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 our coal mining operations.
- References to "Alliance Minerals" mean Alliance Minerals, LLC, the holding company for our oil and gas minerals interests.
- References to "Alliance Resource Properties" mean Alliance Resource Properties, LLC, the land holding company for certain of our coal mineral interests, including the subsidiaries of Alliance Resource Properties, LLC.

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 general partner, MGP, a Delaware limited liability company which holds a non-economic general partner interest in ARLP. Alliance GP, LLC ("AGP"), which is indirectly wholly owned by Mr. Craft, is the direct owner of MGP.

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.

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 (the "Wing Acquisition"). The Wing Acquisition enhances our ownership position in the Permian Basin and expands our exposure to industry leading operators.

Boulders Acquisition

On October 13, 2021, AR Midland acquired approximately 1,480 oil & gas net royalty acres in the Delaware Basin from Boulders Royalty Corp. ("Boulders") for a purchase price of $31.0 million (the "Boulders Acquisition"). This acquisition also enhanced our ownership position in the Permian Basin

These acquisitions furthered our business strategy to grow our Oil & Gas Royalties segment through accretive acquisitions. See Note 3 – Acquisitions for more information. We now hold approximately 57,000 net royalty acres in premier oil & gas resource plays including our investment in AllDale Minerals III, LP ("AllDale III").

Presentation

The consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of December 31, 2021 and 2020, 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, 2021. All of our intercompany transactions and accounts have been eliminated.

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. All intercompany transactions and accounts have been eliminated.

*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 12 – 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;
- 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 immaterial adjustments representing book overdrafts. We did not have material book overdrafts at December 31, 2021, 2020 and 2019.

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. During 2020, we recognized an impairment charge of $132.0 million consisting of the total carrying amount of goodwill allocated to our Hamilton reporting unit. See Note 5 – Goodwill Impairment for more information. There were no impairments of goodwill during 2021 or 2019.

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 finance 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 29 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 29 years, limited by the remaining estimated life of each mine. Depreciable lives for buildings, office equipment and improvements range from 1 to 29 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 coal mineral reserves. Therefore, our coal mineral rights are depleted based on only proven and probable coal mineral 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 coal mineral reserves. Mine development costs represent costs incurred in establishing access to coal 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.

Leases—We lease buildings and equipment under operating lease agreements that provide for the payment of minimum rentals. We also have noncancelable lease agreements with third parties for land and equipment under finance lease obligations. Some of our arrangements within these agreements have both lease and non-lease components, which are generally accounted for separately. We have elected a practical expedient to account for lease and non-lease components as a single lease component for leases of buildings and office equipment. Our leases have approximate lease terms of 1 to 29 years, some of which include automatic renewals up to ten years which are likely to be exercised, and some of which include options to terminate the lease within one year. We also hold numerous mineral reserve leases with both related parties as well as third parties, none of which are accounted for as an operating lease or as a finance lease.

We review each agreement to determine if an arrangement within the agreement contains a lease at the inception of an arrangement. Once an arrangement is determined to contain either an operating or finance lease with a term greater than 12 months, we recognize a lease liability for the obligation to make lease payments and a right-of-use asset for the right to use the underlying asset for the lease term based on the present value of lease payments over the lease term. The lease term includes all noncancelable periods defined in the lease as well as periods covered by options to extend the lease that we are reasonably certain to exercise. As an implicit borrowing rate cannot be determined under most of our leases, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments.

Expenses related to leases determined to be operating leases will be recognized on a straight-line basis over the lease term including any reasonably assured renewal periods, while those determined to be finance leases will be recognized following a front-loaded expense profile in which interest and amortization are presented separately in the income statement. The determination of whether a lease is accounted for as a finance lease or an operating lease requires management to make estimates primarily about the fair value of the asset and its estimated economic useful life.

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 oil & gas 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 oil & gas mineral interests in unproved properties are also assessed for impairment periodically but at least annually when facts and circumstances indicate that the unproved property will not be transferred to proved properties. 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 if we determine that the unproved property will not be transferred to proved properties. 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.

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 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 $3.8 million, $4.9 million and $9.1 million for the years ending December 31, 2021, 2020 and 2019, respectively. Our intangibles are included in *Prepaid expenses and other assets* and *Other long-term assets* on our consolidated balance sheets at December 31, 2021 and 2020. Our intangibles are summarized as follows:

	December 31, 2021			December 31, 2020		
	Original Cost	**Accumulated Amortization**	**Intangibles, Net**	**Original Cost**	**Accumulated Amortization**	**Intangibles, Net**
			(in thousands)			
Customer contracts and other	10,623	(9,504)	1,119	10,623	(5,744)	4,879
Mining permits	1,500	(418)	1,082	1,500	(373)	1,127
Total	$ 12,123	$ (9,922)	$ 2,201	$ 12,123	$ (6,117)	$ 6,006

Amortization expense attributable to intangible assets is estimated as follows:

Year Ended December 31,	(in thousands)
2022	$ 1,164
2023	45
2024	45
2025	45
2026	45
Thereafter	857

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 13 – 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. We hold an equity method investment in AllDale III through our subsidiary, Alliance Minerals. See Note 13 – Investments for further discussion of our equity method investment in AllDale III.

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,			
	2021		2020	
	(in thousands)			
Advance royalties, affiliates (see Note 21 – Related-Party Transactions)	$	55,613	$	48,389
Advance royalties, third-parties		12,869		12,570
Total advance royalties	$	68,482	$	60,959

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 19 – 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 16 – 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 20 – 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, which primarily relate to sales of thermal coal, 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 sales 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 market prices 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 recognize lease bonus revenue when we execute a lease of 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. The difference between our estimates and the actual amounts received for oil & gas royalty revenue are immaterial and 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. As part of the LTIP, unit awards of non-vested "phantom" or notional units, also referred to as "restricted units", may be granted which upon satisfaction of time and performance-based vesting requirements, entitle the LTIP participant to receive ARLP common units. Certain awards may also contain a minimum-value guarantee payable in ARLP common units or cash that would be paid regardless of whether or not the awards vest, as long as service requirements are met. Annual grant levels, vesting provisions and minimum-value guarantees of restricted units for designated participants are recommended by Mr. Craft, subject to review and approval of the compensation committee of our general partner ("Compensation Committee"). Vesting of all restricted units outstanding is subject to the satisfaction of certain financial tests. If it is not probable the financial tests for a particular grant of restricted units will be met, any previously expensed amounts for that grant are reversed and no future expense will be recognized for that grant. Assuming the financial tests are met, grants of restricted units issued to LTIP participants are generally expected to cliff vest on January 1st of the third year following issuance of the grants. We expect to settle restricted unit grants by delivery of newly-issued ARLP common units, except for the portion of the grants that will satisfy employee tax withholding obligations of LTIP participants. We account for forfeitures of non-vested LTIP restricted unit grants as they occur. As provided under the distribution equivalent rights ("DERs") provisions of the LTIP and the terms of the LTIP restricted unit awards, all non-vested restricted units 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. If it is not probable the financial tests for a particular grant of restricted units will be met, any previously paid DER amounts for that grant are reversed from Partners' Capital and recorded as compensation expense and any future DERs, for that grant, if any, will be recognized as compensation expense when paid.

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 17 – Common Unit-Based 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 Not Yet Adopted—In November 2021, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2021-10, Government Assistance (Topic 832): Disclosures by Business Entities about Government Assistance ("ASU 2021-10"). ASU 2021-10 increases the transparency of government assistance including the disclosure of (1) the types of assistance, (2) an entity’s accounting for the assistance, and (3) the effect of the assistance on an entity’s financial statements. ASU 2021-10 is effective for fiscal years beginning after December 15, 2021, with early adoption permitted. The adoption of ASU 2021-10 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 Oil & Gas Royalties segment.

Because the underlying mineral interests held by AllDale I & II include royalty interests in both developed properties and undeveloped 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.

The following table summarizes the final fair value allocation of assets acquired and liabilities assumed as of the AllDale Acquisition Date:

	(in thousands)	
Cash and cash equivalents	$	900
Mineral interests in proved properties		184,032
Mineral interests in unproved properties		291,190
Receivables		9,326
Accounts payable		(1,921)
Net assets acquired	$	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 from the AllDale Acquisition Date through December 31, 2019 are as follows:

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

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 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 8 – 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 Oil & Gas Royalties segment. Concurrent with the Wing Acquisition, JC Resources LP, an entity owned by 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 developed properties and undeveloped 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.

The following table summarizes our final fair value allocation of assets acquired as of the Wing Acquisition Date:

		(in thousands)
Mineral interests in proved properties	$	75,071
Mineral interests in unproved properties		67,701
Receivables		2,155
Net assets acquired	$	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 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 weighted average cost of capital. 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 represents the fair value given the short-term nature of the receivables.

The amounts of revenue and earnings from the mineral interests acquired in the Wing Acquisition included in our consolidated statements of income from the Wing Acquisition Date through December 31, 2019 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 year ended December 31, 2019. 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, 2019. These pro forma amounts have been calculated after applying our accounting policies.

		Year Ended December 31, 2019 (in thousands)
Total revenues		
As reported	$	1,961,720
Pro forma		1,966,291
Net income		
As reported	$	406,926
Pro forma		411,217

Boulders

On October 13, 2021, AR Midland acquired approximately 1,480 oil & gas net royalty acres in the Delaware Basin from Boulders for a purchase price of $31.0 million. This acquisition gives us increased exposure to a prolific area of the Delaware Basin and is within close proximity to reserves acquired in the AllDale and Wing Acquisitions. The acreage is mostly undeveloped. Because more than 90% of the mineral interests acquired in the Boulders Acquisition represent undeveloped properties, including proved undeveloped, we have determined that the Boulders Acquisition should be accounted for as an asset acquisition. We have allocated the purchase price to the acquired reserves as follows:

	(in thousands)
Mineral interests in proved properties	$ 12,542
Mineral interests in unproved properties	18,419
	$ 30,961

4. LONG-LIVED ASSET IMPAIRMENTS

During the year ended December 31, 2020, we recorded $23.5 million of non-cash asset impairment charges in our Illinois Basin Coal Operations segment due to sealing our idled Gibson North mine, resulting in its permanent closure, and a decrease in the fair value of certain mining equipment at our idled operations and greenfield coal mineral resources as a result of weakened coal market conditions including the impact of the COVID-19 pandemic. During the same period, we also recorded an asset impairment charge of $1.5 million in our Coal Royalties segment due to a decrease in the fair value of greenfield coal mineral resources held by Alliance Resource Properties near our coal mining operations in the Illinois Basin. See Note 24 – Segment Information for more information about our segments.

During the year ended December 31, 2019, we recorded asset impairment charges in our Illinois Basin Coal Operations segment and our Coal Royalties segment of $7.5 million and $7.7 million, respectively, due to the cessation of coal production at our Dotiki mine, effective August 16, 2019, in an effort to focus on maximizing production at our lower-cost mines in the Illinois Basin. We adjusted the carrying value of assets associated with the Dotiki mine, including coal mineral reserves and resources held at Alliance Resource Properties, from $35.9 million to their fair value of $25.8 million and accrued $5.1 million with respect to scheduled payments to WKY CoalPlay, LLC ("WKY CoalPlay") for leased coal mineral reserves and resources from which we may not receive future economic benefit. See Note 12 – Variable Interest Entities for more information about WKY CoalPlay.

The fair values of the impaired assets were determined using a market approach, which represents Level 3 fair value measurements under the fair value hierarchy. The fair value analysis used assumptions regarding the marketability of certain mining and coal mineral reserve and resource assets near our Illinois Basin coal mining operations.

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

5. GOODWILL IMPAIRMENT

During the first quarter of 2020, we considered whether an interim test of our consolidated goodwill of $136.4 million was necessary. Our consolidated goodwill included $132.0 million recorded in our Illinois Basin Coal Operations segment in conjunction with our acquisition of the Hamilton County Coal, LLC ("Hamilton") mine on July 31, 2015. We assessed certain events and changes in circumstances, including (a) adverse industry and market developments, including the impact of the COVID-19 pandemic, (b) our response to these developments, including temporarily ceasing production at several mines, including our Hamilton mine and (c) our actual performance during the quarter. After consideration of these events and changes in circumstances, we performed an interim test of the goodwill associated with Hamilton comparing Hamilton's carrying amount to its fair value.

We estimated the fair value of Hamilton using an income approach utilizing a discounted cash flow model. The assumptions used in the discounted cash flow model included estimated production, forward coal prices, operating expenses, capital expenditures and a weighted average cost of capital. Our forecasts of future cash flows considered market conditions at the time of the assessment and our estimate of the mine's performance in future years based on the information available to us. Key assumptions used in our valuation were not observable in active markets; therefore, the fair value measurements represent Level 3 fair value measurements. The fair value of Hamilton was determined to be below its carrying amount (including goodwill) by more than the recorded balance of goodwill associated with the mine. Accordingly, we recognized an impairment charge of $132.0 million consisting of the total carrying amount of goodwill associated with Hamilton. This impairment charge reduced our consolidated goodwill balance to $4.4 million. During the first quarter of 2020, we also performed an interim test on our remaining goodwill balances not associated with Hamilton and concluded no impairment was necessary for our other reporting units.

6. INVENTORIES

Inventories consist of the following**:**

	December 31, 2021	December 31, 2020
	(in thousands)	
Coal	$ 24,845	$ 19,756
Supplies (net of reserve for obsolescence of $5,554 and $5,547, respectively)	35,457	36,651
Total inventories, net	$ 60,302	$ 56,407

For the year ended December 31, 2020, we recorded lower of cost or net realizable value adjustments of $3.2 million to our coal inventories as a result of lower coal sale prices and higher cost per ton due to the impact of lower production on our fixed costs per ton in addition to the impact of challenging market conditions on our production levels. The lower of cost or net realizable value adjustments reflect the impacts of the challenging market conditions and were primarily attributable to the Mettiki and Hamilton mining complexes.

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

7. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following:

	December 31, 2021	December 31, 2020
	(in thousands)	
Mining equipment and processing facilities	$ 1,896,470	$ 1,896,324
Land and coal mineral rights	458,440	454,310
Oil & gas mineral interests	647,864	616,904
Buildings, office equipment, improvements and other miscellaneous equipment	282,902	279,938
Construction, mine development and other projects in progress	44,217	25,799
Mine development costs	278,454	280,815
Property, plant and equipment, at cost	3,608,347	3,554,090
Less accumulated depreciation, depletion and amortization	(1,909,669)	(1,753,845)
Total property, plant and equipment, net	$ 1,698,678	$ 1,800,245

Depreciation, depletion and amortization expense related to property, plant and equipment was $256.9 million, $297.0 million and $312.4 million for the years ended December 31, 2021, 2020 and 2019, respectively.

At December 31, 2021 and 2020, land and coal mineral rights above include $37.4 million and $37.5 million, respectively, of carrying value associated with coal mineral reserves and resources attributable to properties where we or a third party to which we lease coal mineral reserves and resources are not currently engaged in mining operations or leasing to third parties, and therefore, the coal mineral reserves are not currently being depleted. We believe that the carrying value of these coal mineral reserves will be recovered.

At December 31, 2021 and 2020, our oil & gas mineral interests noted in the table above includes the carrying value of our unproved oil & gas mineral interests totaling $355.1 million and $340.5 million, respectively. 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 2021, we did not incur material mine development costs. During 2020, we incurred $13.1 million in mine development costs, primarily related to the development of our Excel Mine No. 5 at our MC Mining complex. 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.

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

8. LONG-TERM DEBT

Long-term debt consists of the following:

	Principal		Unamortized Discount and Debt Issuance Costs	
	December 31,		December 31,	
	2021	2020	2021	2020
	(in thousands)			
Revolving credit facility	$ —	$ 87,500	$ (5,019)	$ (7,196)
Senior notes	400,000	400,000	(3,048)	(3,964)
Securitization facility	—	55,900	—	—
May 2019 equipment financing	1,503	4,956	—	—
November 2019 equipment financing	31,972	42,367	—	—
June 2020 equipment financing	9,605	13,057	—	—
	443,080	603,780	(8,067)	(11,160)
Less current maturities	(16,071)	(73,199)	—	—
Total long-term debt	$ 427,009	$ 530,581	$ (8,067)	$ (11,160)

Credit Facility. On March 9, 2020, our Intermediate Partnership entered into a Fifth Amended and Restated Credit Agreement (the "Credit Agreement") with various financial institutions. The Credit Agreement provides for a $459.5 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 March 9, 2024. Concurrently with the entry into the Credit Agreement, we reorganized the entities holding our oil & gas interests such that Alliance Royalty, LLC became a direct wholly owned subsidiary of Alliance Minerals. We incurred debt issuance costs in 2020 of $6.3 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 certain of our Intermediate Partnership's material direct and indirect subsidiaries (the "Restricted Subsidiaries") and is secured by substantially all of the assets of the Restricted Subsidiaries. The Credit Agreement is also guaranteed by Alliance Minerals but the oil and gas minerals assets of Alliance Minerals and its direct and indirect subsidiaries (collectively with Alliance Minerals, the "Unrestricted Subsidiaries") are not collateral under the Credit Agreement. Borrowings under the Revolving Credit Facility bear interest, at our option, 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 2.45% as of December 31, 2021. At December 31, 2021, we had $44.1 million of letters of credit outstanding with $415.4 million available for borrowing under the Revolving Credit Facility. We 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 the Intermediate Partnership and its Restricted Subsidiaries including, among other things, restrictions on incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates, including transactions with Unrestricted Subsidiaries. In each case, these restrictions are subject to various exceptions. In addition, the payment of cash distributions is restricted if such payment would result in a fixed charge coverage ratio of less than 1.0 to 1.0 (as defined in the Credit Agreement) for the four most recently ended fiscal quarters. 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, (b) a cash flow to interest expense ratio of not less than 3.0 to 1.0 and (c) a first lien debt to cash flow ratio of not more than 1.5 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt to cash flow ratio, cash flow to interest expense ratio and first lien debt to cash flow ratio were 0.95 to 1.0, 11.91 to 1.0 and 0.10 to 1.0, respectively, for the trailing twelve months ended December 31, 2021. We remained in compliance with the covenants of the Credit Agreement as of December 31, 2021 and anticipate remaining in compliance with the covenants.

Net restricted assets, as defined by the Securities and Exchange Commission, refers to the amount of our consolidated subsidiaries' net assets for which the ability to transfer funds to ARLP in the form of cash dividends, loans, advances, or transfers is restricted. As a result of the restrictions contained in the Credit Agreement and our current compliance ratios, the amount of our net restricted assets at December 31, 2021 was $372.0 million.

Senior Notes. On April 24, 2017, the Intermediate Partnership and Alliance Resource Finance Corporation (as co-issuer), a wholly owned subsidiary of the Intermediate Partnership ("Alliance Finance"), 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. The issuers of the Senior Notes may redeem all or a part of the notes at any time at redemption prices set forth in the indenture governing the Senior Notes.

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"). In January 2021, we reduced the borrowing availability under the facility to $60.0 million. Under the Securitization Facility, certain subsidiaries sell certain 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 $60.0 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. The agreement governing the Securitization Facility contains customary terms and conditions, including limitations with regards to certain customer credit ratings. In January 2022, we extended the term of the Securitization Facility to January 2023. The Securitization Facility was previously scheduled to mature in January 2022. At December 31, 2021, we had no outstanding balance 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 customary terms and events of default and an implicit interest rate of 4.75%, providing 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. Upon maturity, the equipment will revert back to the Intermediate Partnership.

June 2020 Equipment Financing. On June 5, 2020, the Intermediate Partnership entered into an equipment financing arrangement accounted for as debt, wherein the Intermediate Partnership received $14.7 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 "June 2020 Equipment Financing"). The June 2020 Equipment Financing contains customary terms and events of default and provides for forty-eight monthly payments with an implicit interest rate of 6.1%, maturing on June 5, 2024. Upon maturity, the equipment will revert back to the Intermediate Partnership.

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, 2021, 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)
2022	$ 16,071
2023	24,970
2024	2,039
2025	400,000
	$ 443,080

9. LEASES

The components of lease expense were as follows:

	December 31,		
	2021	**2020**	**2019**
		(in thousands)	
Finance lease cost:			
Amortization of right-of-use assets	$ 597	$ 704	$ 14,608
Interest on lease liabilities	147	377	2,085
Operating lease cost	2,404	3,873	9,169
Short-term lease cost	200	84	464
Variable lease cost	1,306	1,375	1,360
Total lease cost	$ 4,654	$ 6,413	$ 27,686

Rental expense was $3.3 million, $5.2 million and $11.0 million for the years ended December 31, 2021, 2020 and 2019 respectively.

Supplemental cash flow information related to leases was as follows:

	December 31,		
	2021	**2020**	**2019**
		(in thousands)	
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows for operating leases	$ 2,367	$ 3,870	$ 9,124
Operating cash flows for finance leases	$ 147	$ 377	$ 891
Financing cash flows for finance leases	$ 766	$ 8,368	$ 46,725
Right-of-use assets obtained in exchange for lease obligations:			
Operating leases	$ 189	$ 278	$ 25,593

Supplemental balance sheet information related to leases was as follows:

	December 31, 2021	December 31, 2020
	(in thousands)	
Finance leases:		
Property and equipment finance lease assets, gross	$ 5,485	$ 5,485
Accumulated depreciation	(4,464)	(3,867)
Property and equipment finance lease assets, net	$ 1,021	$ 1,618

	December 31, 2021	December 31, 2020
Weighted average remaining lease term		
Operating leases	15.5 years	13.4 years
Finance leases	3.5 years	3.9 years
Weighted average discount rate		
Operating leases	6.0 %	6.0 %
Finance leases	7.4 %	8.0 %

Maturities of lease liabilities as of December 31, 2021 were as follows:

	Operating leases	Finance leases
	(in thousands)	
2022	$ 2,257	$ 912
2023	2,073	139
2024	1,853	139
2025	1,539	139
2026	1,088	140
Thereafter	13,284	140
Total lease payments	22,094	1,609
Less imputed interest	(7,908)	(151)
Total	$ 14,186	$ 1,458

10. FAIR VALUE MEASUREMENTS

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

	December 31, 2021			December 31, 2020		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in thousands)					
Long-term debt	$ —	$ 457,758	$ —	$ —	$ 518,317	$ —
Total	$ —	$ 457,758	$ —	$ —	$ 518,317	$ —

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

8 – 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.

11. PARTNERS' CAPITAL

Distributions

Our available cash that is not used for unit repurchases may, at the discretion of our general partner, be distributed 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. The following table summarizes the quarterly per unit distribution paid during each quarter of 2019 through 2021:

	Year Ended December 31,		
	2021	2020	2019
First Quarter	$ —	$ 0.400	$ 0.530
Second Quarter	$ 0.100	$ —	$ 0.535
Third Quarter	$ 0.100	$ —	$ 0.540
Fourth Quarter	$ 0.200	$ —	$ 0.540

On January 28, 2022, we declared a quarterly distribution of $0.25 per unit, totaling approximately $31.8 million, on all our common units outstanding, which was paid on February 14, 2022, to all unitholders of record on February 7, 2022.

Unit Repurchase Program

In May 2018, the board of directors of our managing general partner ("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. No unit repurchases were made during the year ended December 31, 2021. Since inception of the unit repurchase program, we have repurchased and retired 5,460,639 units at an average unit price of $17.12 for an aggregate purchase price of $93.5 million.

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 12 – Variable Interest Entities, Note 16 –Employee Benefit Plans and Note 20 – Accrued Workers' Compensation and Pneumoconiosis Benefits for further information.

12. 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% member interest in Cavalier Minerals, and Bluegrass Minerals owns a 4% member 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 distribution. 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	109,994		4,582

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 operations.

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 is 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 13 – Investments for more information.

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

13. INVESTMENTS

AllDale III

As discussed in Note 12 – 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,		
	2021	2020	2019
		(in thousands)	
Beginning balance	$ 27,268	$ 28,529	$ 28,974
Equity method investment income	2,130	907	2,203
Distributions received	(3,073)	(1,895)	(2,648)
Other	—	(273)	—
Ending balance	$ 26,325	$ 27,268	$ 28,529

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.

14. 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 24 – Segment Information.

	Coal Operations		Royalties		Other,	
	Illinois Basin	Appalachia	Oil & Gas	Coal	Corporate and Elimination	Consolidated
			(in thousands)			
Year Ended December 31, 2021						
Coal sales	$ 873,930	$ 512,993	$ —	$ —	$ —	$ 1,386,923
Oil & gas royalties	—	—	74,988	—	—	74,988
Coal royalties	—	—	—	51,402	(51,402)	—
Transportation revenues	41,001	28,606	—	—	—	69,607
Other revenues	4,666	3,940	2,197	69	27,586	38,458
Total revenues	$ 919,597	$ 545,539	$ 77,185	$ 51,471	$ (23,816)	$ 1,569,976
Year Ended December 31, 2020						
Coal sales	$ 755,208	$ 477,064	$ —	$ —	$ —	$ 1,232,272
Oil & gas royalties	—	—	42,912	—	—	42,912
Coal royalties	—	—	—	42,112	(42,112)	—
Transportation revenues	12,817	8,312	—	—	—	21,129
Other revenues	1,932	14,954	229	105	14,596	31,816
Total revenues	$ 769,957	$ 500,330	$ 43,141	$ 42,217	$ (27,516)	$ 1,328,129
Year Ended December 31, 2019						
Coal sales	$ 1,128,588	$ 628,406	$ —	$ —	$ 5,448	$ 1,762,442
Oil & gas royalties	—	—	51,735	—	—	51,735
Coal royalties	—	—	—	57,737	(57,737)	—
Transportation revenues	94,686	4,817	—	—	—	99,503
Other revenues	13,017	11,166	1,301	23	22,533	48,040
Total revenues	$ 1,236,291	$ 644,389	$ 53,036	$ 57,760	$ (29,756)	$ 1,961,720

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, 2021 and disaggregated by segment and contract duration.

	2022	2023	2024	2025 and Thereafter	Total
			(in thousands)		
Illinois Basin Coal Operations coal revenues	$ 913,305	$ 321,079	$ 183,189	$ 39,789	$ 1,457,362
Appalachia Coal Operations coal revenues	463,334	70,595	49,436	—	583,365
Total coal revenues (1)	$ 1,376,639	$ 391,674	$ 232,625	$ 39,789	$ 2,040,727

(1) Coal revenues generally consists of consolidated revenues excluding our Oil & Gas Royalties segment as well as intercompany revenues from our Coal Royalties segment.

15. EARNINGS PER LIMITED PARTNER UNIT

We utilize the two-class method in calculating basic and diluted earnings per limited partner unit ("EPU"). Net income attributable to ARLP is allocated to limited partners and participating securities under deferred compensation plans, which include rights to nonforfeitable distributions or distribution equivalents. Net losses attributable to ARLP are allocated to limited partners but not to participating securities. Our participating securities are outstanding restricted unit awards under our LTIP and phantom units in notional accounts under our SERP and the Directors' Deferred Compensation Plan.

The following is a reconciliation of net income (loss) 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,		
	2021	2020	2019
	(in thousands, except per unit data)		
Net income (loss) attributable to ARLP	$ 178,157	$ (129,220)	$ 399,414
Less:			
Distributions to participating securities	(2,334)	—	(4,254)
Undistributed earnings attributable to participating securities	(2,403)	—	(2,237)
Net income (loss) attributable to ARLP available to limited partners	$ 173,420	$ (129,220)	$ 392,923
Weighted-average limited partner units outstanding – basic and diluted	127,195	127,165	128,117
Earnings per limited partner unit - basic and diluted (1)	$ 1.36	$ (1.02)	$ 3.07

(1) 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, 2021, 2020 and 2019, the combined total of LTIP, SERP and Directors' Deferred Compensation Plan units of 1,967,672, 773,664 and 1,284,013, respectively, were considered anti-dilutive under the treasury stock method.

16. 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 $17.7 million, $16.1 million and $21.1 million for the years ended December 31, 2021, 2020 and 2019, 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, 2021 and 2020 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements:

	December 31,	
	2021	**2020**
	(dollars in thousands)	
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 147,934	$ 136,425
Interest cost	3,438	4,185
Actuarial loss (gain)	(6,406)	12,396
Benefits paid	(5,400)	(5,072)
Benefit obligations at end of year	139,566	147,934
Change in plan assets:		
Fair value of plan assets at beginning of year	100,969	91,567
Employer contribution	3,312	1,739
Actual return on plan assets	15,095	12,735
Benefits paid	(5,400)	(5,072)
Fair value of plan assets at end of year	113,976	100,969
Funded status at the end of year	$ (25,590)	$ (46,965)
Amounts recognized in balance sheet:		
Non-current liability	$ (25,590)	$ (46,965)
Amounts recognized in accumulated other comprehensive income consists of:		
Prior service cost	$ (568)	$ (754)
Net actuarial loss	(27,271)	(46,519)
	$ (27,839)	$ (47,273)
Weighted-average assumption to determine benefit obligations as of December 31,		
Discount rate	2.73%	2.37%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,		
Discount rate	2.37%	3.15%
Expected return on plan assets	6.50%	6.50%

The actuarial gain component of the change in benefit obligations in 2021 was primarily attributable to an increase in the discount rate compared to December 31, 2020. The actuarial loss component of the change in benefit obligations in 2020 was primarily attributable to a decrease in the discount rate compared to December 31, 2019, offset in part by updated mortality tables.

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, 2021	**Asset allocation assumption**
Equity securities	62%
Fixed income securities	33%
Real estate	5%
	100%

The actual return on plan assets was 15.1% and 14.2% for the years ended December 31, 2021 and 2020, respectively.

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Components of net periodic benefit cost:			
Interest cost	$ 3,438	$ 4,185	$ 4,864
Expected return on plan assets	(6,580)	(5,861)	(4,932)
Amortization of prior service cost	186	186	186
Amortization of net loss	4,327	4,128	3,922
Net periodic benefit cost (1)	$ 1,371	$ 2,638	$ 4,040

(1) Nonservice components of net periodic benefit cost are included in the *Other income (expense)* line item within our consolidated statements of income.

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive loss:		
Net actuarial gain (loss)	$ 14,921	$ (5,522)
Reversal of amortization item:		
Prior service cost	186	186
Net actuarial loss	4,327	4,128
Total recognized in accumulated other comprehensive loss	19,434	(1,208)
Net periodic benefit cost	(1,371)	(2,638)
Total recognized in net periodic benefit cost and accumulated other comprehensive loss	$ 18,063	$ (3,846)

Estimated future benefit payments as of December 31, 2021 are as follows:

Year Ended December 31,	(in thousands)
2022	$ 5,938
2023	6,190
2024	6,407
2025	6,591
2026	6,733
2027-2031	34,859
	$ 66,718

As a result of certain pension plan contribution relief provided by the American Rescue Plan Act enacted in March 2021, we do not expect to make contributions to the Pension Plan during 2022.

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 Employee Retirement Income Security Act of 1974 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. Total account performance is reviewed at least annually, using a dynamic benchmark approach to track investment performance. General asset allocation guidelines at December 31, 2021 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,	
	2021	**2020**
	(in thousands)	
Cash and cash equivalents (a)	$ 4,426	$ 3,888
Commingled investment funds measured at net asset value (b):		
Equities - Global	24,868	17,549
Equities - United States	41,140	31,835
Equities - United States futures	(2,055)	(2,616)
Equities - International developed markets	16,382	8,920
Equities - International developed markets futures	(16,260)	(4,921)
Equities - International emerging markets	(3,363)	6,600
Equities - International emerging markets futures	7,024	(975)
Fixed income - Investment grade	27,095	25,703
Fixed income - High yield	177	10,056
Fixed income - Emerging markets	—	2,664
Fixed income - Futures	(689)	(1,265)
Real estate	15,231	3,531
Total	$ 113,976	$ 100,969

(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.

17. COMMON UNIT-BASED 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. As part of our LTIP, unit awards of non-vested "phantom" or notional units, also referred to as "restricted units", may be granted which upon satisfaction of time and performance-based vesting requirements, entitle the LTIP participant to receive ARLP common units. Certain awards may also contain a minimum-value guarantee payable in ARLP common units or cash that would be paid regardless of whether or not the awards vest, as long as service requirements are met.

Annual grant levels, vesting provisions and minimum-value guarantees of restricted units for designated participants are recommended by Mr. Craft, subject to review and approval of the Compensation Committee. Vesting of all restricted units outstanding is subject to the satisfaction of certain financial tests. If it is not probable the financial tests for a particular grant of restricted units will be met, any previously expensed amounts for that grant are reversed and no future expense will be recognized for that grant. Assuming the financial tests are met, grants of restricted units issued to LTIP participants are generally expected to cliff vest on January 1st of the third year following issuance of the grants. We expect to settle restricted unit grants by delivery of newly-issued ARLP common units, except for the portion of the grants that will satisfy employee tax withholding obligations of LTIP participants. We account for forfeitures of non-vested LTIP restricted unit grants as they occur. As provided under the DERs provisions of the LTIP and the terms of the LTIP restricted unit awards, all non-vested restricted units 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. If it is not probable the financial tests for a particular grant of restricted units will be met, any previously paid DER amounts for that grant are reversed from Partners' Capital and recorded as compensation expense and any future DERs, for that grant, if any, will be recognized as compensation expense when paid.

A summary of non-vested LTIP grants of restricted units is as follows:

	Number of units	Weighted average grant date fair value per unit	Intrinsic value (in thousands)
Non-vested grants at January 1, 2019	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
Granted (2)	1,430,489	5.02	
Vested (3)	(919,524)	21.70	
Grants canceled (4)	(675,302)	18.62	
Forfeited	(8,552)	20.16	
Non-vested grants at December 31, 2020	1,430,489	5.02	6,409
Granted (5)	1,818,190	6.03	
Forfeited	(118,204)	5.48	
Non-vested grants at December 31, 2021	3,130,475	5.59	39,569

(1) During the year ended December 31, 2019, we issued 596,650 unrestricted common units to LTIP participants. The remaining vested units were settled in cash to satisfy tax withholding obligations of the LTIP participants.

(2) In December 2020, we modified the vesting requirements for certain restricted units that we granted in February 2020 which were determined to be improbable of vesting under the original vesting requirements (the "2020 Grants"). The new vesting requirements make it probable the modified restricted units will vest. Also in December 2020, an additional 578,114 restricted units under these modified vesting requirements were granted. The grant date fair value reflects the modification date fair value for those awards that were modified.

(3) In February 2020, we issued 279,622 unrestricted common units to LTIP participants as a result of satisfying the vesting requirements for 424,486 restricted units that were granted in 2017. The remaining vested units were settled in cash to satisfy tax withholding obligations of the LTIP participants. In December 2020, we accelerated the vesting requirements for 495,038 restricted units that were granted in 2018 (the "2018 Grants") and settled these restricted units in cash.

(4) In December 2020, 675,302 restricted units that were granted in 2019 (the "2019 Grants") were canceled since it was determined that the vesting requirements for these restricted units were not probable of being satisfied.

(5) In April 2021, we granted 921,430 restricted units and 896,760 restricted units that have minimum-value guarantees of $2.53 per unit and $3.79 per unit, respectively, regardless of whether or not the awards vest.

For the years ended December 31, 2021, 2020 and 2019, our LTIP expense for grants of restricted units was $5.4 million, $8.1 million and $10.4 million, respectively. LTIP expense for grants of restricted units for the year ended December 31, 2020 includes the impact of the reversal of the 2019 Grants, the modification of the 2020 Grants and incremental compensation cost associated with the cash settlement of the 2018 Grants. The cash settlement of the 2018 Grants was the first time we have settled restricted units in cash and we currently do not expect to do so again in the future. The cash settlement of the 2018 Grants resulted in $5.4 million in incremental compensation cost. The 2019 Grants were determined to be not probable of vesting therefore $4.8 million of cumulative previously recognized expense was reversed in 2020, offset in part by related DERs for the 2019 Grants previously recorded to equity and then expensed in 2020. The 2020 Grants were determined to be improbable of vesting therefore the Compensation Committee modified the awards to change the vesting requirement, which made the grants probable of vesting, and granted additional restricted units under these modified vesting requirements as previously discussed. As a result, the grant date fair value of the modified awards was changed to reflect the modification date fair value of the awards resulting in a net reduction in LTIP expense of $1.0 million for the year ended December 31, 2020.

The total obligation associated with LTIP grants of restricted units as of December 31, 2021 and 2020 was $6.7 million and $1.3 million, respectively, and is included in the partners' capital *Limited partners-common unitholders* line item in our consolidated balance sheets. As of December 31, 2021, there was $10.8 million in total unrecognized compensation expense related to the non-vested LTIP restricted unit grants that are expected to vest. That expense is expected to be recognized over a weighted-average period of 1.6 years.

On January 26, 2022, the Compensation Committee authorized additional grants of 694,919 restricted units, of which 687,719 units were granted. These restricted units have minimum-value guarantees of either $9.62 or $6.41 per unit, regardless of whether or not the awards vest.

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, 2019	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
Granted	129,265	5.25	
Phantom units outstanding as of December 31, 2020	760,630	22.04	3,408
Granted	46,638	9.45	
Issued (1)	(138,570)	25.86	
Phantom units outstanding as of December 31, 2021	668,698	20.13	8,452

(1) During the years ended December 31, 2021 and 2019, we issued ARLP common units that we purchased on the open market of 102,962 and 115,484, respectively, to participants under the SERP and Directors' Deferred Compensation Plan. Units issued in 2021 were net of units settled in cash to satisfy tax withholding obligations.

Total SERP and Directors' Deferred Compensation Plan expense was $0.4 million, $0.7 million and $1.6 million for the years ended December 31, 2021, 2020 and 2019, respectively. As of December 31, 2021 and 2020, the total obligation associated with the SERP and Directors' Deferred Compensation Plan was $13.5 million and $16.8 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.

18. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31, 2021	2020	2019
		(in thousands)	
Cash Paid For:			
Interest	$ 36,402	$ 44,226	$ 43,093
Income taxes	$ 11	$ 12	$ —
Non-Cash Activity:			
Accounts payable for purchase of property, plant and equipment	$ 8,325	$ 5,731	$ 14,504
Right-of-use assets acquired by operating lease	$ 189	278	25,593
Market value of common units issued under deferred compensation plans before tax withholding requirements	$ 1,082	$ 3,837	$ 17,415

19. 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, 2021	Year Ended December 31, 2020
	(in thousands)	
Beginning balance	$ 127,898	$ 137,514
Accretion expense	3,688	4,033
Payments	(1,383)	(1,769)
Allocation of liability associated with acquisitions, mine development and change in assumptions	896	(11,880)
Ending balance	$ 131,099	$ 127,898

For the year ended December 31, 2021, the allocation of liability associated with acquisition, mine development and change in assumptions was immaterial.

For the year ended December 31, 2020, the allocation of liability associated with acquisition, mine development and change in assumptions was a net decrease of $11.9 million. This net decrease was attributable to lower cost assumptions and completion of certain reclamation obligations across all operations, permit modifications and extension of projected mine life estimates at certain mines, partially offset by acquisition of property with existing reclamation liabilities.

The impact of discounting our estimated cash flows resulted in reducing the accrual for asset retirement obligations by $98.3 million and $102.1 million at December 31, 2021 and 2020, respectively. Estimated payments of asset retirement obligations as of December 31, 2021 are as follows:

Year Ended December 31,	(in thousands)
2022	$ 7,582
2023	2,232
2024	558
2025	3,788
2026	7,256
Thereafter	208,021
Aggregate undiscounted asset retirement obligations	229,437
Effect of discounting	(98,338)
Total asset retirement obligations	131,099
Less: current portion	(7,582)
Non-current asset retirement obligations	$ 123,517

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, 2021 and 2020, we had approximately $173.9 million and $171.1 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.

20. 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,	
	2021	2020
	(in thousands)	
Beginning balance	$ 54,739	$ 53,384
Accruals increase	5,168	5,146
Payments	(10,725)	(8,482)
Interest accretion	926	1,278
Valuation loss	3,340	3,413
Ending balance	$ 53,448	$ 54,739

The discount rate used to calculate the estimated present value of future obligations for workers' compensation was 2.41% and 1.95% at December 31, 2021 and 2020, respectively.

The valuation loss in 2021 was primarily attributable to unfavorable changes in claims development partially offset by an increase in the discount rate used to calculate the estimated present value of future obligations. The 2020 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.

As of December 31, 2021 and 2020, we had $100.4 million and $95.2 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, 2021 and 2020 are $5.7 million and $7.1 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,	
	2021	2020
	(in thousands)	
Benefit obligations at beginning of year	$ 108,496	$ 97,683
Service cost	4,021	3,526
Interest cost	2,545	2,998
Actuarial loss	161	7,787
Benefits and expenses paid	(3,907)	(3,498)
Benefit obligations at end of year	$ 111,316	$ 108,496

The following is a reconciliation of the changes in the pneumoconiosis benefit obligation recognized in accumulated other comprehensive loss:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Net actuarial loss	$ (161)	$ (7,787)	$ (23,298)
Reversal of amortization item:			
Net actuarial loss (gain)	4,172	(686)	(4,582)
Total recognized in accumulated other comprehensive loss	$ 4,011	$ (8,473)	$ (27,880)

The discount rate used to calculate the estimated present value of future obligations for pneumoconiosis benefits was 2.73%, 2.38% and 3.12% at December 31, 2021, 2020 and 2019, respectively.

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Amount recognized in accumulated other comprehensive loss consists of:			
Net actuarial loss	$ 36,388	$ 40,399	$ 31,927

The actuarial loss component of the change in benefit obligations in 2021 was primarily attributable to unfavorable assumption changes regarding future medical and legal expense levels. These components were offset in part by a) an increase in the discount rate used to calculate the estimated present value of the future obligations and b) favorable black lung claims experience and other demographic changes in the at-risk population. The actuarial loss component of the change in benefit obligations in 2020 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 the assumptions regarding future medical benefits and legal expenses. These components were partially offset in part by favorable 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,	
	2021	2020
	(in thousands)	
Workers’ compensation claims	$ 53,448	$ 54,739
Pneumoconiosis benefit claims	111,316	108,496
Total obligations	164,764	163,235
Less current portion	(12,293)	(10,646)
Non-current obligations	$ 152,471	$ 152,589

Both the pneumoconiosis benefit and workers' compensation obligations were unfunded at December 31, 2021 and 2020.

The pneumoconiosis benefit and workers' compensation expense consists of the following components:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Black lung benefits:			
Service cost	$ 4,021	$ 3,526	$ 2,593
Interest cost (1)	2,545	2,998	3,044
Net amortization (1)	4,172	(686)	(4,582)
Total pneumoconiosis expense	10,738	5,838	1,055
Workers' compensation expense	8,339	12,305	17,541
Net periodic benefit cost	$ 19,077	$ 18,143	$ 18,596

(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.

21. RELATED-PARTY TRANSACTIONS

We have continuing related-party transactions with MGP and its affiliates. The Board of Directors and its conflicts committee ("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.

Line of Credit

On February 19, 2021, we entered into a line of credit arrangement (the "Line of Credit") with a related party for $5.0 million. This Line of Credit was amended on November 4, 2021 to increase the total available under the Line of Credit to $5.5 million. The Line of Credit had a maturity date of February 28, 2023 and accrued interest at an annual rate of 3.5% payable quarterly. During the year ended December 31, 2021 we received proceeds and made payments under the Line of Credit of $5.3 million. On November 10, 2021 we terminated the Line of Credit.

Affiliate Coal Lease Agreements

The following table summarizes advanced royalties outstanding and related payments and recoupments under our affiliate coal lease agreements:

	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, 2019	$ —	$ 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
Payments	3,000	3,597	2,568	2,522	2,132	13,819
Recoupment	(3,000)	(1,022)	—	—	(56)	(4,078)
Unrecoupable	—	—	(2,568)	—	—	(2,568)
As of December 31, 2020	1,500	19,178	—	15,129	12,582	48,389
Payments	3,000	3,597	2,568	2,521	2,131	13,817
Recoupment	(3,000)	(1,025)	—	—	—	(4,025)
Unrecoupable	—	—	(2,568)	—	—	(2,568)
As of December 31, 2021	$ 1,500	$ 21,750	$ —	$ 17,650	$ 14,713	$ 55,613

Craft Foundations—In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease with Alliance Resource GP, LLC, an entity indirectly wholly owned by Mr. Craft and Kathleen S. Craft until it was dissolved in December 2020. In December 2018, the property subject to the lease was transferred to the Joseph W. Craft III Foundation and the Kathleen S. Craft Foundation, which each hold an undivided one-half interest (the "Craft Foundations"). 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 $5.8 million, $6.1 million and $7.2 million in earned royalties in 2021, 2020 and 2019 respectively.

WKY CoalPlay—In February 2015, WKY CoalPlay entered into a coal lease agreement with Alliance Resource Properties regarding coal mineral resources 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 mineral reserves and resources 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 coal mineral reserves and resources taking into account payments previously made under the lease. These options expired in February 2021.

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 granted Alliance Resource Properties an option to acquire the leased coal mineral reserves and resources 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 coal mineral reserves and resources taking into account payments previously made under the leases. These options expired in December 2020. (See Note 12 – 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 coal mineral resources 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 coal mineral resources taking into account payments previously made under the lease (See Note 12 – Variable Interest Entities). In the third quarter of 2019 it was determined that the balance of advanced royalties, the advance royalty payment in 2020 and 2021 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 expected 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 12 – Variable Interest Entities, through our subsidiaries, we hold a non-economic managing member interest and a 96% non-managing member interest in Cavalier Minerals and, Bluegrass Minerals, a third party, holds a 4% non-managing member interest and a profits interest. See Note 13 – Investments for information on payments made and distributions received by Cavalier Minerals.

22. 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 mineral reserve and resource leases as discussed in Note 21 – Related-Party Transactions.

Contractual Commitments—In connection with planned capital projects, we have contractual commitments of approximately $85.7 million at December 31, 2021. As of December 31, 2021, we had no commitments to purchase coal from external production sources in 2021 and thereafter.

General Litigation—We are party to litigation that has been initiated against certain of our subsidiaries in which the plaintiffs allege violations of the Fair Labor Standards Act and Kentucky Wage and Hour Act due to an alleged failure to compensate for time "donning" and "doffing" equipment and to account for certain bonuses in the calculation of overtime rates and pay. The plaintiffs seek class or collective action certification. Because the litigation of these matters is in the early stages, we cannot reasonably estimate a range of potential exposure at this time. We believe the plaintiffs' claims are without merit and our ultimate exposure, if any, will not be material to our results of operations or financial position and we intend to defend the litigation vigorously. However, if our current belief that the claims are without merit is not upheld, it is reasonably possible that the ultimate resolution of these matters could result in a potential loss that may be material to our results of operations.

We also have various other lawsuits, claims and regulatory proceedings incidental to our business that 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 are different from management's current expectations and in amounts greater than our accruals, such matters could have a material adverse effect on our business and operations.

Other—Effective December 1, 2021, 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 75 or 90 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, the insurance industry has been subject to efforts by environmental activists to restrict coverages available for fossil-fuel companies.

23. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

The international coal market has been a 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, 2021, 2020 and 2019, export tons represented approximately 12.5%, 3.3% and 17.9% of tons sold, respectively.

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, 2021, 2020 and 2019.

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	2021	2020	2019
			(in thousands)	
Customer A	Illinois Basin	$ 239,482	$ 197,379	$ 228,500
Customer B	Appalachia	—	—	213,319
Customer C	Illinois Basin	—	157,271	—
Customer D	Illinois Basin/Appalachia	—	137,785	—

Trade accounts receivable from major customers totaled approximately $10.8 million and $32.0 million at December 31, 2021 and 2020, respectively. Our credit loss experience has historically been insignificant. Financial conditions of our customers could result in a material change to our credit loss expense in future periods. The coal supply agreements with Customer A expires in 2024.

24. SEGMENT INFORMATION

We operate in the United States as a diversified natural resource company that generates operating and royalty income from the production and marketing of coal to major domestic and international utilities and industrial users as well as royalty income from oil & gas mineral interests. We aggregate multiple operating segments into four reportable segments, Illinois Basin Coal Operations, Appalachia Coal Operations, Oil & Gas Royalties and Coal Royalties. We also have an "all other" category referred to as Other, Corporate and Elimination. Our two coal operations 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 operations reportable segments include seven mining complexes operating in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia and a coal loading terminal in Indiana on the Ohio River. Our Oil & Gas Royalties reportable segment includes our oil & gas mineral interests which are located primarily in the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) basins. The operations within our Oil & Gas Royalties reportable segment primarily include receiving royalties and lease bonuses for our oil & gas mineral interests. Our Coal Royalties reportable segment includes coal mineral reserves and resources owned or leased by Alliance Resource Properties, which are either (a) leased to our mining complexes or (b) near our coal mining operations but not yet leased.

Beginning in the first quarter of 2021, we began to strategically view and manage our coal royalty activities separately from our coal operations since acquiring and managing a variety of royalty producing assets involve similar attributes. As a result, we restructured our reportable segments to better reflect this strategic view in how we manage our business and allocate resources. Prior periods have been recast to include Alliance Resource Properties within our new Coal Royalties reportable segment with offsetting recast adjustments primarily to our coal operations reportable segments and to a lesser extent, our Other, Corporate and Elimination category. Eliminations reported in Other, Corporate and Elimination were also recast to reflect intercompany royalty revenues and offsetting intercompany royalty expense resulting from our new Coal Royalties reportable segment.

The Illinois Basin Coal Operations reportable segment includes currently operating mining complexes (a) the Gibson County Coal, LLC's ("Gibson") mining complex, which includes the Gibson South mine, (b) the Warrior Coal, LLC ("Warrior") mining complex, (c) the River View Coal, LLC ("River View") mining complex and (d) the Hamilton mining complex. The Illinois Basin Coal Operations reportable segment also includes our Mt. Vernon Transfer Terminal, LLC ("Mt. Vernon") coal loading terminal in Indiana which currently operates on the Ohio River.

The Illinois Basin Coal Operations reportable segment also includes Mid-America Carbonates, LLC ("MAC") and other support services as well as non-operating mining complexes (a) Gibson North mine, which ceased production in the fourth quarter of 2019, (b) Webster County Coal, LLC's Dotiki mining complex, which ceased production in August 2019, (c) White County Coal, LLC's Pattiki mining complex, which ceased production in December 2016, (d) the Hopkins County Coal, LLC mining complex, which ceased production in April 2016, and (e) Sebree Mining, LLC's mining complex, which ceased production in November 2015.

The Appalachia Coal Operations reportable segment includes currently operating mining complexes (a) the Mettiki mining complex, (b) the Tunnel Ridge mining complex and (c) the MC Mining, LLC ("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 Oil & Gas Royalties 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 13 – Investments) and Cavalier Minerals. AR Midland acquired its mineral interest in the Wing Acquisition and Boulders Acquisition (Note 3 – Acquisitions).

Coal Royalties reportable segment includes coal mineral reserves and resources owned or leased by Alliance Resource Properties that are (a) leased to certain of our mining complexes in both the Illinois Basin Coal Operations and Appalachia Coal Operations reportable segments or (b) located near our operations and external mining operations. Approximately two thirds of the coal sold by our Coal Operations' mines is leased from our Coal Royalties entities.

Other, Corporate and Elimination 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"), Pontiki Coal, LLC's workers' compensation and pneumoconiosis liabilities, Wildcat Insurance, which assists the ARLP Partnership with its insurance requirements, AROP Funding and Alliance Finance (both discussed in Note 8 – Long-Term Debt) and other miscellaneous activities. The eliminations included in Other, Corporate and Elimination primarily represent the intercompany coal royalty transactions described above between our Coal Royalties reportable segment and our coal operations' mines.

Reportable segment results are presented below.

	Coal Operations		Royalties			
	Illinois Basin	Appalachia	Oil & Gas	Coal	Other, Corporate and Elimination	Consolidated
			(in thousands)			
Year Ended December 31, 2021						
Revenues - Outside	$ 919,597	$ 545,539	$ 77,185	$ 69	$ 27,586	$ 1,569,976
Revenues - Intercompany	—	—	—	51,402	(51,402)	—
Total revenues (1)	919,597	545,539	77,185	51,471	(23,816)	1,569,976
Segment Adjusted EBITDA Expense (2)	613,303	344,332	9,943	18,269	(33,198)	952,649
Segment Adjusted EBITDA (3)	265,292	172,601	68,774	33,202	9,383	549,252
Total assets	676,091	420,144	630,627	285,943	146,601	2,159,406
Capital expenditures (4)	60,166	47,577	—	45	15,196	122,984
Year Ended December 31, 2020						
Revenues - Outside	$ 769,957	$ 500,330	$ 43,141	$ 105	$ 14,596	$ 1,328,129
Revenues - Intercompany	—	—	—	42,112	(42,112)	—
Total revenues (1)	769,957	500,330	43,141	42,217	(27,516)	1,328,129
Segment Adjusted EBITDA Expense (2)	543,264	320,656	4,106	18,249	(25,026)	861,249
Segment Adjusted EBITDA (3)	213,876	171,362	39,773	23,968	(2,490)	446,489
Total assets	738,315	440,815	613,916	288,525	84,445	2,166,016
Capital expenditures	48,636	70,960	—	12	1,493	121,101
Year Ended December 31, 2019						
Revenues - Outside	$ 1,219,601	$ 644,389	$ 53,036	$ 23	$ 44,671	$ 1,961,720
Revenues - Intercompany	16,690	—	—	57,737	(74,427)	—
Total revenues (1)	1,236,291	644,389	53,036	57,760	(29,756)	1,961,720
Segment Adjusted EBITDA Expense (2)	791,795	424,387	7,811	21,445	(40,542)	1,204,896
Segment Adjusted EBITDA (3)	349,810	215,187	46,997	36,315	23,692	672,001
Total assets	1,092,188	489,378	643,213	292,436	69,479	2,586,694
Capital expenditures (4)	188,928	111,729	—	352	4,849	305,858

(1) Revenues included in the Other, Corporate and Elimination column are attributable to intercompany eliminations, which are primarily the coal royalties intercompany eliminations, outside revenues at the Matrix Group and other outside miscellaneous sales and revenue activities.

(2) 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,		
	2021	2020	2019
		(in thousands)	
Segment Adjusted EBITDA Expense	$ 952,649	$ 861,249	$ 1,204,896
Outside coal purchases	(6,372)	—	(23,357)
Other income (expense)	(3,020)	(1,593)	561
Operating expenses (excluding depreciation, depletion and amortization)	$ 943,257	$ 859,656	$ 1,182,100

(3) Segment Adjusted EBITDA is defined as net income (loss) attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization, general and administrative expense, asset and goodwill impairments 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 (loss) as follows:

	Year Ended December 31,		
	2021	**2020**	**2019**
		(in thousands)	
Consolidated Segment Adjusted EBITDA	$ 549,252	$ 446,489	$ 672,001
General and administrative	(70,160)	(59,806)	(72,997)
Depreciation, depletion and amortization	(261,377)	(313,387)	(309,075)
Asset impairments	—	(24,977)	(15,190)
Goodwill impairment	—	(132,026)	—
Interest expense, net	(39,141)	(45,478)	(45,496)
Acquisition gain	—	—	177,043
Income tax (expense) benefit	(417)	(35)	211
Acquisition gain attributable to noncontrolling interest	—	—	(7,083)
Net income (loss) attributable to ARLP	$ 178,157	$ (129,220)	$ 399,414
Noncontrolling interest	598	169	7,512
Net income (loss)	$ 178,755	$ (129,051)	$ 406,926

(4) Capital Expenditures shown exclude the AllDale Acquisition on January 3, 2019, the Wing Acquisition on August 2, 2019 and Boulders Acquisition on October 13, 2021 (Note 3 – Acquisitions).

25. SUBSEQUENT EVENTS

Other than the events described in Notes 8, 11 and 17, there were no subsequent events.

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. Subsequent to our 2019 acquisitions of oil and gas mineral interests, we are considered to have significant oil & gas producing activities.

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,		
	2021	2020	2019
		(in thousands)	
Acquisition costs of properties			
Proved	$ 12,542	$ —	$ 242,116
Unproved	18,419	—	376,166
Total	$ 30,961	$ —	$ 618,282

Property acquisition costs for 2021 are related to the Boulders Acquisition. Property acquisition costs for 2019 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 regarding these acquisitions.

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,			
	2021		2020	
	(in thousands)			
	Consolidated	Our Share of an Equity Method Investee	Consolidated	Our Share of an Equity Method Investee
Proved properties	$ 289,378	$ 9,138	$ 273,665	$ 8,331
Unproved properties	358,486	19,216	343,239	20,287
Total (1)	647,864	28,354	616,904	28,618
Less accumulated depreciation, depletion and amortization	(70,286)	(3,015)	(48,019)	(1,985)
Oil & gas properties, net	$ 577,578	$ 25,339	$ 568,885	$ 26,633

(1) The change in total capitalized cost in 2021 reflects the acquisition of proved and unproved properties in the Boulders Acquisition. See Note 3 – Acquisitions of our consolidated financial statements for more information about the Boulders Acquisition.

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 Oil & Gas Royalties segment.

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Consolidated activities			
Oil & gas royalties	$ 74,988	$ 42,912	$ 51,735
Other revenues	2,197	229	1,301
Production costs and severance taxes	(7,396)	(4,611)	(7,859)
Depreciation, depletion and amortization	(22,267)	(25,376)	(22,658)
Total results of oil & gas activities	$ 47,522	$ 13,154	$ 22,519
Our share of an equity method investee			
Oil & gas royalties	$ 3,788	$ 2,674	$ 3,200
Other revenues	66	22	190
Production costs and severance taxes	(472)	(374)	(411)
Depreciation, depletion and amortization	(787)	(748)	(854)
Total results of oil & gas activities	$ 2,595	$ 1,574	$ 2,125

Oil & Gas Reserves

Proved oil & gas reserve estimates as of December 31, 2021 were prepared by our internal engineering team and 95% of those reserves were audited 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:

Consolidated activities	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
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
Revisions of previous estimates	(194)	2,679	343	596
Extensions and discoveries	1,095	3,039	347	1,949
Production	(905)	(3,301)	(337)	(1,792)
Sales of minerals in place	(18)	(29)	(3)	(26)
As of December 31, 2020 (1)	6,802	31,017	2,932	14,904
Purchases of minerals in place	287	2,149	332	977
Revisions of previous estimates	(403)	(90)	197	(221)
Extensions and discoveries	629	159	335	991
Production	(794)	(3,069)	(357)	(1,663)
As of December 31, 2021 (1)	6,521	30,166	3,439	14,988

(1) Proved reserves of approximately 1,285 MBOE, 972 MBOE and 1,208 MBOE were attributable to noncontrolling interests, as of December 31, 2021, 2020 and 2019, respectively.

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 minerals in place	(7)	(8)	—	(8)
Production	(41)	(282)	(17)	(105)
As of December 31, 2019	325	1,926	136	783
Revisions of previous estimates	—	(1)	(2)	(3)
Extensions and discoveries	62	461	54	193
Production	(44)	(334)	—	(100)
As of December 31, 2020	342	2,052	188	873
Sales of minerals in place	(9)	(15)	—	(12)
Revisions of previous estimates	(50)	320	(53)	(51)
Extensions and discoveries	73	450	43	190
Production	(31)	(421)	—	(101)
As of December 31, 2021	325	2,386	178	899
Total consolidated and equity interests in reserves at December 31, 2021	6,846	32,552	3,617	15,887
Net proved developed reserves as of December 31, 2019	5,766	24,449	2,009	11,850
Net proved developed reserves as of December 31, 2020	5,073	23,504	2,252	11,244
Net proved developed reserves as of December 31, 2021	5,493	28,426	3,039	13,269
Net proved undeveloped reserves as of December 31, 2019	1,383	6,106	709	3,110
Net proved undeveloped reserves as of December 31, 2020	2,071	9,565	868	4,533
Net proved undeveloped reserves as of December 31, 2021	1,353	4,126	578	2,618

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.

Notable changes in proved reserves during the year ended December 31, 2020, included:

- *Net change due to extensions and discoveries:* The increases are a result of the addition of new properties by the operators under which we own mineral interests. In 2020, a net addition of 2,142 MBOE occurred primarily from the completion of 655 new wells on our acreage and from the addition of 877 new proved undeveloped locations due to permitting and drilling activity.

- *Revisions:* Increases in oil & gas are also due to changes in the underlying commodity prices during the year and revisions of previous quantity estimates.

Notable changes in proved reserves during the year ended December 31, 2021, included:

- *Net change due to extensions and discoveries:* The increases are a result of the addition of new properties by the operators under which we own mineral interests. In 2021, a net addition of 1,181 MBOE occurred primarily from the completion of 843 new wells on our acreage and from the addition of 474 new proved undeveloped locations due to permitting and drilling activity.

- *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, 2021. 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,					
	2021		2020		2019	
	(in thousands)					
	Consolidated	Our Share of an Equity Method Investee	Consolidated	Our Share of an Equity Method Investee	Consolidated	Our Share of an Equity Method Investee
Future cash inflows	$ 577,114	$ 31,636	$ 302,112	$ 15,414	$ 463,972	$ 24,372
Future production costs and severance taxes	(43,474)	(2,484)	(21,555)	(1,244)	(34,997)	(1,515)
Future net cash flows (undiscounted)	533,640	29,152	280,557	14,170	428,975	22,857
Annual discount 10% for estimated timing	(260,718)	(13,980)	(130,341)	(6,406)	(198,025)	(10,642)
Total standardized measure (1)	$ 272,922	$ 15,172	$ 150,216	$ 7,764	$ 230,950	$ 12,215

(1) Includes standardized discounted future net cash flows of approximately $17.9 million, $5.2 million and $12.5 million attributable to noncontrolling interests in the ARLP Partnership's consolidated subsidiaries as of December 31, 2021, 2020 and 2019, respectively.

The average realized product prices weighted by production over the remaining lives of the properties are presented in the table below:

	For the Year Ended December 31,		
	2021	2020	2019
Oil (per Bbl)	$ 63.57	$ 36.95	$ 52.32
Natural gas (per Mcf)	2.98	0.88	1.83
NGLs (per Bbl)	21.13	7.99	21.95

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, (in thousands)					
	2021		2020		2019	
	Consolidated	Our Share of an Equity Method Investee	Consolidated	Our Share of an Equity Method Investee	Consolidated	Our Share of an Equity Method Investee
Standardized measure, beginning of year	$ 150,216	$ 7,764	$ 230,950	$ 12,215	$ —	$ 12,845
Purchases and sales of reserves in place, less related costs	15,358	(264)	(567)	—	231,287	(252)
Sales, net of production costs	(67,592)	(3,316)	(38,301)	(2,300)	(43,875)	(2,788)
Net changes due to extensions and discoveries	34,284	3,613	15,770	1,344	—	—
Net changes in prices and production costs	120,103	6,753	(67,524)	(3,906)	10,533	(2,517)
Revisions of previous quantity estimates	8,310	(871)	(2,843)	(378)	14,560	3,398
Accretion of discount	11,745	545	16,216	870	18,403	1,284
Changes in timing and other	498	948	(3,485)	(81)	42	245
Net increase (decrease) in standardized measures	122,706	7,408	(80,734)	(4,451)	230,950	(630)
Standardized measure, end of year	$ 272,922	$ 15,172	$ 150,216	$ 7,764	$ 230,950	$ 12,215

Net change in prices and production costs occur from one reporting period to another when the SEC reporting price for that period changes. For 2021, this was a major component of the overall reserves value change from 2020 due to the surge in global energy demand during the recovery from the economic downturn related to the COVID-19 pandemic during 2020. For 2020, net changes in prices and production costs were major components of the overall reserves value change from 2019 due mainly to the COVID-19 pandemic and the subsequent decline in oil and gas demand.

The standardized measure amount at the beginning of 2019 for 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 in 2019, 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 I – CONDENSED FINANCIAL INFORMATION OF REGISTRANT
ALLIANCE RESOURCE PARTNERS, L.P.

CONDENSED BALANCE SHEETS (PARENT)
DECEMBER 31, 2021 AND 2020
(In thousands, except unit data)

	December 31, 2021	December 31, 2020
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,173	$ 2,174
Total current assets	2,173	2,174
OTHER ASSETS:		
Investments in consolidated subsidiaries	1,277,110	1,146,491
Total other assets	1,277,110	1,146,491
TOTAL ASSETS	$ 1,279,283	$ 1,148,665
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accrued taxes other than income taxes	$ 100	$ 100
Total current liabilities	100	100
Total liabilities	100	100
PARTNERS' CAPITAL:		
Limited Partners - Common Unitholders 127,195,219 units outstanding	1,279,183	1,148,565
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,279,283	$ 1,148,665

See accompanying notes.

CONDENSED STATEMENTS OF OPERATIONS (PARENT)
FOR THE YEARS ENDED DECEMBER 31, 2021, 2020 AND 2019
(In thousands, except unit and per unit data)

	Year Ended December 31, 2021	2020	2019
EXPENSES:			
General and administrative	$ —	$ —	$ 41
Total operating expenses	—	—	41
INCOME (LOSS) FROM OPERATIONS	—	—	(41)
Interest income	—	24	34
Equity in earnings of consolidated subsidiaries	178,157	(129,244)	399,421
NET INCOME (LOSS) ATTRIBUTABLE TO ARLP	$ 178,157	$ (129,220)	$ 399,414
EARNINGS PER LIMITED PARTNER UNIT - BASIC AND DILUTED	$ 1.36	$ (1.02)	$ 3.07
WEIGHTED-AVERAGE NUMBER OF UNITS OUTSTANDING – BASIC AND DILUTED	127,195,219	127,164,659	128,116,670

See accompanying notes.

CONDENSED STATEMENTS OF CASH FLOWS (PARENT)
FOR THE YEARS ENDED DECEMBER 31, 2021, 2020 AND 2019
(In thousands)

	Year Ended December 31,		
	2021	**2020**	**2019**
CASH FLOWS FROM OPERATING ACTIVITIES:	$ 52,157	$ 51,751	$ 278,308
CASH FLOWS FROM FINANCING ACTIVITIES:			
Distributions paid to Partners	(52,158)	(51,753)	(278,425)
Net cash used in financing activities	(52,158)	(51,753)	(278,425)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(1)	(2)	(117)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2,174	2,176	2,293
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 2,173	$ 2,174	$ 2,176

See accompanying notes.

NOTES TO FINANCIAL INFORMATION (PARENT)

1. BASIS OF PRESENTATION

In these parent-company-only financial statements, our investment in consolidated subsidiaries is stated at cost plus equity in undistributed earnings of subsidiaries and reduced by distributions received from subsidiaries since the date of acquisition. These parent-company-only financial statements should be read in conjunction with our consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

2. GUARANTEES

As the parent of the Intermediate Partnership, we are a guarantor of both the Credit Agreement and Senior Notes discussed in "Item 8. Financial Statements and Supplementary Data—Note 8 – Long-Term Debt" of this Annual Report on Form 10-K. In addition to these guarantees, we have provided guarantees on surety indemnity agreements and financially guaranteed certain coal supply agreements. The duration of these guarantees varies. The maximum undiscounted potential future payment obligation for our guarantees of certain coal supply agreements as of December 31, 2021 is approximately $146.7 million as a result of elevated market prices. These guarantees provide for compensation to customers based on additional cost to the customer to replace any contracted tons that our subsidiaries fail to deliver. We do not expect to make any payments under these guarantees.

3. CASH DISTRIBUTIONS RECEIVED

We received distributions of $52.2 million, $51.8 million and $278.4 million from our consolidated subsidiaries during the years ended December 31, 2021, 2020, and 2019, respectively.

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 Securities Exchange Act of 1934 ("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, 2021. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures are effective as of December 31, 2021.

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, 2021 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, 2021. 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, 2021, 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.

Grant Thornton 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, 2021, as stated in their report that is included herein.

Changes in Internal Controls Over Financial Reporting. 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, 2021 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

During the three month period ended June 30, 2021, we discovered that certain of our computer systems were subject to a cyber incident that did not materially impact our business, financial position or results of operations. We took appropriate steps in response to the incident, including providing individual notifications. Because of this incident and the recent focus nationally on increases in ransomware attacks and other cybersecurity incidents on critical infrastructure, we implemented two-factor authentication and other security enhancements for access to our internal network as well as improvements to our network backup and recovery processes. We do not consider these changes to our information technology environment, under which many of our internal controls operate, to be material changes in our internal control over financial reporting, but expect that these changes will strengthen our overall system of internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Alliance Resource Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2021, and our report dated February 25, 2022 expressed an unqualified opinion on those financial statements.

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/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 25, 2022

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	71	Chairman, President and Chief Executive Officer
Brian L. Cantrell	62	Senior Vice President and Chief Financial Officer
R. Eberley Davis	64	Senior Vice President, General Counsel and Secretary
Robert J. Fouch	64	Vice President, Controller and Chief Accounting Officer
Robert G. Sachse	73	Executive Vice President
Kirk D. Tholen	49	Senior Vice President; also President, Alliance Minerals, LLC
Timothy J. Whelan	59	Senior Vice President - Sales and Marketing of Alliance Coal, LLC
Thomas M. Wynne	65	Senior Vice President and Chief Operating Officer
Nick Carter	75	Director and Member of Audit, Compensation and Conflicts Committees
Robert J. Druten	74	Director and Member of Audit, Compensation and Conflicts* Committees
John H. Robinson	71	Director and Member of Audit, Compensation* and Conflicts Committees
Wilson M. Torrence	80	Director and Member of Audit* and Compensation Committees

* Indicates Chairman of Committee.

Joseph W. Craft III has been President, Chief Executive Officer ("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 Director of the National Mining Association, and a Director and former Chairman of America's Power. Mr. Craft is a Director and former Chairman of the Kentucky 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 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.

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 previously served on the board of directors, the audit committee and as chairman of the compensation committee of Community Trust Bancorp, Inc. (NASDAQ: CTBI). Mr. Carter also previously served as chairman of the National Council of Coal Lessors for 12 years, as chairman of the West Virginia Chamber of Commerce, and 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 Alliance Holdings GP, L.P. ("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 previously served as Chairman of the Board of Directors of Kansas City Southern Industries, Inc. (NYSE: KSU), a transportation and financial services company, and was Chairman of its executive committee and a member of its compensation committee and nominating and governance committees, and now serves as a trustee of the voting trust holding KSU pending the Surface Transportation Board's review and approval of KSU's recent combination with Canadian Pacific Railway Limited. 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 industries, 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 or, in the case of Mr. Fouch, the CFO, 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 of 1933 ("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 nine times during 2021. 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, 2021, (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. A copy of the Audit Committee charter 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. 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, Grant Thornton LLP ("Grant Thornton"), is responsible for expressing an opinion on the conformity of the audited financial statements with GAAP. The Audit Committee reviewed with Grant Thornton 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 Grant Thornton required by applicable requirements of the PCAOB Rule 3526, "Communication with Audit Committees Concerning Independence," and has discussed with Grant Thornton 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, 2021 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 Chief Accounting Officer, 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, other than as described below, during 2021 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), with the following exceptions: on March 8, 2021 ARLP units owned by Alliance Resource GP, LLC, an entity owned jointly by Mr. Craft and Kathleen S. Craft, were distributed to Mr. Craft and Mrs. Craft individually, and the Form 4s for such distribution inadvertently were not filed until April 19, 2021.

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 2021, 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 three key objectives: (i) provide a competitive compensation opportunity to allow us to recruit and retain key management talent, (ii) align executive officers' interests with unitholder interests and (iii) motivate and reward the executive officers for creating sustainable, capital-efficient growth in available cash to maximize unitholder returns. 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, 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. Mr. Tholen also serves as the President of Alliance Minerals, LLC. The Tholen Employment Letter provides for, among other things, (i) an initial annual base salary of $500,000, (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 in three cash installments of $500,000 each 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 short-term incentive plan ("STIP"), 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 filed as an exhibit to this filing.

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 2021, 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 2021 included Alpha Metallurgical Resources, Inc., Arch Resources, Inc., Consol Energy, Inc., Natural Resource Partners L.P., Peabody Energy Corporation and Warrior Met Coal, Inc. In assessing the competitiveness of our executive compensation program for 2021, 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 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 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 Supplemental Executive Retirement Plan ("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. None of our Named Executive Officers received an increase in salary in 2021.

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 businesses. (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. Our STIP Guidelines provide that achieving the minimum threshold is the minimum acceptable result for a performance pay-out to occur under the STIP, although the Compensation Committee may determine satisfactory results and adjust the size of the pay-out pool in its sole discretion. In 2021, the

Compensation Committee approved a minimum financial performance target of $371.1 million in EBITDA from current operations, normalized by excluding any charges for unit-based and directors' compensation. For 2021, we exceeded the minimum performance target.

Individual 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 2022 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 2022 will be reasonably difficult to achieve and therefore support our key compensation objectives discussed above.

The Compensation Committee maintains discretion to grant cash bonus awards outside of the STIP to address special situations.

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, (b) options to purchase common units (although to date, no grants of options have been made) or c) cash awards. 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 2021 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, 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 vesting 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, although grants for 2021 were not made until April, 2021. The compensation expense associated with LTIP grants is recognized over the vesting period in accordance with 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.

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.

Grants for 2021 under the LTIP, made April 22, 2021, will cliff vest on January 1, 2024, 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, 2021 through December 31, 2023. Regardless of achieving the EBITDA target, the 2021 grants have a minimum value guarantee of either $2.53 or $3.79 per unit. Grants for 2022 under the LTIP, made January 26, 2022, will cliff vest on January 1, 2025, 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, 2022 through December 31, 2024. Regardless of achieving the EBITDA target, the 2022 grants have a minimum value guarantee of either $9.62 or $6.41 per unit. 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

Securities Trading Policy; Prohibitions on Hedging and Trading in Derivatives

To ensure alignment of the interests of our unitholders with our directors and all officers, including Named Executive Officers, the general partner's Securities Trading Policy prohibits any employee, officer, or director of the Partnership or any of its subsidiaries from engaging in trading involving (1) options or other derivative securities relating to ARLP units; (2) debt securities of ARLP or its affiliates; (3) hedging transactions involving ARLP securities; or (4) purchases of ARLP units on margin.

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 annual physical medical exams, 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, 2021.

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	Bonus (1)	Unit Awards (2)(3)	Non-Equity Incentive Plan Compensation (4)	All Other Compensation (5)	Total
Joseph W. Craft III	2021	$ 1	$ —	$ —	$ —	$ —	$ 1
President, Chief Executive	2020	1	—	—	—	—	1
Officer and Chairman	2019	1	—	—	—	12,962	12,963
Brian L. Cantrell,	2021	309,846	—	567,182	250,000	30,443	1,157,471
Senior Vice President and	2020	309,846	289,513	756,965	—	181,843	1,538,167
Chief Financial Officer	2019	299,846	—	529,161	213,000	66,612	1,108,619
R. Eberley Davis	2021	351,635	—	722,394	365,000	41,768	1,480,797
Senior Vice President,	2020	351,635	377,249	964,133	—	248,531	1,941,548
General Counsel and Secretary	2019	341,154	—	673,993	274,000	86,768	1,375,915
Kirk D. Tholen	2021	509,615	500,000	1,194,061	540,000	152,688	2,896,364
Senior Vice President; also	2020	500,000	500,000	862,779	500,000	421,764	2,784,543
President Alliance Minerals, LLC	2019	—	500,000	1,016,237	83,000	69,978	1,669,215
Thomas M. Wynne	2021	411,769	—	835,818	400,000	43,588	1,691,175
Senior Vice President and	2020	411,769	391,899	1,114,122	—	267,645	2,185,435
Chief Operating Officer	2019	398,231	—	774,261	280,000	80,287	1,532,779

(1) The amounts for Messrs. Cantrell, Davis and Wynne represent cash bonuses paid in December 2020. The amounts for Mr. Tholen represent the three installments 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.

(2) Restricted units granted in February 2020 were determined to be improbable of vesting and amended during the fourth quarter of 2020 for all LTIP participants other than Mr. Tholen, including Messrs. Cantrell, Davis and Wynne. The amendments modified the performance vesting requirement and granted additional restricted units. The modified performance vesting requirement makes it probable the awards will vest. As a result, the amounts for 2020 for Messrs. Cantrell, Davis, and Wynne include $409,822, $521,981 and $603,944, respectively, representing the grant date fair value of the restricted units when originally granted in February 2020, and $213,857, $272,385 and $315,156, respectively, representing the fair value of the same restricted units at the date of modification in December 2020. The fair value of the modified awards was calculated by taking the fair value of the modified awards at the date of modification minus the fair value of the original awards immediately prior to modification. Since the original awards granted in February 2020 were determined to be improbable of vesting, the fair value of the original awards immediately prior to modification was zero. The 2020 amounts also include the grant date fair value of the additional restricted units granted in December 2020. The grants include a minimum value guarantee. For Mr. Tholen, the 2020 amount represents the grant date fair value of the restricted units when originally granted in February 2020. The restricted units granted to Mr. Tholen in February 2020 (as well as the restricted units granted to him in 2019) were canceled in December 2020 and replaced with a cash service award that is payable one-half in February 2022 and one-half in February 2023. Mr. Craft did not receive any grants under the LTIP during 2020.

(3) Other than the restricted units which were modified in December 2020 and discussed in footnote (2) above, the Unit Awards represent the aggregate grant date fair value of restricted units granted pursuant to FASB ASC 718, using the same assumptions as used for financial reporting purposes and which are more fully described in "Item 8. Financial Statements and Supplementary Data—Note 17 – Common Unit-Based Compensation Plans," to each Named Executive Officer under the LTIP in the respective year. The restricted units that were granted in 2018 were settled in cash at $4.99 per unit in December 2020. The cash settlement is included in "All Other Compensation" in 2020. The restricted units that were granted in 2019 were canceled in December 2020 since it was determined that the vesting requirements for these restricted units were not probable of being satisfied. 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 typically are made in the first quarter of the year following the year in which they are earned, however the STIP payment to Mr. Tholen in 2020 was made

in December 2020. 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. In addition, the amounts for 2020 include cash settlement in December 2020 of restricted units that were granted under the LTIP in 2018. A reconciliation of the 2021 amounts is as follows:

	SERP	Profit Sharing Plan Employer Contribution	Perquisites (a)	Total
Joseph W. Craft III	$ —	$ —	$ —	$ —
Brian L. Cantrell	7,243	23,200	—	30,443
R. Eberley Davis	18,568	23,200	—	41,768
Kirk D. Tholen	91,514	23,200	37,974	152,688
Thomas M. Wynne	20,388	23,200	—	43,588

a) For Mr. Tholen, perquisites and other personal benefits comprised of relocation related expenses of $37,834 and tax preparation fees of $140.

Grants of Plan-Based Awards Table

Name	Grant Date	Approved Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold (3)	Target (4)	Maximum (3)	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (5)	Target (6)	Maximum (5)	All Other Unit Awards: Number of Units (7)	Grant Date Fair Value of Unit Awards (8)
Joseph W. Craft III	May 14, 2021	(1), (2)							4,785	29,284
	August 13, 2021	(1), (2)							3,636	29,633
	November 12, 2021	(1), (2)							5,062	55,125
									13,483	114,042
Brian L. Cantrell	April 27, 2021	April 27, 2021					94,060		—	567,182
	May 14, 2021	(1), (2)					—		688	4,211
	August 13, 2021	(1), (2)					—		523	4,262
	November 12, 2021	(1), (2)					—		728	7,928
	December 31, 2021	(2)					—		573	7,243
	January 27, 2021	January 19, 2022		250,000			—		—	—
				250,000			94,060		2,512	590,826
R. Eberley Davis	April 27, 2021	April 27, 2021					119,800		—	722,394
	May 14, 2021	(1), (2)					—		1,034	6,328
	August 13, 2021	(1), (2)					—		786	6,406
	November 12, 2021	(1), (2)					—		1,094	11,914
	December 31, 2021	(2)					—		1,469	18,568
	January 27, 2021	January 19, 2022		365,000			—		—	—
				365,000			119,800		4,383	765,610
Kirk D. Tholen	April 27, 2021	April 27, 2021					198,020		—	1,194,061
	May 14, 2021	(1), (2)					—		614	3,758
	August 13, 2021	(1), (2)					—		466	3,798
	November 12, 2021	(1), (2)					—		649	7,068
	December 31, 2021	(2)					—		7,240	91,514
	January 27, 2021	January 19, 2022		540,000			—		—	—
				540,000			198,020		8,969	1,300,199
Thomas M. Wynne	April 27, 2021	April 27, 2021					138,610		—	835,818
	May 14, 2021	(1), (2)					—		1,030	6,304
	August 13, 2021	(1), (2)					—		783	6,381
	November 12, 2021	(1), (2)					—		1,089	11,859
	December 31, 2021	(2)					—		1,613	20,388
	January 27, 2021	January 19, 2022		400,000			—		—	—
				400,000			138,610		4,515	$ 880,750

(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 the STIP are subject to our achieving an annual 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 27, 2021, the Compensation Committee set the EBITDA target amount for use in determining the total plan payout for 2021. 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 generally 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. The grants include a minimum value guarantee. 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. The grants include a minimum value guarantee. 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 granted on April 27, 2021 to our Named Executive Officers using a value of $6.03 per unit, the closing unit price on the grant date. 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. The Compensation Committee maintains discretion to grant cash bonus awards outside of the STIP to address special situations. 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, (b) options to purchase common units, although to date, no grants of options have been made, and (c) cash awards. 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. The grants include a minimum value guarantee. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*."

During the first quarter of 2020, it was determined the vesting performance requirement with respect to the restricted units granted under the LTIP on January 23, 2019 (the "2019 Grants") was not probable of being satisfied, and previously recognized expense for the 2019 Grants was reversed. During the fourth quarter of 2020, it was determined the vesting performance requirement with respect to the restricted units granted under the LTIP on January 22, 2020 (the "2020 Grants") was not probable of being satisfied, and previously recognized expense for the 2020 Grants was reversed. In December 2020, the 2019 Grants to all participants were canceled, the 2020 Grant to Mr. Tholen was canceled, and the Compensation Committee approved amending the terms of the 2020 Grants to participants other than Mr. Tholen. The amendments to the 2020 Grants revised the vesting performance requirement and increased the number of restricted units granted under the amended 2020 Grants. The amended 2020 Grants will vest on January 1, 2023, subject to the satisfaction of the vesting requirements.

In addition, in 2020 the Compensation Committee approved new 2020 service-based vesting LTIP awards. These awards are denominated in cash and payable 75% in February 2022 and 25% in February 2023 for all participants other than Mr. Tholen. The restricted units granted to Mr. Tholen in February 2020 and in 2019 were cancelled in December 2020 and replaced with a service-based vesting award denominated in cash and payable one-half in February 2022 and one-half in February 2023. The only condition of these service-based vesting awards is that the participant remain employed at the time of payment.

As with the bonus awards above, these LTIP actions were taken by the Compensation Committee in recognition of the difficulty of managing our business through the unprecedented impacts of the COVID-19 pandemic and based on its determination that such actions were prudent and necessary to help retain and motivate our management team.

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	2021	$ 1	$ 1	100.0%
Brian L. Cantrell	2021	309,846	1,157,471	26.8%
R. Eberley Davis	2021	351,635	1,480,797	23.7%
Kirk D. Tholen	2021	1,009,615	2,896,364	34.9%
Thomas M. Wynne	2021	411,769	1,691,175	24.3%

(1) Percentages were calculated using the base salary and discretionary bonus of the Named Executive Officers. The only discretionary bonus we provided in 2021 to our Named Executive Officers were to Mr. Tholen. 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 2021 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	163,212	2,062,999
R. Eberley Davis	207,878	2,627,578
Kirk D. Tholen	198,020	2,502,973
Thomas M. Wynne	240,239	3,036,621

(1) Amounts represent restricted units awarded under the LTIP that were not vested as of December 31, 2021. Subject to our achieving financial performance targets, these units will vest as follows:

	January 1,	
Name	2023	2024
Joseph W. Craft III	—	—
Brian L. Cantrell	69,152	94,060
R. Eberley Davis	88,078	119,800
Kirk D. Tholen	—	198,020
Thomas M. Wynne	101,629	138,610

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 $12.64 per unit, the closing price of our common units on December 31, 2021, the final market trading day of 2021.

Units Vested for 2021

Our Named Executive Officers did not have any restricted units granted under the LTIP that vested during 2021. For more information on the LTIP, please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*."

Nonqualified Deferred Compensation Table for 2021

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	$ —	$ —	$ 2,466,208	$ —	$ 3,726,639
Brian L. Cantrell	—	7,243	354,295	—	542,597
R. Eberley Davis	—	18,568	532,782	—	823,635
Kirk D. Tholen	—	91,514	315,998	—	569,002
Thomas M. Wynne	—	20,388	530,476	—	821,967

(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 2021 year.

(3) Amounts represent earnings accrued during 2021 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. The market value of the notional account balance at the end of 2021 and 2020 was $12.64 and $4.48 per common unit, respectively. Earnings were not above-market or preferential.

(4) Amounts represent the Named Executive Officer's cumulative notional account balance of phantom units valued at $12.64, the closing price of our common units on December 31, 2021, the final market trading day of 2021. 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, $391,227; Mr. Davis, $626,766; Mr. Tholen; $281,148; and Mr. Wynne, $548,021. These amounts contributed since inception, other than the amounts contributed in the last fiscal year, were previously reported as compensation in the Summary Compensation Table in previous years.

Narrative Discussion Relating to the Nonqualified Deferred Compensation Table for 2021

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 2021" 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 2021 Fiscal Year End Table", in each case assuming the triggering event occurred on December 31, 2021. 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, which as of December 31, 2021 would equal $2,000,000.

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 Compensation Committee with the concurrence of Mr. Craft, who indirectly owns our general partner. Mr. Craft, our only employee director, received no director compensation for 2021, 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 2021

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	$ 176,000	$ 4,621	$ —	$ —	$ —	$ —	$ 180,621
John H. Robinson	176,000	—	—	—	—	—	176,000
Wilson M. Torrence	196,000	3,795	—	—	—	—	199,795
Nick Carter	166,000	—	—	—	—	—	166,000

(1) Columns are not applicable.

(2) Amounts represent the grant date fair value of equity awards in 2021 related to deferrals of distributions earned on deferred units (computed pursuant to FASB ASC 718, using the same assumptions as used for financial reporting purposes and which are more fully described in "Item 8. Financial Statements and Supplementary Data—Note 17 – Common Unit-Based Compensation Plans"). Please see *Narrative to Director Compensation Table*, below.

(3) At December 31, 2021, 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	11,931
John H. Robinson	—
Wilson M. Torrence	9,793
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 2021 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. No director elected to defer cash compensation in 2021.

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.

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 2021, our last completed fiscal year:

- The median of the annual total compensation of all employees of our company (other than the CEO) was $71,753.
- The annual total compensation of our CEO, as reported in the Summary Compensation Table was $1.
- Based on this information, for 2021 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 0.00001 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 2020, we combined all of the elements of such employee's compensation for the 2021 year in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in annual total compensation of $71,753, comprised of such employee's W-2 compensation of $65,548 and contributions in the amount of $6,205 that we made on the employee's behalf to our 401(k) plan for the 2021 year.
- With respect to the annual total compensation of our CEO, we used the amount reported in the "Total" column of our 2021 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 2, 2022, 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 2, 2022.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Directors and Executive Officers		
Joseph W. Craft III (1)	19,488,253	15.3%
Nick Carter	20,000	*
Robert J. Druten	25,628	*
John H. Robinson	7,462	*
Wilson M. Torrence	40,396	*
Brian L. Cantrell	189,332	*
R. Eberley Davis	140,146	*
Robert J. Fouch	46,318	*
Robert G. Sachse	203,736	*
Kirk D. Tholen	—	*
Timothy J. Whelan	65,601	*
Thomas M. Wynne (2)	1,146,709	*
All directors and executive officers as a group (13 persons)	21,373,581	16.8%
5% Common Unit Holder		
Kathleen S. Craft	16,223,539	12.8%

* Less than one percent.

(1) The common units attributable to Mr. Craft consist of (i) 19,319,651 common units held directly by him and (ii) 168,602 common units attributable to Mr. Craft's spouse.

(2) 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.

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, 2021	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, 2021 (1)
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	3,130,475	N/A	26,485
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	646,974	N/A	N/A
Directors' Deferred Compensation	21,724	N/A	N/A

(1) We believe that we have sufficient capacity under our compensation plan to cover granted awards after consideration of future forfeitures and expected tax withholdings.

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 11 — Partners' Capital and Note 21 — Related-Party Transactions," ARLP has the following additional related-party 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, which holds a non-economic general partner interest in ARLP, 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 and AGP. Under the Administrative Services Agreement, certain employees, including some executive officers, provided administrative services for AGP and its 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, 2021. 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 $0.06 million for the year ended December 31, 2021 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 $0.1 million for the year ended December 31, 2021 for use of the aircraft.

Effective August 1, 2013, Alliance Coal entered into an expense reimbursement agreement with JC Land regarding pilots employed 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 $0.2 million in 2021 pursuant to this agreement. Separately, we billed JC Land $0.3 million during 2021 for fuel, maintenance, pilot travel, etc. paid by us on their behalf.

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. In December 2018, the property subject to the lease was transferred to the Joseph W. Craft III Foundation and the Kathleen S. Craft Foundation, which each hold an undivided one-half interest (the "Craft Foundations"). 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 no earned royalties in 2021 or 2020 and paid $0.3 million in 2019.

Craft Foundations

Tunnel Ridge has a surface land lease with an annual payment of $0.2 million, payable in January of each year with the Craft Foundations, which hold an undivided one-half interest each.

Omnibus Agreement

We are party to an omnibus agreement with MGP and AGP, which govern potential competition among us and the other parties to this agreement. Pursuant to the terms of the omnibus agreement, AGP and its affiliates agreed, for so long as Mr. Craft 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, AGP has the ability to purchase businesses, the majority value of which is not mining, marketing or transporting coal, provided AGP 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 an affiliate of AGP at the closing of our initial public offering. Except as provided above AGP and its affiliates are prohibited from engaging in activities wherein they compete directly with us.

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 Grant Thornton LLP is our independent registered public accounting firm for the 2021 year. The firm of Ernst & Young LLP was our independent registered public accounting firm for the 2020 year. The following table sets forth fees paid to Grant Thornton LLP and Ernst & Young LLP during the years ended December 31, 2021 and 2020:

	2021	2020
	(in thousands)	
Audit Fees (1)	$ 670	$ 1,349
Audit-related fees (2)	—	—
Tax fees (3)	—	339
All other fees	—	—
Total	$ 670	$ 1,688

(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. There were no tax services provided by Grant Thornton LLP for 2021.

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***
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	
4.1	Form of Common Unit Certificate (Included as Exhibit A to the Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., included in this Exhibit Index as Exhibit 3.2).	8-K	000-26823 17990766	3.2	07/28/2017	
4.2	Indenture, dated as of April 24, 2017, by and among Alliance Resource Operating Partners, L.P. and Alliance Resource Finance	8-K	000-26823 17798539	4.1	04/24/2017	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
	Corporation, as issuers, Alliance Resource Partners, L.P., as parent, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee.					
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	Amendment and Restatement of Letter of Credit Facility Agreement dated October 2, 2010.	10-Q	000-26823 11823116	10.1	05/09/2011	
10.2	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	
10.3	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	
10.4	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	
10.5	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	
10.6	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	
10.7	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	
10.8(1)	Amended and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.17	03/15/2004	
10.9(1)	First Amendment to the Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.18	03/15/2004	
10.10(1)	Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 583595	10.12	03/29/2000	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.11[1]	Alliance Coal, LLC Supplemental Executive Retirement Plan	S-8	333-85258 02595143	99.2	04/01/2002	
10.12[1]	Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	S-8	333-85258 02595143	99.3	04/01/2002	
10.13	Guaranty by Alliance Resource Partners, L.P. dated March 16, 2012	10-Q	000-26823 12825281	10.3	05/09/2012	
10.14[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	
10.15[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	
10.16	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	
10.17	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	
10.18	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	
10.19[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	
10.20[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	
10.21[1]	First Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 07660999	10.52	03/01/2007	
10.22[1]	Second Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 08654096	10.53	02/29/2008	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.23[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	
10.24[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	
10.25[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	
10.26	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	
10.27[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	
10.28	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	
10.29	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	
10.30	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	
10.31	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	
10.32	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	

		Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File No. and Film No.**	**Exhibit**	**Filing Date**	**Filed Herewith***
10.33	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	
10.34	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	
10.35	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	
10.36(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	
10.37	First Amendment to the Receivables Financing Agreement, dated as of December 4, 2015	10-Q	000-26823 161634229	10.1	05/10/2016	
10.38	Second Amendment to the Receivables Financing Agreement, dated as of February 24, 2016	10-Q	000-26823 161634229	10.2	05/10/2016	
10.39	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	
10.40	Third Amendment to the Receivables Financing Agreement, dated as of December 2, 2016	10-K	000-26823 17636362	10.45	02/24/2017	
10.41	Fourth Amendment to the Receivables Financing Agreement, dated as of November 27, 2017	10-K	000-26823 18634680	10.47	02/23/2018	
10.42	Fifth Amendment to the Receivables Financing Agreement, dated as of January 17, 2018	10-K	000-26823 18634680	10.48	02/23/2018	
10.43	Sixth Amendment to the Receivables Financing Agreement, dated as of June 19, 2018	10-Q	000-26823 18994075	10.2	08/06/2018	
10.44	Seventh Amendment to the Receivables Financing Agreement, dated as of January 16, 2019	10-K	000-26823 19624803	10.52	02/22/2019	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.45	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	
10.46	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	
10.47	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	
10.48	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	
10.49	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	
10.50	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	
10.51	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	
10.52	Eighth Amendment to the Receivables Financing Agreement, dated as of October 22, 2019.	10-Q	000-26823 191192460	10.2	11/05/2019	
10.53	Employment letter to Kirk Tholen, dated October 21, 2019.	10-K	000-26823 20636450	10.61	02/20/2020	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.54	Fifth Amended and Restated Credit Agreement, dated as of March 9, 2020, 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 20711345	10.1	03/13/2020	
10.55	Fifth Amendment to the Alliance Coal and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan.	8-K	000-26823 201385345	10.1	12/14/2020	
10.56	Ninth Amendment to the Receivables Financing Agreement, dated as of January 15, 2021.	10-K	000-26823 21663570	10.64	02/23/2021	
10.57	Tenth Amendment to the Receivables Financing Agreement, dated as of January 14, 2022.					☑
14.1	Code of Ethics for Principal Executive Officer and Senior Financial Officers	10-K	000-26823 13656028	14.1	03/01/2013	
16.1	Letter of Ernst & Young LLP, dated as of March 1,2021.	8-K	000-26823 21695057	16.1	03/01/2021	
21.1	List of Subsidiaries.					☑
23.1	Consent of Grant Thornton LLP.					☑
23.2	Consent of Ernst & Young LLP.					☑
23.3	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 25, 2022, 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 25, 2022, 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 25, 2022, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					☑

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
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 25, 2022, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					☑
95.1	Federal Mine Safety and Health Act Information					☑
96.1	Henderson/Union Resources SEC S-K 1300 Technical Report Summary dated February 2022.					☑
96.2	River View Mine SEC S-K 1300 Technical Report Summary February 2022.					☑
96.3	Hamilton Mine SEC S-K 1300 Technical Report Summary dated February 2022.					☑
96.4	Gibson South Mine SEC S-K 1300 Technical Report Summary dated February 2022.					☑
96.5	Tunnel Ridge Mine SEC S-K 1300 Technical Report Summary dated February 2022.					☑
99.1	Report of Netherland, Sewell & Associates, Inc., dated January 7, 2022					☑
101	Interactive Data File (Form 10-K for the year ended December 31, 2021 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 25, 2022.

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 25, 2022
/s/ Brian L. Cantrell Brian L. Cantrell	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2022
/s/ Robert J. Fouch Robert J. Fouch	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 25, 2022
/s/ Nick Carter Nick Carter	Director	February 25, 2022
/s/ Robert J. Druten Robert J. Druten	Director	February 25, 2022
/s/ John H. Robinson John H. Robinson	Director	February 25, 2022
/s/ Wilson M. Torrence Wilson M. Torrence	Director	February 25, 2022

ALLIANCE RESOURCE
PARTNERS, L.P.

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