ALLIANCE RESOURCE PARTNERS LP
Form 10-K
February 28, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

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FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013

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

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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	Name of Each Exchange On Which Registered
Common Units representing limited partner interests	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. [X] 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 [X] 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. [X] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [X] 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. [X]

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

Large Accelerated Filer [X] Accelerated Filer [ ] Non-Accelerated Filer [ ] Smaller Reporting Company [ ]

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

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $1,469,278,739 as of June 28, 2013, 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 28, 2014, 37,030,317 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

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FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K may constitute forward-looking statements. These statements are based on our beliefs as well as assumptions made by, and information currently available to, us. When used in this document, the words anticipate, believe, continue, estimate, expect, forecast, may, project, will, and similar expressions identify forward-looking statements. Witho the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- changes in competition in coal markets and our ability to respond to such changes;
- changes in coal prices, which could affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;
- legislation, regulations, and court decisions and interpretations thereof, including those relating to the environment, mining, miner health and safety 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;
- dependence on significant customer contracts, including renewing customer contracts upon expiration of existing contracts;
- changing global economic conditions or in industries in which our customers operate;
- 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;
- adjustments made in price, volume or terms to existing coal supply agreements;
- fluctuations in coal demand, prices and availability;
- our productivity levels and margins earned on our coal sales;
- changes in raw material costs;
- changes in the availability of skilled labor;
- our ability to maintain satisfactory relations with our employees;

- increases in labor costs, adverse changes in work rules, or cash payments or projections associated with post-mine reclamation and workers compensation claims;

- increases in transportation costs and risk of transportation delays or interruptions;

- operational interruptions due to geologic, permitting, labor, weather-related or other factors;

- risks associated with major mine-related accidents, such as mine fires, or interruptions;

- results of litigation, including claims not yet asserted;

- 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 pension, black lung benefits and other post-retirement benefit liabilities;

- 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, such as natural gas, nuclear energy and renewable fuels;

- uncertainties in estimating and replacing our coal reserves;

- a loss or reduction of benefits from certain tax deductions and credits;

- difficulty obtaining commercial property insurance, and risks associated with our participation (excluding any applicable deductible) in the commercial insurance property program;

- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with equity investments in companies we do not control; and

- other factors, including those discussed in Item 1A. Risk Factors and Item 3. Legal Proceedings.

If one or more of these or other risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind the risk factors described in Item 1A. Risk Factors below. The risk factors could also cause our actual results to differ materially from those contained in any forward-looking

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statement. We disclaim any obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

You should consider the information above when reading any forward-looking statements contained in this Annual Report on Form 10-K; other reports filed by us with the 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.

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Significant Relationships Referenced in this Annual Report

- References to we, us, our or ARLP Partnership mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.
- References to ARLP mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.
- References to MGP mean Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., also referred to as our managing general partner.
- References to SGP mean Alliance Resource GP, LLC, the special general partner of Alliance Resource Partners, L.P., also referred to as our special general partner.
- References to Intermediate Partnership mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P., also referred to as our intermediate partnership.
- References to Alliance Coal mean Alliance Coal, LLC, the holding company for the operations of Alliance Resource Operating Partners, L.P., also referred to as our operating subsidiary.
- References to AHGP mean Alliance Holdings GP, L.P., individually as the parent company, and not on a consolidated basis.
- References to AGP mean Alliance GP, LLC, the general partner of Alliance Holdings GP, L.P.

PART I

ITEM 1. BUSINESS

General

We are a diversified producer and marketer of coal primarily to major United States (U.S.) utilities and industrial users. We began mining operations in 1971 and, since then, have grown through acquisitions and internal development to become the third-largest coal producer in the eastern U.S. At December 31, 2013, we had approximately 1.1 billion tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. Approximately 288.6 million tons of those reserves are leased to White Oak Resources LLC (White Oak). For more information on White Oak, please read Item 8. Financial Statements and Supplementary Data Note 11. White Oak Transactions. In 2013, we sold a record 38.8 million tons of coal and produced a record 38.8 million tons of coal, of which 3.4% was low-sulfur coal, 18.2% was medium-sulfur coal and 78.4% was high-sulfur coal. In 2013, we sold 93.7% of our total tons to electric utilities, of which 98.7% was sold to utility plants with installed pollution control devices. These devices, also known as scrubbers, eliminate substantially all emissions of sulfur dioxide. We classify low-sulfur coal as coal with a sulfur content of less than 1%, medium-sulfur coal as coal with a sulfur content of 1% to 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

We operate ten underground mining complexes in Illinois, Indiana, Kentucky, Maryland and West Virginia. We also are constructing a new mine in southern Indiana and operate a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Also, we own a preferred equity interest and are making additional equity investments in White Oak and are purchasing and funding development of coal reserves and have constructed and are operating surface facilities at White Oak s new mining complex in southern Illinois. Our mining activities are conducted in three geographic regions commonly referred to in the coal industry as the Illinois Basin, Central Appalachian and Northern Appalachian regions. We have grown historically, and expect to grow in the future, primarily through expansion of our operations by adding and developing mines and coal reserves in these regions.

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 managing general partner, MGP, a Delaware limited liability company, which holds a 0.99% and 1.0001% managing general partner interest in ARLP and the Intermediate Partnership, respectively. AHGP is a Delaware limited partnership that owns and is the controlling member of MGP. AHGP completed its initial public offering (AHGP IPO) on May 15, 2006 and is listed on the NASDAQ Global Select Market under the ticker symbol AHGP. AHGP owns, directly and indirectly, 100% of the members interest of MGP, a 0.001% managing interest in Alliance Coal, the incentive distribution rights (IDR) in ARLP and 15,544,169 common units of ARLP. Our special general partner is owned by Alliance Resource Holdings, Inc., a Delaware corporation (ARH), which is owned by Joseph W. Craft III, the President and Chief Executive Officer and a Director of our managing general partner, and Kathleen S. Craft.

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The following diagram depicts our organization and ownership as of December 31, 2013:

(1) The units held by SGP and most of the units held by the Management Group (some of whom are current or former members of management) are subject to a transfer restrictions agreement that, subject to a number of exceptions (including certain transfers by Mr. Craft in which the other parties to the agreement are entitled or required to participate), prohibits the transfer of such units unless approved by a majority of the disinterested members of the board of directors of AGP pursuant to certain procedures set forth in the agreement or as otherwise provided in the agreement. Certain provisions of the transfer restrictions agreement may cause the parties to it to comprise a group under Rule 13d-5(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act).

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 public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at *http://www.sec.gov*.

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Mining Operations

We produce a diverse range of steam coals with varying sulfur and heat contents, which enables us to satisfy the broad range of specifications required by our customers. The following chart summarizes our coal production by region for the last five years.

	Year Ended December 31,				
Regions	**2013**	**2012**	**2011**	**2010**	**2009**
			(tons in millions)		
Illinois Basin	30.7	28.4	25.5	23.7	20.7
Central Appalachian	2.0	1.9	2.5	2.3	2.6
Northern Appalachian	6.1	4.5	2.8	2.9	2.5
Total	38.8	34.8	30.8	28.9	25.8

The following map shows the location of our mining complexes and projects:

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Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. As of February 1, 2014, we had 3,058 employees, and we operate seven mining complexes in the Illinois Basin.

Dotiki Complex. Our subsidiary, Webster County Coal, LLC (Webster County Coal), operates Dotiki, which is an underground mining complex located near the city of Providence in Webster County, Kentucky. The complex was opened in 1966, and we purchased the mine in 1971. The Dotiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. In connection with the transition of mining operations from the No. 9 and the No. 11 seams, where it has historically operated, to the No. 13 seam, Dotiki constructed a new preparation plant that became operational in early 2012 and has throughput capacity of 1,800 tons of raw coal per hour. Coal from the Dotiki complex is shipped via the CSX Transportation, Inc. (CSX) and Paducah & Louisville Railway, Inc. (PAL) railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon Transfer Terminal, LLC (Mt. Vernon) transloading facility, for barge deliveries.

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 high-sulfur coal. Warrior completed construction of a new preparation plant in the first quarter of 2009, which has throughput capacity of 1,200 tons of raw coal per hour. Warrior s production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. In 2011, Warrior acquired the Richland No. 9 Mine (Richland) located near the Warrior complex. Coal produced from Richland is processed through Warrior s preparation plant and is expected to be exhausted in 2014.

Pattiki Complex. Our subsidiary, White County Coal, LLC (White County Coal), operates Pattiki, an underground mining complex located near the city of Carmi in White County, Illinois. We began construction of the complex in 1980 and have operated it since its inception. The Pattiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. The preparation plant has throughput capacity of 1,000 tons of raw coal per hour. Coal from the Pattiki complex is shipped via the Evansville Western Railway, Inc. (EVW) railroad directly, or via connection with the CSX railroad, to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries.

Hopkins Complex. The Hopkins complex, which we acquired in January 1998, is located near the city of Madisonville in Hopkins County, Kentucky. Our subsidiary, Hopkins County Coal, LLC (Hopkins County Coal) operates the Elk Creek underground mine using continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Coal produced from the Elk Creek mine is processed and shipped through Hopkins County Coal s preparation plant, which has throughput capacity of 1,200 tons of raw coal per hour. Elk Creek s production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries.

Gibson Complex. Our subsidiary, Gibson County Coal, LLC (Gibson County Coal), operates the Gibson North mine, an underground mine located near the city of Princeton in Gibson County, Indiana. The Gibson North mine began production in November 2000 and utilizes continuous mining units employing room-and-pillar mining techniques to produce medium-sulfur coal. The Gibson North mine s preparation plant, which is leased from an affiliate, has throughput capacity of 700 tons of raw coal per hour. Production from the Gibson North mine is either shipped by truck on U.S. and state highways or transported by rail on the CSX and Norfolk Southern Railway Company (NS) railroads directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries.

Gibson County Coal is constructing the Gibson South mine, also located near the city of Princeton in Gibson County, Indiana. The Gibson South mine will be an underground mine and will utilize continuous mining units employing room-and-pillar mining techniques to produce medium-sulfur coal. The Gibson South mine s preparation plant will have throughput capacity of 1,800 tons of raw coal per hour. Production from Gibson South mine will be shipped by truck on U.S. and state highways or transported by rail from the Gibson North rail loadout facility directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge delivery. Construction of the mine began in 2011, and we expect production to begin in the third quarter of 2014 and to reach 2.5 million to 3.5 million tons in 2015. The mine will have the capacity to expand production to over 5.0 million tons per

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year, dependent on market demand. Capital expenditures required to develop the Gibson South mine are estimated to be in the range of approximately $200.0 million to $210.0 million, of which approximately $129.3 million has been incurred as of December 31, 2013. These amounts exclude capitalized interest and capitalized mine development costs associated with incidental production. (For more information about mine development costs, please read Mine Development Costs under Item 8. Financial Statements and Supplementary Data Note 2. Summary of Significant Accounting Policies.)

River View Complex. Our subsidiary, River View Coal, LLC (River View), operates the River View mine located in Union County, Kentucky. The River View mine began production in 2009, and utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. River View s preparation plant has throughput capacity of 1,800 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.

Sebree Mining Complex. On April 2, 2012, we acquired substantially all of Green River Collieries, LLC s assets related to its coal mining business and operations located in Webster and Hopkins Counties, Kentucky, including the Onton No. 9 mining complex (Onton mine). The Onton mine is operated by our subsidiary, Sebree Mining, LLC (Sebree Mining). Sebree Mining utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. The Onton mine s preparation plant, which is leased from a third-party, has throughput capacity of 750 tons of raw coal per hour. Coal from Sebree Mining s mining complex is transported by overland belt to a barge loading facility on the Green River for shipment to customers, or is shipped via truck on U.S. and state highways directly to customers.

Sebree Mining is in the process of permitting undeveloped reserves in Webster County, Kentucky, which we refer to as the Sebree Reserves, and related property for future development. We control these reserves through our subsidiaries, Alliance Resource Properties, LLC (Alliance Resource Properties) and ARP Sebree, LLC (ARP Sebree).

Central Appalachian Operations

Our Central Appalachian mining operations are located in eastern Kentucky. As of February 1, 2014, we had 267 employees, and we operate one mining complex in Central Appalachia, with a second complex idled.

Pontiki Complex. The Pontiki complex is located near the city of Inez in Martin County, Kentucky. Our subsidiary, Pontiki Coal, LLC (Pontiki), owns the mining complex and controls the reserves. The preparation plant has throughput capacity of 900 tons of raw coal per hour. Coal produced from the mine can be shipped via the NS railroad directly to customers or to various transloading facilities on the Ohio River for barge deliveries, or by truck via U.S. and state highways directly to customers or to various docks on the Big Sandy River for barge deliveries. The Pontiki complex was idled on November 27, 2013, due to limited market opportunities. For information on the Pontiki mining complex, please read Item 8. Financial Statements and Supplementary Data Note 4. Asset Impairment Charge of this Annual Report on Form 10-K.

MC Mining Complex. The MC Mining complex is located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. Our subsidiary, MC Mining, LLC (MC Mining), owns the mining complex and controls the reserves, and our subsidiary, Excel Mining, LLC (Excel) conducts all mining operations. The underground operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. In 2011, Excel began development mining in a new area containing in excess of 10.0 million saleable tons of coal, to which all mining was transitioned in 2013. The preparation plant has throughput capacity of 1,000 tons of raw coal per hour.

Substantially all of the coal produced at MC Mining in 2013 met or exceeded the compliance requirements of Phase II of the Federal Clean Air Act (CAA) (see Regulation and Laws *Air Emissions* below). Coal produced from the mine is shipped via the CSX railroad directly to customers or to various transloading facilities on the Ohio River for barge deliveries, or by truck via U.S. and state highways directly to customers or to various docks on the Big Sandy River for barge deliveries.

Northern Appalachian Operations

Our Northern Appalachian mining operations are located in Maryland and West Virginia. As of February 1, 2014, we had 738 employees, and we operate two mining complexes in Northern Appalachia. We also control undeveloped reserves in West Virginia and Pennsylvania.

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Mettiki Complex. The Mettiki Complex 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)). In addition, production from the Mountain View mine can be supplemented with production from a smaller-scale mine operated by a third-party on property in Maryland controlled by another of our subsidiaries, Backbone Mountain, LLC. Mettiki (WV) began continuous miner development of the Mountain View mine in July 2005 and began longwall mining in November 2006. The Mountain View mine produces medium-sulfur coal which is transported by truck either to the Mettiki (MD) preparation plant for processing 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 export metallurgical coal markets.

Tunnel Ridge Complex. Our subsidiary, Tunnel Ridge, LLC (Tunnel Ridge), operates the Tunnel Ridge mine, an underground, longwall mine in the Pittsburgh No. 8 coal seam, located near Wheeling, West Virginia. Tunnel Ridge began construction of the mine and related facilities in 2008. Development mining began in 2010, and longwall mining operations began at Tunnel Ridge in May 2012. The mine produced 3.7 million tons in 2013 and we expect annual production to ultimately reach approximately 5.8 million tons. Coal produced from the Tunnel Ridge mine is transported by conveyor belt to a barge loading facility on the Ohio River. Through an agreement with a third-party, Tunnel Ridge has the ability to transload coal from barges for rail shipment on Wheeling and Lake Erie Railway.

Penn Ridge. Our subsidiary, Penn Ridge Coal, LLC (Penn Ridge), is party to a coal lease agreement effective December 31, 2005 with Allegheny Pittsburgh Coal Company (Allegheny), pursuant to which Penn Ridge leases Allegheny s Buffalo coal reserve in Washington County, Pennsylvania, which is estimated to include approximately 56.7 million tons of proven and probable high-sulfur coal in the Pittsburgh No. 8 seam. Penn Ridge has initiated the permitting process for the Buffalo coal reserves and continues to evaluate development. (For more information on the permitting process, and matters that could hinder or delay the process, please read Regulation and Laws *Mining Permits and Approvals*.) Development of the project is regulatory and market dependent, and its timing is open-ended pending obtaining all required regulatory approvals, sufficient coal sales commitments to support the project and final approval by the board of directors of our managing general partner (Board of Directors).

Other Operations

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 60,000 to 70,000 tons. During 2013, the terminal loaded approximately 1.9 million tons for customers of Gibson County Coal, Warrior, Webster County Coal, White County Coal, and White Oak.

Coal Brokerage

As markets allow, we buy coal from non-affiliated producers principally throughout the eastern U.S., which we then resell. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal. In 2013, our financial results were not significantly impacted by coal brokerage.

Alliance WOR Processing, LLC

In September 2011, we completed a series of transactions with White Oak related to the development of White Oak Mine No. 1 near the city of McLeansboro, Illinois, which is under construction and will be an underground longwall mining operation producing high-sulfur coal from the Herrin No. 6 seam. Initial production from the continuous miner development units began in 2013, and longwall mining is expected to begin in the second half of 2014. As part of the White Oak transaction, our subsidiary, Alliance WOR Processing, LLC (WOR Processing), contracted with White Oak to construct, own, and operate the coal handling and processing facilities associated with the Mine No. 1 mine, which has the capacity to process 2,000 tons of raw coal per hour. WOR Processing processed 402,000 tons of coal feedstock in 2013. White Oak has the ability to ship production from the Mine No. 1 mine via rail directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. WOR Processing also has an equity investment in White Oak. For more information about the White Oak transactions, please read Item 8. Financial Statements and Supplementary Data Note 11. White Oak Transactions.

Alliance Resource Properties, LLC

Alliance Resource Properties owns coal reserves that it leases to certain of our subsidiaries that operate our mining complexes. In September 2011, Alliance Resource Properties subsidiary, Alliance WOR Properties, LLC (WOR Properties), acquired from and leased back to White Oak the rights to approximately 204.9 million tons of proven and probable high-sulfur coal reserves. In 2013, Alliance Resource Properties acquired from and leased back to White Oak 89.9 million additional tons of proven and probable high-sulfur coal reserves. Approximately 146.9 million tons of those reserves are currently being developed for future mining by White Oak. White Oak pays WOR Properties earned royalties and during the period beginning January 1, 2015 and ending December 31, 2034 will pay WOR Properties a fully recoupable minimum monthly royalty. WOR Properties began receiving royalties from White Oak in 2013 with the start-up of incidental production from White Oak s mine development.

Matrix Group

Our subsidiaries, Matrix Design Group, LLC (Matrix Design) and Alliance Design Group, LLC (Alliance Design) (collectively, Matrix Group), provide a variety of mine products and services for our mining operations and to unrelated parties. We acquired this business in September 2006. Matrix Group s products and services include design and installation of underground mine hoists for transporting employees and materials in and out of mines; design of systems for automating and controlling various aspects of industrial and mining environments; and design and sale of mine safety equipment, including its miner and equipment tracking and proximity detection systems. In 2013, our financial results were not significantly impacted by Matrix Group s activities.

Additional Services

We develop and market additional services in order to establish ourselves as the supplier of choice for our customers. Examples of the kind of services we have offered to date include ash and scrubber sludge removal, coal yard maintenance and arranging alternate transportation services. Historically, and in 2013, revenues from these services were immaterial. In addition, our affiliate, Mid-America Carbonates, LLC (MAC), which is a joint venture with White County Coal, manufactures and sells rock dust to us and to unrelated parties. In 2013, our financial results were not significantly impacted by MAC s business.

Reportable Segments

Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and Segment Information under Item 8. Financial Statements and Supplementary Data Note 21. Segment Information for information concerning our reportable segments.

Coal Marketing and Sales

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 us and our customers in that they provide greater predictability of sales volumes and sales prices. In 2013, approximately 93.5% and 94.2% of our sales tonnage and total coal sales, respectively, were sold under long-term contracts (contracts having a term of one year or greater) with committed term expirations ranging from 2014 to 2020. As of February 14, 2014, our nominal commitment under long-term contracts was approximately 36.7 million tons in 2014, 27.0 million tons in 2015, 21.2 million tons in 2016 and 9.4 million tons in 2017. The commitment of coal under contract is an approximate number because a limited number of our contracts contain provisions that could cause the nominal commitment to increase or decrease; however, the overall variance to total committed sales is minimal. The contractual time commitments for customers to nominate future purchase volumes under these contracts are typically sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal commitment can otherwise change because of reopener provisions contained in certain of these long-term contracts.

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

Reliance on Major Customers

Our two largest customers in 2013 were Louisville Gas and Electric Company and Tennessee Valley Authority. During 2013, we derived approximately 26.5% of our total revenues from these two customers and at least 10.0% of our total revenues from each of the two. For more information about these customers, please read   Item 8. Financial Statements and Supplementary Data   Note 20. Concentration of Credit Risk and Major Customers.

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), transportation costs from the mine to the customer and the reliability of supply. Our principal competitors include Alpha Natural Resources, Inc., Arch Coal, Inc., CONSOL Energy, Inc., Foresight Energy LLC, James River Coal Company, Murray Energy, Inc., Patriot Coal Corp., and Peabody Energy Corp. Some of these coal producers are larger and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in the Illinois Basin, Central Appalachian and Northern Appalachian regions. The prices we are able to obtain for our 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. Additionally, we export a portion of our coal into the international coal markets. The prices we are able to obtain for our export coal are influenced by a number of factors, such as global economic conditions, weather patterns and political instability, among others. Further, coal competes with other fuels such as petroleum, natural gas, nuclear energy and renewable energy sources for electrical power generation. Over time, costs and other factors, such as safety and environmental considerations, may affect the overall demand for coal as a fuel. For additional information, please see   Item 1A. Risk Factors.   As the price of domestic coal increases, we may also begin to compete with companies that produce coal from one or more foreign countries.

Transportation

Our coal is transported to our customers by rail, truck and barge. Depending on the proximity of the customer to the mine and the transportation available for delivering coal to that customer, transportation costs can be a substantial part of the total delivered cost of a customer s coal. As a consequence, the availability and cost of transportation constitute important factors in the marketability of coal. We believe our mines are located in favorable geographic locations that minimize transportation costs for our customers, and in many cases we are able to accommodate multiple transportation options. Typically, our customers pay the transportation costs from the mining complex to the destination, which is the standard practice in the industry. Approximately 48.5% of our 2013 sales volume was initially shipped from the mines by rail, 12.4% was shipped from the mines by truck and 39.1% was shipped from the mines by barge. In 2013, the largest volume transporter of our coal shipments was the CSX railroad which moved approximately 25.2% of our tonnage over its rail system. The practices of, and rates set by, 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 mine.

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Regulation and Laws

The coal mining industry is subject to extensive regulation by federal, state and local authorities on matters such as:

- employee health and safety;
- mine permits and other licensing requirements;
- air quality standards;
- water quality standards;
- storage of petroleum products and substances which are regarded as hazardous under applicable laws or which, if spilled, could reach waterways or wetlands;
- plant and wildlife protection;
- reclamation and restoration of mining properties after mining is completed;
- discharge of materials;
- 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.

In addition, the utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect 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 or our customers ability to use coal. For more information, please see risk factors described in Item 1A. Risk Factors below.

We are committed to conducting mining operations in compliance with applicable federal, state and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, particularly the regulatory system of the Mine Safety and Health Administration (MSHA) where citations can be issued without regard to fault and many of the standards include subjective elements, it is not reasonable to expect any coal mining company to be free of citations. When we receive a citation, we attempt to remediate any identified condition immediately. None of our violations to date has had a material impact on our operations or financial condition. While it is not possible to quantify all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations has substantially increased the cost of coal mining for domestic coal producers.

Capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value of the estimated cost of asset retirement obligations and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations and mine closing costs are based upon permit requirements and the costs and timing of asset retirement obligations and mine closing procedures. Although management believes it has made adequate provisions for all expected reclamation and other costs associated with mine closures, future operating results would be adversely affected if these accruals were insufficient.

Mining Permits and Approvals

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

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

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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

Stringent safety and health standards have been imposed by federal legislation since the Federal Coal Mine Health and Safety Act of 1969 (CMHSA) was adopted. The Federal Mine Safety and Health Act of 1977 (FMSHA), and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards of the CMHSA, and imposed 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. The 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 U.S. for protection of employee safety and have a significant effect on our operating costs. Although many of the requirements primarily impact underground mining, our competitors in all of the areas in which we operate are subject to the same laws and regulations.

The FMSHA has been construed as authorizing MSHA to issue citations and orders pursuant to the legal doctrine of strict liability, or liability without fault, and FMSHA requires imposition of a civil penalty for each cited violation. Negligence and gravity assessments, and other factors can result in the issuance of various types of orders, including orders requiring withdrawal from the mine or the affected area, and some orders can also result in the imposition of civil penalties. The 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. Among these new proposed regulations is MSHA s proposed rule titled Lowering Miner s Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors. The proposed rule would require a 50% reduction in the allowable respirable coal mine dust exposure limits and require the use of sampling data taken from a single sample rather than an average of samples. The proposed rule would also increase oversight by MSHA regarding coal mine dust and ventilation issues at each mine, including the approval process for ventilation plans at each mine. A final rule is currently under review at the White House Office of Management and Budget.

Additionally, in the fall of 2013, MSHA announced that as a part of its regulatory agenda it intends to develop a proposed rule to revise the process for proposing civil penalties. MSHA last revised the process for proposing civil penalties in 2006 and, as discussed above, the revisions resulted in substantially increased civil penalties for regulatory violations cited by MSHA.

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Effective March 25, 2013, MSHA began implementing its revised Pattern of Violation (POV) standards under the FMSHA. Under this new POV standard, MSHA eliminated the ninety (90) day window, during which mine operators meeting certain initial POV screening criteria could take corrective action and engage in mitigation efforts to avoid being placed on POV status. Additionally, MSHA began making POV determinations based upon enforcement actions as issued, rather than enforcement actions that have been rendered final following the opportunity for administrative or judicial review. For mine operators placed on POV status, MSHA will thereafter issue an order withdrawing miners from the area affected by any enforcement action designated by MSHA as posing a significant and substantial, or S&S, hazard to the health and/or safety of miners. Further, the mine operator can be removed from POV status only upon: (1) a complete inspection of the entire mine with no S&S enforcement actions issued by MSHA or (2) no POV-related withdrawal orders being issued by MSHA within ninety (90) days following the mine operator being placed on POV status. The National Mining Association (NMA) and several mine operators already affected by the new POV standards are challenging those standards in federal court, but it is unclear when a final decision on the validity of the new POV standards can be anticipated.

On August 31, 2011, MSHA published proposed rules that, if finalized, will require mine operators to install proximity detection systems on continuous mining machines. The proximity detection systems initiate a warning or shutdown the continuous mining machine depending on the proximity of the machine to a miner.

Subsequent to passage of the MINER Act, Illinois, Kentucky, Pennsylvania and West Virginia have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight; and since January 2012, West Virginia has continued to consider additional mine safety legislation. Additionally, state administrative agencies can promulgate administrative rules and regulations affecting our operations. For example, the West Virginia State Board of Coal Mine Health and Safety recently proposed, and opened for public comment, an administrative rule requiring the installation of proximity detection equipment on certain continuous mining machines, as well as the implementation of additional safety standards for underground coal mine section haulage equipment and equipment operators. 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 are unable to quantify the full impact, implementing and complying with these new state and federal safety laws and regulations have had, and are expected to continue to have, an adverse impact on our results of operations and financial position.

Black Lung Benefits Act

The Black Lung Benefits Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981 (BLBA) requires businesses that conduct current mining operations to make payments of black lung benefits to current and former coal miners with black lung disease and to some survivors of a miner who dies from this disease. The BLBA levies a tax on production of $1.10 per ton for underground-mined coal and $0.55 per ton for surface-mined coal, but not to exceed 4.4% of the applicable sales price, in order to compensate miners who are totally disabled due to black lung disease and some survivors of miners who died from this disease, and who were last employed as miners prior to 1970 or subsequently where no responsible coal mine operator has been identified for claims. In addition, BLBA provides that some claims for which coal operators had previously been responsible are or will become obligations of the government trust funded by the tax. The Revenue Act of 1987 extended the termination date of this tax from January 1, 1996, to the earlier of January 1, 2014, or the date on which the government trust becomes solvent. For miners last employed as miners after 1969 and who are determined to have contracted black lung, we self-insure the potential cost of compensating such miners using our actuary estimates of the cost of present and future claims. We are also liable under state statutes for black lung claims. Congress and state legislatures regularly consider various items of black lung legislation, which, if enacted, could adversely affect our business, results of operations and financial position.

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

The Patient Protection and Affordable Care Act enacted in 2010, includes significant changes to the federal black lung program, retroactive to 2005, including an automatic survivor benefit paid upon the death of a miner with an

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awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes could have a material impact on our costs expended in association with the federal black lung program.

Workers Compensation

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 or workers who suffer employment related deaths. Several states in which we operate consider changes in workers compensation laws from time to time. We generally self-insure this potential expense using our actuary estimates of the cost of present and future claims. 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.*

Coal Industry Retiree Health Benefits Act

The Federal Coal Industry Retiree Health Benefits Act (CIRHBA) was enacted to fund health benefits for some United Mine Workers of America retirees. CIRHBA merged previously established union benefit plans into a single fund into which signatory operators and related persons are obligated to pay annual premiums for beneficiaries. CIRHBA also created a second benefit fund for miners who retired between July 21, 1992 and September 30, 1994, and whose former employers are no longer in business. Because of our union-free status, we are not required to make payments to retired miners under CIRHBA, with the exception of limited payments made on behalf of predecessors of MC Mining. However, in connection with the sale of the coal assets acquired by ARH in 1996, MAPCO Inc., now a wholly owned subsidiary of The Williams Companies, Inc., agreed to retain, and be responsible for, all liabilities under CIRHBA.

Surface Mining Control and Reclamation Act

The Federal Surface Mining Control and Reclamation Act of 1977 (SMCRA) and similar state statutes establish operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. Although we have minimal surface mining activity and no mountaintop removal mining activity, SMCRA nevertheless requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of our mining activities.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. Federal law and some states impose on mine operators the responsibility for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. We believe we are in compliance in all material respects with applicable regulations relating to reclamation.

In addition, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The tax for surface-mined and underground-mined coal is $0.28 per ton and $0.12 per ton, respectively. We have accrued the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. Please read Item 8. Financial Statements and Supplementary Data Note 16. 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 (AMD) 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.

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The U.S. Office of Surface Mining Reclamation (OSM) published in November 2009 an Advance Notice of Proposed Rulemaking, announcing its intent to revise the Stream Buffer Zone (SBZ) rule published in December 2008. The SBZ rule prohibits mining disturbances within 100 feet of streams if there would be a negative effect on water quality. Environmental groups brought lawsuits challenging the rule, and in a March 2010 settlement, the OSM agreed to rewrite the SBZ rule. In January 2013, the environmental groups reopened the litigation against OSM for failure to abide by the terms of the settlement. Oral arguments were heard on January 31, 2014. To date, OSM has not proposed a revised SBZ rule, but one is anticipated in August 2014. We are unable to predict the impact, if any, of these actions by the OSM, although the actions potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities near streams, and additional enforcement actions. The requirements of the revised SBZ rule, if adopted, will likely be more strict than the prior SBZ rule and may adversely affect our business and operations.

Following the spill of coal combustion residues (CCRs) in the Tennessee Valley Authority impoundment in Kingston, Tennessee, in December 2009, the U.S. Environmental Protection Agency (EPA) issued proposed rules on CCRs in 2010. The EPA s proposed rule does not address the placement of CCRs in minefills or non-minefill uses of CCRs at coal mine sites. If the OSM regulates placement and use of CCRs at coal mine sites, those actions by the OSM, potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities, and additional enforcement actions.

In March 2013, the OSM published a proposed rule that would require coal companies to pay for the cost of processing permit applications for coal mining on lands under the OSM s direct regulatory jurisdiction. These actions by the OSM potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities, and additional enforcement actions.

Bonding Requirements

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers compensation, to pay certain black lung claims, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors to secure new surety bonds without posting collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. It is possible that surety bond issuers may refuse to renew bonds or may demand additional collateral upon those renewals. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on our ability to produce coal, which could affect our profitability and cash flow.

As of December 31, 2013, we had approximately $88.7 million in surety bonds outstanding to secure the performance of our reclamation obligations.

Air Emissions

The CAA and similar state and local laws and regulations regulate emissions into the air and affect coal mining operations. The CAA directly impacts our coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, 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. In addition, there is pending litigation to force the EPA to list coal mines as a category of air pollution sources that endanger public health or welfare under Section 111 of the CAA and establish standards to reduce emissions from new or modified coal mine sources of methane and other emissions. Installation of additional emissions control technology and any additional measures required under applicable state and federal 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 coal a less attractive fuel alternative in the planning and building of power plants in the future. A significant reduction in coal s 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, directly or indirectly, include, but are not limited to, the following:

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• 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. These requirements would not be supplanted by a replacement rule for the Clean Air Interstate Rule (CAIR), discussed below. In 2013, we sold 93.7% of our total tons to electric utilities, of which 98.7% 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, 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, 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. Under CSAPR, the first phase of the nitrogen oxide and sulfur dioxide emissions reductions would have commenced in 2012 with further reductions effective in 2014. However, on August 21, 2012, the D.C. Circuit Court of Appeals vacated CSAPR, finding EPA exceeded its statutory authority under the CAA and striking down EPA s decision to require federal implementation plans (FIPs), rather than SIPs, to implement mandated reductions. In its ruling, the court ordered EPA to continue administering CAIR but proceed expeditiously to promulgate a replacement rule for CAIR. The Supreme Court granted EPA s certiorari petition appealing the D.C. Circuit s decision and heard oral arguments on December 10, 2013. The Court s decision is expected in 2014. While this litigation delays implementation of CSAPR, it also leaves CAIR in place while the Court considers the merits of the legal challenges to CSAPR. For states to meet their requirements under the CSAPR, a number of coal-fired electric generating units will likely need to be retired, rather than retrofitted with the necessary emission control technologies. These closures would likely reduce the demand for coal.

• In February 2012, EPA adopted the Mercury and Air Toxic Standards (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, 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. Appeals were filed and oral arguments were heard by the D.C. Circuit Court of Appeals in December 2013. If upheld by the court, MATS will force generators to make capital investments to retrofit power plants and will also likely lead to the premature retirement of a number of older coal-fired generating units. The 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 EPA, states, or Congress may decrease the future demand for coal, but we are currently unable to predict the magnitude of any such effect. We continue to evaluate the possible scenarios associated with CSAPR and MATS and the effects they may have on our business and our results of operations, financial condition or cash flows.

• In January 2013, EPA issued final Maximum Achievable Control Technology (MACT) standards for several classes of boilers and process heaters, including large coal-fired boilers and process heaters (Boiler MACT), which require owners of industrial, commercial, and institutional boilers to comply with standards for air pollutants, including mercury and other metals, fine particulates, and acid gases such as hydrogen chloride. Businesses and environmental groups have filed legal challenges to Boiler MACT in the D.C. Court of Appeals and petitioned EPA to reconsider the rule. EPA has granted petitions for reconsideration for certain issues. If Boiler MACT is upheld, EPA estimates the rule will affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. Some owners will make capital expenditures to retrofit boilers and process heaters, while a number of boilers and process heaters will be prematurely retired. The retirements are likely to reduce the demand for coal. The impact

of the regulations will depend on the outcome of these legal challenges and cannot be determined at this time.

- EPA is required by the CAA to periodically re-evaluate the available health effects information to determine whether the national ambient air quality standards (NAAQS) should be revised. Pursuant to this process, EPA has adopted more stringent NAAQS for fine particulate matter (PM), ozone, nitrogen oxide and sulfur dioxide. As a result, some states will be required to amend their existing SIPs to attain and maintain compliance with the new air quality standards and other states will be required to develop new SIPs for areas that were previously in attainment but do not attain the new standards. In addition, under the revised ozone NAAQS, significant additional emissions control expenditures may be required at coal-fired power plants. Initial non-attainment determinations related to the revised sulfur dioxide standard became effective in October 2013. In addition, in January 2013, EPA updated the NAAQS for fine particulate matter emitted by a wide variety of sources including power plants, industrial facilities, and gasoline and diesel engines, tightening the annual PM 2.5 standard to 12 micrograms per cubic meter. The revised standard became effective in March 2013. In November 2013, EPA proposed a rule to clarify PM 2.5 implementation requirements to the states for current 1997 and 2006 non-attainment areas. Attainment dates for the new standards range between 2013 and 2030, depending on the severity of the non-attainment. In July 2009, the D.C. Circuit Court of Appeals vacated part of a rule implementing the ozone NAAQS and remanded certain other aspects of the rule to the EPA for further consideration. On June 6, 2013, EPA proposed a rule for implementing the 2008 ozone NAAQs. EPA has also previously discussed plans to release a new ozone NAAQS. A new standard 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. We do not know whether or to what extent these developments might indirectly reduce the demand for coal.

- 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 recent cases, EPA has decided to negate the SIPs and impose stringent requirements through FIPs. The regional haze program, including particularly 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.

- 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 EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the NSR program. 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. Depending on the ultimate resolution of these cases, demand for coal could be affected.

Carbon Dioxide Emissions

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide, which is considered a GHG. Combustion of fuel for mining equipment used in coal production also emits GHGs. Future regulation of GHG emissions in the U.S. could occur pursuant to future U.S. treaty commitments, new domestic legislation or regulation by EPA. President Obama has expressed support for a mandatory cap and trade program to restrict or regulate emissions of GHGs and Congress has recently considered various proposals to reduce GHG emissions, and it is possible federal legislation could be adopted in the future. Internationally, the Kyoto Protocol set binding emission targets for developed countries that ratified it (the U.S. did not ratify, and Canada officially withdrew from its Kyoto commitment in 2012) to reduce their global GHG emissions. The Kyoto Protocol was nominally extended past its expiration date of December 2012, with a requirement for a new legal construct to be put into place by 2015. If a replacement treaty or other international arrangement is reached, it likely would require additional reductions in GHG emissions that could, in turn, have a global impact on the demand for coal. Also, 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. 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, EPA has begun to regulate GHG emissions under the CAA based on the U.S. Supreme Court s 2007 decision in *Massachusetts v. EPA* that EPA has authority to regulate GHG emissions. In 2009, EPA issued a final rule, known as the Endangerment Finding, declaring that GHG emissions, including carbon dioxide and methane, endanger public health and welfare and that six GHGs, including carbon dioxide and methane, emitted by motor vehicles endanger both the public health and welfare.

In May 2010, EPA issued its final tailoring rule for GHG emissions, a policy aimed at shielding small emission sources from CAA permitting requirements. EPA s rule phases in various GHG-related permitting requirements beginning in January 2011. Beginning July 1, 2011, EPA requires facilities that must already obtain NSR permits (new or modified stationary sources) for other pollutants to include GHGs in their permits for new construction projects that emit at least 100,000 tons per year of GHGs and existing facilities that increase their emissions by at least 75,000 tons per year. These permits require that the permittee adopt the best available control technology.

As a result of revisions to its preconstruction permitting rules that became fully effective in 2011, EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominantly carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants.

In March 2012, EPA proposed New Source Performance Standards (NSPS) for carbon dioxide emissions from new fossil fuel-fired power plants. The proposal requires new coal units to meet a carbon dioxide emissions standard of 1,000 lb CO_2/MWh, which is equivalent to the carbon dioxide emitted by a natural gas combined cycle unit. In January 2014, EPA formally published its re-proposed NSPS for carbon dioxide emissions from new power plants. The re-proposed rule requires an emissions standard of 1,100 lb CO_2/MWh for new coal-fired power plants. To meet such a standard, new coal plants would be required to install carbon capture and storage (CCS) technology. Legal challenges to the proposed NSPS have been filed; more legal challenges are expected once EPA issues a final rule. Comments are due March 10, 2014, and a final rule is expected shortly thereafter. If the proposed rule is finalized as currently drafted, the rule will reduce the demand for coal in the future.

In June 2013, the President directed EPA to propose carbon dioxide emissions requirements for existing and modified power plants by June 1, 2014 and to finalize the requirements by June 1, 2015. While the potential impacts are unknown until EPA issues a proposal, the requirements could lead to additional premature retirements of coal-fired generating units and reduce the demand for coal. Congress has rejected legislation to restrict carbon dioxide emissions from existing power plants and it is unclear whether EPA has the legal authority to regulate carbon dioxide emissions for existing and modified power plants without additional Congressional authority. Accordingly, legal challenges are expected for the anticipated carbon dioxide emissions requirements.

On June 28, 2010, EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule requiring all stationary sources that emit more than 25,000 tons of GHGs per year to collect and report annually to EPA data regarding such emissions occurring after January 1, 2010. This suite of GHG rules affects many of our customers, as well as additional source categories, including all underground mines subject to quarterly methane sampling by MSHA. Underground mines subject to these rules, including ours, were required to begin monitoring GHG emissions on January 1, 2011 and began reporting to EPA in 2012.

In October 2013, the U.S. Supreme Court granted a number of petitions for certiorari seeking review of EPA s approach to GHG regulation. Oral arguments before the Supreme Court are scheduled for February 2014, with a decision anticipated in July. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the coal we produce.

There have been numerous protests of and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators for concerns related to GHG emissions. For instance, various state

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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 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. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect our current and prospective customers, they may reduce the demand for coal-fired power, and may affect long-term demand for our coal. Finally, a federal appeals court allowed a lawsuit pursuing federal common law claims to proceed against certain utilities on the basis that they may have created a public nuisance due to their emissions of carbon dioxide, while a second federal appeals court dismissed a similar case on procedural grounds. The U.S. Supreme Court recently overturned that decision on June 20, 2011, holding that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions. Despite this favorable ruling, tort-type liabilities remain a concern.

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

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

It is possible that future international, federal and state initiatives to control GHG emissions could result in increased costs associated with coal 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 coal consumption could result in some customers switching to alternative sources of fuel, or otherwise adversely affect our operations and demand for our products, which could have a material adverse effect on our business, financial condition and results of operations.

Water Discharge

The Federal Clean Water Act (CWA) and similar state and local laws and regulations affect coal mining operations by imposing restrictions on effluent discharge into waters and the discharge of dredged or fill material into the waters of the U.S. Regular monitoring, as well as compliance with reporting requirements and performance standards, is a precondition for the issuance and renewal of permits governing the discharge of pollutants into water. Section 404 of the CWA imposes permitting and mitigation requirements associated with the dredging and filling of wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact 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. 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.

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The U.S. Army Corps of Engineers (Corps of Engineers) maintains two permitting programs under CWA Section 404 for the discharge of dredged or fill material: one for individual permits and a more streamlined program for general permits. In June 2010, the Corps of Engineers suspended the use of general permits under Nationwide Permit 21 (NWP 21) in the Appalachian states. On February 21, 2012, the Corps of Engineers reissued the final 2012 NWP 21. The Center for Biological Diversity later filed a notice of intent to sue the Corps of Engineers based on allegations the 2012 NWP 21 program violated the Endangered Species Act. 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 EPA to review Section 404 permits issued by the Corps of Engineers, and in 2009, 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 EPA regarding these permits.

For instance, even though the State of West Virginia has been delegated the authority to issue permits for coal mines in that state, EPA is taking a more active role in its review of National Pollutant Discharge Elimination System (NPDES) permit applications for coal mining operations in Appalachia. EPA has stated that it plans to review all applications for NPDES permits. Indeed, final guidance issued by EPA on July 21, 2011, encouraged EPA Regions 3, 4 and 5 to object to the issuance of state program NPDES permits where the Region does not believe that the proposed permit satisfies the requirements of the CWA, and with regard to state issued general Section 404 permits, support the previously drafted Enhanced Coordination Procedures (ECP). On October 6, 2011, the U.S. District Court for the District of Columbia rejected the ECP on several different legal grounds and later, this same court enjoined EPA from any further usage of its final guidance. Any future application of procedures similar to ECP, such as may be enacted following notice and comment rulemaking, would have the potential to delay issuance of permits for surface coal mines, or to change the conditions or restrictions imposed in those permits.

EPA also has statutory veto power over a Section 404 permit if EPA determines, after notice and an opportunity for a public hearing, that the permit will have an unacceptable adverse effect. On January 14, 2011, EPA exercised its veto power to withdraw or restrict the use of a previously issued permit for Spruce No. 1 Surface Mine in West Virginia, which is one of the largest surface mining operations ever authorized in Appalachia. This action was the first time that such power was exercised with regard to a previously permitted coal mining project. A challenge to EPA s exercise of this authority was made in the federal District Court in the District of Columbia and on March 23, 2012, the court ruled that EPA lacked the statutory authority to invalidate an already issued Section 404 permit retroactively. On April 23, 2013, the D.C. District Court of Appeals reversed this decision and authorized EPA to retroactively veto portions of a Section 404 permit. Any future use of 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.

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

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.

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The Federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows 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.

On June 21, 2010, EPA released a proposed rule to regulate the disposal of certain coal combustion by-products (CCB). The proposed rule set forth two very different options for regulating CCB under RCRA. The first option called for regulation of CCB as a hazardous waste under Subtitle C, which creates a comprehensive program of federally enforceable requirements for waste management and disposal. The second option utilized Subtitle D, which would give EPA authority to set performance standards for waste management facilities and would be enforced primarily through citizen suits. The proposal leaves intact the Bevill exemption for beneficial uses of CCB. In April 2012, several environmental organizations filed suit against EPA to compel EPA to take action on the proposed rule. Several companies and industry groups intervened. A consent decree was entered on January 29, 2014, which set a deadline for a final rule by December 19, 2014 and indicated EPA will use the second option to regulate CCB as a non-hazardous waste under Subtitle D. While classification of CCB as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our customers operating costs and potentially reduce their ability to purchase coal.

Other Environmental, Health And Safety Regulations

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

Employees

To conduct our operations, as of February 1, 2014, we employed 4,313 full-time employees, including 4,000 employees involved in active mining operations, 145 employees in other operations, and 168 corporate employees. Our work force is entirely union-free. We believe that relations with our employees are generally good.

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into an amended and restated administrative services agreement (Administrative Services Agreement) with our managing general partner, the Intermediate Partnership, AGP, AHGP and Alliance Resource Holdings II, Inc. (ARH II). The Administrative Services Agreement superseded the administrative services agreement signed in connection with the AHGP IPO in 2006. Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services for AHGP, AGP and ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these entities as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under this agreement for the year ended December 31, 2013 of $0.4 million from AHGP and $0.1 million from ARH II. Please read Item 13 Certain Relationships and Related Transactions, and Director Independence *Administrative Services*.

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ITEM 1A. RISK FACTORS

Risks Inherent in an Investment in Us

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

The amount of cash we can distribute to holders of our common units or other partnership securities each quarter principally depends on the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of coal we are able to produce from our properties;
- the price at which we are able to sell coal, which is affected by the supply of and demand for domestic and foreign coal;
- the level of our operating costs;
- 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 within our industry;
- 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, if any;

- 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 restraints;
- our ability to borrow under our credit agreement to make distributions to our unitholders; and
- the amount, if any, of cash reserves established by our managing general partner, in its discretion, for the proper conduct of our business.

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

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

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

- our unitholders proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished;
- the ratio of taxable income to distributions may increase; and
- the market price of our common units may decline.

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

As of December 31, 2013, AHGP owned 15,544,169 of our common units. AHGP also owns our managing general partner. In the future, AHGP may sell some or all of these units or it may distribute our common units to the holders of its equity interests and those holders may dispose of some or all of these units. The sale or disposition of a substantial number of our common units in the public markets could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. We do not know whether any such sales would be made in the public market or in private placements, nor do we know what impact such potential or actual sales would have on our unit price in the future.

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

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

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

The credit and risk profile of our managing general partner or its owners may be factors in credit evaluations of us as a master limited partnership. This is because our managing general partner can exercise significant influence or control over our business activities, including our cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of AHGP, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness.

AHGP is principally dependent on the cash distributions from its general and limited partner equity interests in us to service any indebtedness. Any distribution by us to AHGP will be made only after satisfying our then-current obligations to our creditors. Our credit ratings and risk profile could be adversely affected if the ratings and risk profiles of AHGP and the entities that control it were viewed as substantially lower or more risky than ours.

Our unitholders do not elect our managing general partner or vote on our managing general partner s officers or directors. As of December 31, 2013, AHGP owned approximately 42.1% of our outstanding units, a sufficient number to block any attempt to remove our managing general partner.

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 managing general partner and will have no right to elect our managing general partner on an annual or other continuing basis.

In addition, if our unitholders are dissatisfied with the performance of our managing general partner, they will have little ability to remove our general partner. Our managing general partner may not be removed except upon the vote of the holders of at least 66.7% of our outstanding units. As of December 31, 2013, AHGP held approximately 42.1% of our outstanding units. Consequently, it is not currently possible for our managing general partner to be removed without the consent of AHGP. As a result, the price at which our units trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Furthermore, 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 managing general partner and its affiliates, cannot be voted on any matter.

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The control of our managing general partner may be transferred to a third party without unitholder consent.

Our managing general partner may transfer its general partner interest in us to a third party in a merger or in a sale of its equity securities without the consent of our unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the members of our managing general partner to sell or transfer all or part of their ownership interest in our managing general partner to a third party. The new owner or owners of our managing general partner would then be in a position to replace the directors and officers of our managing 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 managing 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 partners and their affiliates, our managing 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 managing general partner may assign this purchase right to any of its affiliates or to us.

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

Prior to making any distributions to our unitholders, we will reimburse our general partners and their 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 managing 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 18. Related-Party Transactions.

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

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

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

As a limited partner in a partnership organized under Delaware law, you could be held liable for our obligations to the same extent as a general partner if you participate in the control of our business. Our general partners generally have 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 partners. Additionally, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully distributed to them. Under Delaware law, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

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

Our partnership agreement contains provisions that waive or consent to conduct by our managing general partner and its affiliates and which reduce the obligations to which our managing 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 partners to the limited partners. Our partnership agreement:

- permits our managing general partner to make a number of decisions in its sole discretion. This entitles our managing 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 managing 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 managing general partner may consider the interests of all parties involved, including its own. Unless our managing general partner has acted in bad faith, the action taken by our managing general partner shall not constitute a breach of its fiduciary duty; and

- provides that our general partners and our officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partners and those other persons acted in good faith.

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

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

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

Our managing 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 managing general partner to deduct from operating surplus 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 partners have conflicts of interest and limited fiduciary responsibilities, which may permit our general partners to favor their own interests to the detriment of our unitholders.

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

- Remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty are limited. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law.

- Our managing 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 partners 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).

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- Our managing 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 managing general partner determines whether to issue additional units or other equity securities in us.

- Our managing general partner determines which costs are reimbursable by us.

- Our managing general partner controls the enforcement of obligations owed to us by it.

- Our managing general partner decides whether to retain separate counsel, accountants or others to perform services for us.

- Our managing 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 managing general partner may borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

Risks Related to our Business

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

Continued or renewed 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 U.S. may not fully recover or may decline if economic conditions deteriorate, which may negatively impact the revenues, margins and profitability of our business;

- any inability of our customers to raise capital could adversely affect their ability to honor their obligations to us; and

- our future ability to access the capital markets may be restricted as a result of future economic conditions, which could materially impact our ability to grow our business, including development of our coal reserves.

A substantial or extended decline in coal prices could negatively impact our results of operations.

Our results of operations are primarily dependent upon the prices we receive for our coal, as well as our ability to improve productivity and control costs. The prices we receive for our production depends upon factors beyond our control, including:

- the supply of and demand for domestic and foreign coal;
- weather conditions and patterns;
- the proximity to and capacity of transportation facilities;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption; and
- prevailing economic conditions.

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

Competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.

We compete with other coal producers in various regions of the U.S. for domestic coal sales. 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 (*i.e.*, volume optionality and multiple supply sources) and reliability of supply. Some competitors may have, among other things, larger financial and operating resources, lower per ton cost of production, or relationships with specific transportation providers. The competition among coal producers may impact our ability to retain or attract

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customers and could adversely impact our revenues and cash available for distribution. In addition, declining prices from an oversupply of coal in the market could reduce our revenues and cash available for distribution.

Any change in consumption patterns by utilities regarding the use of coal could affect our ability to sell the coal we produce.

The domestic electric utility industry accounts for over 92% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as alternative sources of energy. For example, the relatively low price of natural gas has resulted, in some instances, in utilities increasing natural gas consumption while decreasing coal consumption. Future environmental regulation of GHG emissions could accelerate the use by utilities of fuels other than coal. In addition, state and federal mandates for increased use of electricity derived from renewable energy sources could affect demand for coal. A number of states have enacted mandates that require electricity suppliers to rely on renewable energy sources in generating a certain percentage of power. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, could make alternative fuel sources more competitive with coal. A decrease in coal consumption by the domestic electric utility industry could adversely affect the price of coal, which could negatively impact our results of operations and reduce our cash available for distribution.

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

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from coal-fired electric power plants, which are the ultimate consumers of much of our coal. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. These laws and regulations may affect demand and prices for coal. There is also continuing pressure on state and federal regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. Further, far-reaching federal regulations promulgated by EPA in the last four 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 U.S. While CSAPR was struck down by the D.C. Circuit Court of Appeals and many of the other rules, including MATS, are currently being legally challenged by states and private parties, utilities and other generators of electricity made retirement decisions and retired some units based upon EPA s proposed and finalized rules. In June 2013, the President directed EPA to propose CO_2 emissions requirements for existing and modified power plants by June 1, 2014 and to finalize the requirements by June 1, 2015. As a result of these current and proposed laws, regulations and regulatory initiatives, electricity generators may elect to switch to other fuels that generate less of these emissions or by-products, further reducing demand for coal. Please read Item 1. Business Regulation and Laws *Air Emissions,* *Carbon Dioxide Emissions* and *Hazardous Substances and Wastes*.

Increased regulation of GHG emissions could result in increased operating costs and reduced demand for coal as a fuel source, which could reduce demand for our products, decrease our revenues and reduce our profitability.

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide into the atmosphere. On December 15, 2009, EPA published the endangerment finding asserting that emissions of carbon dioxide and other GHGs present an endangerment to public health and the environment, and EPA has begun to regulate GHG emissions pursuant to the CAA. EPA has proposed to regulate GHG emissions from new power plants. The standard proposed is a natural gas standard and would effectively prevent construction of new coal fired power plants. EPA has not proposed to regulate GHG emissions from modified or existing power plants, but could attempt to do so in the future. In addition, it is possible more federal legislation or regulations could be adopted in the future to restrict GHG emissions, as President Obama has expressed support for a mandatory cap and trade program to restrict or regulate emissions of GHGs and Congress has recently considered various proposals to reduce GHG emissions. Many states and regions have adopted GHG initiatives. Also, there have been numerous protests of, and challenges to, the permitting of new coal-fired power plants by environmental organizations and state regulators for concerns related to GHG emissions. Please read Item 1. Business Regulation and Laws *Air Emissions* and *Carbon Dioxide Emissions*.

Future international, federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal 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 coal consumption could result in reduced demand for coal and some customers switching to alternative sources of fuel, which could have a material adverse effect on our business, financial condition and results of operations. In addition, the increased difficulty or inability of our customers to obtain permits for construction of new or expansion of existing coal-fired power plants could adversely affect demand for our coal and have an adverse effect on our business and results of operation.

***Plaintiffs in federal court litigation have attempted to pursue tort claims based on the alleged effects of climate change*.**

In 2004, eight states and New York City sued five electric utility companies in *Connecticut v. American Electric Power Co.* Invoking the federal and state common law of public nuisance, plaintiffs sought an injunction requiring defendants to abate their contribution to the nuisance of climate change by capping carbon dioxide emissions and then reducing them. In June 2011, the U.S. Supreme Court issued a unanimous decision holding that the plaintiffs federal common law claims were displaced by federal legislation and regulations. The U.S. Supreme Court did not address the plaintiffs state law tort claims and remanded the issue of preemption for the district court to consider. While the U.S. Supreme Court held that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, tort-type liabilities remain a possibility and a source of concern. Proliferation of successful climate change litigation could adversely impact demand for coal and ultimately have a material adverse effect on our business, financial condition and results of operations.

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

In 2013, we sold approximately 93.5% of our sales tonnage under contracts having a term greater than one year, which we refer to as long-term contracts. Long-term sales contracts have historically provided a relatively secure market for the amount of production committed under the terms of the contracts. From time to time industry conditions may make it more difficult for us to enter into long-term contracts with our electric utility customers, and if supply exceeds demand in the coal industry, electric utilities may become less willing to lock in price or quantity commitments for an extended period of time. Accordingly, we may not be able to continue to obtain long-term sales contracts with reliable customers as existing contracts expire, which could subject a portion of our revenue stream to the increased volatility of the spot market.

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

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

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

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

During 2013, we derived approximately 26.5% of our total revenues from two customers and at least 10.0% of our 2013 total revenues from each of the two. If we were to lose either of these customers without finding replacement

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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 the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition and results of operations.

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

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

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.

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

Our 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:

- fires;
- mining and processing equipment failures and unexpected maintenance problems;
- unavailability of required equipment;
- prices for fuel, steel, explosives and other supplies;
- fines and penalties incurred as a result of alleged violations of environmental and safety laws and regulations;
- variations in thickness of the layer, or seam, of coal;

- amounts of overburden, partings, rock and other natural materials;
- weather conditions, such as heavy rains, flooding, ice and other storms;
- accidental mine water discharges and other geological conditions;
- 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 had, and can be expected in the future to have, a significant impact on our operating results. Prolonged disruption of production at any of our mines would result in a decrease in our revenues and profitability, which could materially adversely impact our quarterly or annual results.

Effective October 1, 2013, we renewed our annual property and casualty insurance program. The aggregate maximum limit in the commercial property program is $100.0 million per occurrence excluding a $1.5 million deductible for property damage, a 90 or 120-day waiting period for underground business interruption depending on the mining complex and a $10.0 million overall aggregate deductible. We may 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.

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We do not control, and therefore may not be able to cause or prevent certain actions by, White Oak.

White Oak is governed by its board of representatives and, while we are represented on such board, we will not control all of its decisions. Consequently, it may be difficult or impossible for us to cause White Oak to take actions that we believe would be in our or its best interests, and we may be unable to control the amount and timing of cash we will receive from White Oak s operations. Likewise, the White Oak board may control the timing of certain capital investments we are committed to making in White Oak. The lack of control over timing of such revenues and costs could have an adverse impact on the benefits we expect to achieve from the White Oak transactions.

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 coal, which could adversely affect our profitability.

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

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

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

State and federal 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 to have an adverse effect on our results of operation and financial position. For more information, please read Item 1. Business Regulation and Laws *Mine Health and Safety Laws*.

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We may be unable to obtain and renew permits necessary for our 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 Regulations and Laws *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 Central Appalachia, although that action was ultimately overturned by a federal court. As a result of these developments, we may be unable to obtain or experience delays in securing, utilizing or renewing Section 404 permits required for our operations, which could have an adverse effect on our results of operation and financial position. Please read Item 1. Business Regulations and Laws *Water Discharge*.

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

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer s purchasing decision. Increases in transportation costs could make coal a less competitive source of energy or could make our coal production less competitive than coal produced from other sources. Disruption of transportation services due to weather-related problems, flooding, drought, accidents, mechanical difficulties, strikes, lockouts, bottlenecks or other events could temporarily impair our ability to supply coal to our customers. Our transportation providers may face difficulties in the future that may impair our ability to supply coal to our customers, resulting in decreased revenues. If there are disruptions of the transportation services provided by our primary rail or barge carriers that transport our coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. For instance, difficulty in coordinating the many eastern coal loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make coal shipments originating in the eastern U.S. inherently more expensive on a per-mile basis than coal shipments originating in the western U.S. 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 U.S. coal producers have created major competitive challenges for eastern coal producers. In the event of lower transportation costs, the increased competition could have a material adverse effect on our business, financial condition and results of operations.

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

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

Since our formation and the acquisition of our predecessor in August 1999, we have expanded our operations by adding and developing mines and coal reserves in existing, adjacent and neighboring properties. We continually seek to expand our operations and coal reserves. Our future growth could be limited if we are unable to continue to make acquisitions, or if we are unable to successfully integrate the companies, businesses or properties we acquire. We may not be successful in consummating any acquisitions and the consequences of undertaking these acquisitions are

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unknown. Moreover, any acquisition could be dilutive to earnings and distributions to unitholders and any additional debt incurred to finance an acquisition could affect our ability to make distributions to unitholders. Our ability to make acquisitions in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

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

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

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

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

Completion of growth projects and future expansion could require significant amounts of financing which may not be available to us on acceptable terms, or at all.

We plan to fund capital expenditures for our current growth projects with existing cash balances, future cash flows from operations, borrowings under revolving credit facilities and cash provided from the issuance of debt or equity. Our funding plans may, however, be negatively impacted by numerous factors, including higher than anticipated capital expenditures or lower than expected cash flow from operations. In addition, we may be unable to refinance our current revolving credit facility when it expires or obtain adequate funding prior to expiry because our lending counterparties may be unwilling or unable to meet their funding obligations. Furthermore, additional growth projects and expansion opportunities may develop in the future which 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 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 and future expansions 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.

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

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because we deplete our reserves as we mine coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. Replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those of the depleting mines. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal

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companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

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

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

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

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

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

The geological characteristics of some of our coal reserves, such as depth of overburden and coal seam thickness, make them difficult and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those characteristic of the depleting mines. In addition, permitting, licensing and other environmental and regulatory requirements associated with certain of our mining operations are more costly and time-consuming to satisfy. These factors could materially adversely affect the mining operations and cost structures of, and our customers ability to use coal produced by, our mines.

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

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

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

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

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

We have long-term indebtedness, consisting of our outstanding senior unsecured notes, revolving credit facility and term loan agreement. At December 31, 2013, our total long-term indebtedness outstanding was $868.0 million. Our leverage may:

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

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

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

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

Various limitations in our debt agreements may reduce our ability to incur additional indebtedness, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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 state and federal law would have a material adverse effect on us.

Federal and state laws require us to place and maintain bonds to secure our obligations to repair and return property to its approximate original state after it has been mined (often referred to as reclaim or reclamation), to pay federal and state workers compensation and pneumoconiosis, or black lung, benefits and to satisfy other miscellaneous obligations. These bonds provide assurance that we will perform our statutorily required obligations and are referred to as surety bonds. These bonds are typically renewable on a yearly basis. The failure to maintain or the inability to acquire sufficient surety bonds, as required by state and federal 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;
- the ability of current and future surety bond issuers to increase required collateral, or limitations on availability of collateral for surety bond issuers due to the terms of our credit agreements; and
- the exercise by third-party surety bond holders of their rights to refuse to renew the surety.

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

We and our subsidiaries are subject to various legal proceedings, which may have a material 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 8. Financial Statements and Supplementary Data Note 19. Commitments and Contingencies for further discussion.

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Tax Risks to Our Common Unitholders

Our tax treatment depends on our status as a partnership for federal tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) treats us as a corporation for federal income tax purposes, or we become subject to entity-level taxation for state tax purposes, our cash available for distribution to you would be substantially reduced.

The anticipated after-tax benefit of an investment in our units depends largely on our being treated as a partnership for 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, 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 income at the corporate tax rate, which is currently a maximum of 35%, and would likely be liable for state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because taxes would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of the units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state or local income tax purposes, the minimum quarterly distribution (MQD) amount and the target distribution amounts may be adjusted to reflect the impact of that law on us. 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 common 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. For example, from time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. One such legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the qualifying income requirement to be treated as a partnership for U.S. federal income tax purposes.

If the IRS were to contest the 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 federal income tax purposes. The IRS may adopt positions that differ from the positions that we take, even positions taken with the advice of counsel. 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 prices at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

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

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

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

If you sell your units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis therein, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation and depletion recapture. 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.

Tax-exempt entities and non-U.S. persons owning our units face unique tax issues that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, such as individual retirement accounts (IRAs) and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of units and because of other reasons, we adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of units and could have a negative impact on the value of our units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our 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, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our intangible assets and a lesser portion allocated to our tangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

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

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

The Obama administration has 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. No legislation with that effect has been proposed and elimination of those provisions would not impact our financial statements or results of operations. However, elimination of the provisions could result in unfavorable tax consequences for our unitholders and, as a result, could negatively impact our unit price.

The sale or exchange of 50% or more of our capital and profits interests within a twelve-month period will result in the termination of us as a partnership for federal income tax purposes.

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in our filing two tax returns for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in taxable income for the unitholder s taxable year that includes our termination. Our termination would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for U.S. federal income tax purposes following the termination. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has implemented relief procedures whereby if a publicly traded partnership that has technically terminated, requests and the IRS grants special relief, among other things, the partnership may be permitted

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to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

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

In addition to 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. 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 may own property or conduct business in other states in the future. It is your responsibility to file all U.S. federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Coal Reserves

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

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

At December 31, 2013, we had approximately 1.1 billion tons of coal reserves. Approximately 288.6 million tons of those reserves, located in Hamilton County, Illinois, are leased to White Oak and are not reflected in the operations table below. All of the estimates of reserves which are presented in this Annual Report on Form 10-K are of proven and probable reserves (as defined below) and adhere to the standards described in U.S. Geological Survey (USGS) Circular 831 and USGS Bulletin 1450-B. For information on the locations of our mines, please read Mining Operations under Item 1. Business.

The following table sets forth reserve information at December 31, 2013, about our mining operations:

Operations	Mine Type	Heat Content (BTUs per pound)	Proven and Probable Reserves							
			Pounds S02 per MMBTU				Reserve Assignment		Reserve Control	
			<1.2	1.2-2.5	>2.5	Total	Assigned	Unassigned	Owned	Leased
			(tons in millions)							
Illinois Basin Operations										
Dotiki (KY)	Underground	12,000	-	-	44.9	44.9	44.9	-	18.9	26.0
Warrior (KY)	Underground	12,400	-	-	120.1	120.1	81.7	38.4	28.6	91.5
Hopkins (KY)	Underground	12,100	-	-	26.4	26.4	11.2	15.2	6.1	20.3
	/ Surface	11,500	-	-	7.8	7.8	7.8	-	7.8	-
River View (KY)	Underground	11,500	-	-	154.0	154.0	154.0	-	15.0	139.0
Onton (KY)	Underground	11,750	-	-	38.2	38.2	38.2	-	-	38.2
Sebree (KY)	Underground	11,400	-	-	29.7	29.7	-	29.7	3.8	25.9
Pattiki (IL)	Underground	11,500	-	-	51.9	51.9	51.9	-	0.1	51.8
Gibson (North) (IN)	Underground	11,500	0.1	15.1	7.3	22.5	22.5	-	0.1	22.4
Gibson (South) (IN)	Underground	11,500	1.1	26.8	47.4	75.3	75.3	-	21.0	54.3
Region Total			1.2	41.9	527.7	570.8	487.5	83.3	101.4	469.4
Central Appalachian Operations										
Pontiki (KY)	Underground	12,900	-	2.3	0.1	2.4	2.4	-		