ALLIANCE RESOURCE PARTNERS LP
Form 10-K
February 27, 2015
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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, 2014

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 $1,954,760,489 as of June 30, 2014, 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 27, 2015, 74,188,784 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, 2014, we had approximately 1.5 billion tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. Approximately 300.7 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 12. Equity Investments. In 2014, we sold a record 39.7 million tons of coal and produced a record 40.7 million tons of coal, of which 4.0% was low-sulfur coal, 16.0% was medium-sulfur coal and 80.0% was high-sulfur coal. In 2014, we sold 95.6% of our total tons to electric utilities, of which 97.8% 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 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 have funded 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 two geographic regions commonly referred to in the coal industry as the Illinois Basin and 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 31,088,338 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, 2014:

(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.

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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*.

Mining Operations

We produce a diverse range of steam coal 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	**2014**	**2013**	**2012**	**2011**	**2010**
			(tons in millions)		
Illinois Basin	30.9	30.7	28.4	25.5	23.7
Appalachia	9.8	7.4	5.8	4.3	4.3
Other (a)	-	0.7	0.6	1.0	0.9
Total	40.7	38.8	34.8	30.8	28.9

(a) Other includes production from our former Pontiki Coal, LLC (Pontiki) mine, which is located in Martin County, Kentucky. The Pontiki mine ceased operations in November 2013. As a result of the cessation we evaluated the ongoing management of our mining operations and coal sales efforts to ensure that resources were appropriately allocated to maximize our overall results. Based on this evaluation, we have realigned the management of our operating and marketing teams and changed our reportable segment presentation to reflect this realignment. Please see Item 8. Financial Statements and Supplementary Data Note 22. Segment Information for a discussion on our change in segments.

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

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. As of February 1, 2015, we had 3,177 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 is 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 nearby Richland No. 9 Mine

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(Richland). Coal produced from Richland was processed through Warrior s preparation plant until production from the mine was exhausted in 2014. Warrior is currently in the process of transitioning from the No. 11 seam to the No. 9 seam, which is expected to continue over the next two to three years.

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 is 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. The Elk Creek mine is currently expected to cease production in early 2016. Hopkins County Coal also owns the Fies property for potential future development.

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 recently completed construction of the Gibson South mine, also located near the city of Princeton in Gibson County, Indiana. The Gibson South mine is an underground mine and utilizes continuous mining units employing room-and-pillar mining techniques to produce medium-sulfur coal. The Gibson South mine s preparation plant has throughput capacity of 1,800 tons of raw coal per hour. Production from the Gibson South mine is shipped by truck on 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. Production from the mine began in April 2014. The mine will have the capacity to expand production to over 5.0 million tons per year, dependent on market demand. Capital expenditures required to develop the Gibson South mine were approximately $185.5 million. This amount does not include 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, which is located in Union County, Kentucky and is currently the largest room-and-pillar underground coal mine in the U.S. The River View mine began production in 2009, and utilizes continuous mining units 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 (Green River) 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.

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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.

Appalachian Operations

Our Appalachian mining operations are located in eastern Kentucky, Maryland and West Virginia. As of February 1, 2015, we had 1,031 employees, and we operate three mining complexes in Appalachia. We also control undeveloped reserves in West Virginia and Pennsylvania.

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 and 2014 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.

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 temporarily sealed smaller-scale mine 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 international thermal and metallurgical coal markets.

Tunnel Ridge Complex. Our subsidiary, Tunnel Ridge, LLC (Tunnel Ridge), operates the Tunnel Ridge mine, an underground longwall mine in the Pittsburgh No. 8 coal seam, located near Wheeling, West Virginia. Tunnel Ridge began construction of the mine and related facilities in 2008. Development mining began in 2010, and longwall mining operations began at Tunnel Ridge in May 2012. 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 the 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).

White Oak

Alliance WOR Processing, LLC. In September 2011, we completed a series of transactions with White Oak related to the development of the White Oak Mine No. 1 (Mine No. 1) near the city of McLeansboro, Illinois, which is an underground longwall mining operation producing high-sulfur coal from the Herrin No. 6 seam. Initial development production from the continuous miner units began in 2013, and longwall mining began in October 2014. As part of the

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White Oak transaction, our subsidiary, Alliance WOR Processing, LLC (WOR Processing), constructed, owns, and operates the coal handling and processing facilities associated with the Mine No. 1 mine, which have the capacity to process 2,000 tons of raw coal per hour. WOR Processing processed 3.8 million tons of coal feedstock in 2014. 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 a preferred equity investment in White Oak. For more information about the White Oak transactions, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments.

Alliance WOR Properties, LLC. 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. From the initial transaction date in September 2011 through December 31, 2014, WOR Properties has acquired from and leased back to White Oak approximately 104.7 million additional tons of proven and probable high-sulfur coal reserves. Approximately 158.6 million tons of those reserves have been developed for mining by White Oak. White Oak pays WOR Properties earned royalties and during the period beginning January 1, 2015 and ending December 31, 2034 has and will continue to pay WOR Properties a fully recoupable minimum monthly royalty. Earned royalties from coal production in 2014 and 2013 in the amount of $0.2 million and $15.0 thousand were paid to WOR Properties by White Oak.

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 2014, the terminal loaded approximately 1.8 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 2014, we did not have coal brokerage activity.

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. Our financial results were not significantly impacted by Matrix Group s activities.

Alliance Minerals

On November 10, 2014 (the Cavalier Formation Date), our subsidiary, Alliance Minerals, LLC (Alliance Minerals) purchased a 96% ownership interest in Cavalier Minerals JV, LLC (Cavalier Minerals). Cavalier Minerals subsequently contributed $7.4 million in return for a limited partner interest in AllDale Minerals L.P. (AllDale Minerals), an entity created to purchase oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. Between the Cavalier Formation Date and December 31, 2014, Cavalier Minerals contributed an additional $4.2 million and at December 31, 2014 owned a 71.7% interest in AllDale Minerals. In 2014, our financial results were not significantly impacted by Cavalier Minerals investment in AllDale Minerals. For more information about Cavalier Minerals, please read Item 8. Financial Statements and Supplementary Data Note 11. Noncontrolling Interest. For more information about AllDale Minerals, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments.

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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 2014, revenues from these services were immaterial. In addition, our affiliate, Mid-America Carbonates, LLC (MAC), which was a joint venture with White County Coal, manufactures and sells rock dust to us and to unrelated parties. Effective January 1, 2015, White County Coal acquired the remainder of the interest in MAC, which is now a wholly owned subsidiary of Alliance Coal. 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 22. 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 2014, approximately 84.0% and 85.7% 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 2015 to 2021. As of February 13, 2015, our nominal commitment under long-term contracts was approximately 39.3 million tons in 2015, 28.9 million tons in 2016, 12.8 million tons in 2017 and 9.6 million tons in 2018. 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. In 2014, the customer under one of our long-term coal supply agreements notified us that it would not accept any more coal shipments after April 15, 2015. The nominal commitments stated above do not include any shipments under that contract after April 15, 2015. Please read Item 3. Legal Proceedings.

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

Reliance on Major Customers

Our two largest customers in 2014 were Louisville Gas and Electric Company and Tennessee Valley Authority. During 2014, we derived approximately 25.1% of our total revenues from these two customers and at least 10.0% of our

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total revenues from each of the two. For more information about these customers, please read Item 8. Financial Statements and Supplementary Data Note 21. 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 LP, Murray Energy, Inc., Patriot Coal Corporation (Patriot), and Peabody Energy Corporation. 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 and 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 have historically exported 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, barge and truck. 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. Our customers typically pay the transportation costs from the mining complex to the destination, which is the standard practice in the industry. Approximately 45.0% of our 2014 sales volume was initially shipped from the mines by rail, 42.8% was shipped from the mines by barge and 12.2% was shipped from the mines by truck. In 2014, the largest volume transporter of our coal shipments was the CSX railroad, which moved approximately 18.2% of our tonnage over its rail system. The practices of, rates set by and capacity availability of, the transportation company serving a particular mine or customer may affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mine.

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 that are regarded as hazardous under applicable laws or that, 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

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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. 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 or that a current permit will not be revoked.

We are required to post bonds to secure performance under our permits. Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws and regulations described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws and regulations. Regulations also provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations that have outstanding environmental violations. Although, like other coal companies, we have been cited for violations in the ordinary course of our business, we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

Mine Health and Safety Laws

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. 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.

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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.

In 2014, MSHA began implementation of a finalized new regulation titled Lowering Miner s Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors. The final rule implements a reduction in the allowable respirable coal mine dust exposure limits, requires the use of sampling data taken from a single sample rather than an average of samples, and increases oversight by MSHA regarding coal mine dust and ventilation issues at each mine, including the approval process for ventilation plans at each mine, all of which is expected to increase mining costs. Additionally, in July 2014, MSHA proposed a rule addressing the criteria and procedures for assessment of civil penalties. Presently, this new proposed rule is in the notice-and-comment stage of rulemaking. Public commenters have expressed concern that the proposed rule exceeds MSHA s rulemaking authority and would result in substantially increased civil penalties for regulatory violations cited by MSHA. MSHA last revised the process for proposing civil penalties in 2006 and, as discussed above, civil penalties increased significantly.

In January 2015, MSHA published a final rule requiring mine operators to install proximity detection systems on continuous mining machines, over a staggered time frame ranging from November 2015 through March 2018. The proximity detection systems initiate a warning or shutdown the continuous mining machine depending on the proximity of the machine to a miner.

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.

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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, the BLBA provides that some claims for which coal operators had previously been responsible are or will become obligations of the government trust funded by the tax. The Revenue Act of 1987 extended the termination date of this tax from January 1, 1996, to the earlier of January 1, 2014, or the date on which the government trust becomes solvent. 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.

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

The Patient Protection and Affordable Care Act enacted in 2010, includes significant changes to the federal black lung program, retroactive to 2005, including an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes 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.

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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 17. Asset Retirement Obligations. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation or orphaned mine sites and acid mine drainage control on a statewide basis.

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

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. OSM published a notice on December 22, 2014 to vacate the 2008 SBZ rule to comply with an order issued by the U.S. District Court for the District of Columbia. OSM reimplemented the 1983 SBZ rule.

OSM has proposed a Stream Protection Rule (SPR) to replace the vacated SBZ rule. This rule is anticipated to be published as a draft in June 2015. 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 SPR 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. This final rule was published on December 19, 2014. The EPA s final rule does not address the placement of CCRs in minefills or non-minefill uses of CCRs at coal mine sites. OSM has announced their intention to release a proposed rule to regulate placement and use of CCRs at coal mine sites in August 2015. These actions by OSM, potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities, and additional enforcement actions.

In March 2013, 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

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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. For additional information, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources *Off-Balance Sheet Arrangements*.

Air Emissions

The CAA and similar state and local laws and regulations regulate emissions into the air and affect coal mining 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. 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:

- The EPA s Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility s sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA s Acid Rain Program by switching to lower-sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or scrubbers, or by reducing electricity generating levels. In 2014, we sold 95.6% of our total tons to electric utilities, of which 97.8% was sold to utility plants with installed pollution control devices. These requirements would not be supplanted by a replacement rule for the Clean Air Interstate Rule (CAIR), discussed below.

- The CAIR calls for power plants in 28 states and Washington, D.C. to reduce emission levels of sulfur dioxide and nitrogen oxide pursuant to a cap-and-trade program similar to the system in effect for acid rain. In June 2011, 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, in August 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 D.C. Circuit Court of Appeals ordered EPA to continue administering CAIR but proceed expeditiously to promulgate a replacement rule for CAIR. The U.S. Supreme Court granted EPA s certiorari petition appealing the D.C. Circuit Court of Appeals decision and heard oral arguments on December 10, 2013. In April 2014, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals decision, concluding that EPA s approach is lawful. CSAPR has been reinstated and EPA began implementation of Phase 1 requirements on January 1, 2015; Phase 2 will begin in 2017. Some issues that remain will be litigated further in D.C. Circuit Court of Appeals. The impacts of CSAPR are unknown at the present time due to the implementation of Mercury and Air Toxic Standards (MATS), discussed below, and the significant number of coal retirements that have resulted and that potentially will result from MATS.

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- In February 2012, EPA adopted the MATS, which regulates the emission of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal and oil-fired power plants. In March 2013, 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. On April 15, 2014 the D.C. Circuit Court of Appeals upheld MATS. However, on November 25, 2014 the U.S. Supreme Court announced it will review the decision and determine whether EPA unreasonably refused to consider costs when it determined that it was appropriate to regulate hazardous air pollutant emissions from power plants. MATS compliance will continue while the U.S. Supreme Court is considering the rule. Many electric generators have already announced retirements due to the MATS rule. If upheld by the D.C. Circuit Court of Appeals, MATS will force generators to make capital investments to retrofit power plants and could lead to additional premature retirements of older coal-fired generating units. The announced and possible additional retirements are likely to reduce the demand for coal. Apart from MATS, several states have enacted or proposed regulations requiring reductions in mercury emissions from coal-fired power plants, and federal legislation to reduce mercury emissions from power plants has been proposed. Regulation of mercury emissions by 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. Circuit Court of Appeals and petitioned EPA to reconsider the rule. On December 1, 2014, EPA announced reconsideration of the standard and will accept public comment on five issues for its standards on area sources, will review three issues related to its major-source boiler standards, and four issues relating to commercial and solid waste incinerator units. Before reconsideration, EPA estimated the rule will affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. While some owners would make capital expenditures to retrofit boilers and process heaters, a number of boilers and process heaters could be prematurely retired. Retirements are likely to reduce the demand for coal. The impact of the regulations will depend on EPA s reconsideration and the outcome of subsequent legal challenges, and therefore 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. In June 2013, EPA proposed a rule for implementing the 2008 ozone NAAQS. In November 2014, EPA proposed to increase the stringency of the 2008 ozone standard from 75 parts per billion (ppb) to between 65 ppb and 70 ppb. 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.

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- 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 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 (BACT). In June 2012, the D.C. Circuit Court of Appeals upheld these permitting regulations. In June 2014, the U.S. Supreme Court invalidated EPA s position that power plants and other sources can be subject to permitting requirements based on their GHG emissions alone. For CO_2 BACT to apply, CAA permitting must be triggered by another regulated pollutant (e.g., SO_2). Currently the impacts are uncertain. Industry and EPA have filed motions with the D.C Circuit Court of Appeals.

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.

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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 lbs. 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 lbs. 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. EPA has announced its intention to finalize the NSPS in the summer of 2015, along with the existing plant proposal, discussed below. If the proposed rule is finalized as currently drafted, the rule will reduce the demand for coal in the future.

In June 2014, EPA proposed CO_2 emission guidelines for modified and existing fossil fuel-fired power plants under Section 111(d) of the CAA. EPA plans to finalize the Clean Power Plan (CPP) by the summer of 2015 and require states to submit implementation plans by the summer of 2016 (with limited time extensions available). The proposal for existing sources sets CO_2 emission rate requirements for each of 49 states beginning in 2020; the requirements rely on decreased use of coal and increased use of natural gas, renewables, and nuclear for electricity generation, as well as reductions in the amount of electricity used by consumers. In January 2015, EPA also announced that it would propose a federal plan this summer to implement the CPP in states that do not submit plans; the federal plan will be finalized in the summer of 2016. These 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. Challenges to the proposal by a number of states and industry groups are pending before the D.C. Circuit Court of Appeals. It is also likely that additional legal challenges will occur after the publication of the final rule.

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. The Supreme Court heard oral arguments in February 2014. On June 23, 2014, the Supreme Court issued an opinion affirming the D.C. Circuit decision in part and reversing the decision in part. The Court struck down the EPA s tailoring rule, making permanent a temporary exclusion that EPA had provided for small sources. However, the Court s holding affirmed EPA s authority to regulate GHG emissions from the vast majority of sources subject to the Clean Air Act s permitting provisions, and did not affect EPA s ability to regulate GHG emissions from new and existing sources. 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 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 overturned that decision in June 2011, holding that federal common law provides no basis for public

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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. For more information about asset retirement obligations, please read Item 8. Financial Statements and Supplementary Data Note 17. Asset Retirement Obligations. Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of such permitting requirements.

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. In February 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 (ESA). The Corps of Engineers and National Marine Fisheries Service (NMFS) have completed their programmatic ESA Section 7 consultation process on the Corps of Engineers 2012 NWP 21 package, and NMFS has issued a revised biological opinion finding that the NWP 21 program does not jeopardize the continued existence of threatened and endangered species and will not result in the destruction or adverse modification of designated critical habitat. However, the opinion contains 12 additional protective measures the Corps of Engineers will implement in certain districts to enhance the protection of listed species and critical habitat. While these measures will not affect previously verified permit activities where construction has not yet been completed, several Corps of Engineers districts with mining operations will be impacted by the additional protective measures going forward. These measures include additional reporting and notification requirements, potential imposition of new regional conditions and additional actions concerning cumulative effects analyses and mitigation. 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 in July 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). In October 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. The U.S. Supreme Court denied a request to review this decision. 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. In January 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 U.S. District Court for the District of Columbia and in March 2012, that court ruled that EPA lacked the statutory authority to invalidate an already issued Section 404 permit retroactively. In April 2013, the D.C. Circuit Court of Appeals reversed this decision and authorized EPA to retroactively veto portions of a Section 404 permit. The U.S. Supreme Court denied a request to review this decision. 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. In addition, EPA initiated a preemptive veto prior to the filing of any actual permit application for a copper and gold mine based on fictitious mine scenario. The implications of this decision could allow EPA to bypass the state permitting process and engage in watershed and land use planning.

Total Maximum Daily Load (TMDL) regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired 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.

In April 2014, EPA proposed a new definition of the Waters of the United States (WOTUS). This rule is broadly written and expands EPA and Corps of Engineers jurisdiction. WOTUS creates new federal authority over lands, ditches, and potentially on-site mining waters. Of critical concern to our industry is the possibility that many water features commonly found on mine sites which are currently not considered jurisdictional could nevertheless fall within the definition of WOTUS under the proposed rule. Ditches, closed loop systems, on-site ponds, impoundments, and other water management features are integral to mining operations, and are used to manage on-site waters in an environmentally sound and frequently statutorily mandated manner. The rule could lead to substantially increased permitting requirements with more costs, delays, and increased risk of litigation. It is likely that legal challenges will occur after publication of the final rule, which is expected in the first half of 2015.

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

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original conduct on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for the release of hazardous substances may be subject to joint and several liability under CERCLA for the costs of cleaning up releases of hazardous substances and natural resource damages. Some products used in coal mining operations generate waste containing hazardous substances. We are currently unaware of any material liability associated with the release or disposal of hazardous substances from our past or present mine sites.

The Federal Resource Conservation and Recovery Act (RCRA) and 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.

In June 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. EPA finalized the CCB rule on December 19, 2014, setting nationwide solid nonhazardous waste standards for CCB disposal. 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 Federal Safe Drinking Water Act, the Toxic Substance Control Act, and the Emergency Planning and Community Right-to-Know Act. The costs of compliance with these regulations should not have a material adverse effect on our business, financial condition or results of operations.

Employees

To conduct our operations, as of February 1, 2015, we employed 4,439 full-time employees, including 4,128 employees involved in active mining operations, 134 employees in other operations, and 177 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, 2014 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 constraints;
- our ability to borrow under our credit agreement to make distributions to our unitholders; and
- the amount, if any, of cash reserves established by our 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.

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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, 2014, AHGP owned 31,088,338 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, 2014, AHGP owned approximately 42.0% 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, 2014, AHGP held approximately 42.0% 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 19. 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.

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 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 (*e.g.*, volume optionality and multiple supply sources) and reliability of supply. Some competitors may have, among other things, larger financial and operating resources, lower per ton cost of production, or relationships with specific transportation providers. The competition among coal producers may impact our ability to retain or attract

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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 92.4% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as alternative sources of energy. Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed in the U.S. to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain.

In addition, 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 five 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. 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 would require carbon capture and storage (CCS), a technology that is not yet commercially available without government subsidies and that has not been demonstrated in the marketplace. If adopted in the final rule, this requirement would effectively prevent construction of new coal fired power plants. In June 2014, EPA proposed GHG emissions regulations for modified and existing power plants. The rule for modified sources proposes reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants thereby reducing the demand for coal. The rule for existing sources proposes to establish different target emission rates (lbs per megawatt hour) for each state and has an overall goal to achieve a 30% reduction of carbon dioxide emissions from 2005 levels by 2030 and an interim goal of a 25% reduction between 2020 and 2029. If adopted as the final rule and upheld by courts, the regulation could lead to premature retirements of coal-fired electric generating units and significantly reduce the demand for coal. In addition, 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

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by environmental organizations and state regulators due to concerns related to GHG emissions. Please read Item 1. Business Regulation and Laws *Air Emissions* and *Carbon Dioxide Emissions*.

Government regulations have resulted and could continue to result in significant retirements of coal-fired electric generating units. Retirements of coal-fired electric generating units decrease the overall capacity to burn coal and negatively impact coal demand.

Since 2010, utilities have formally announced the retirement or conversion of 462 coal-fired electric generating units by 2025. These retirements and conversions amount to over 72,000 megawatts (MW) or approximately 23% of the 2010 total coal electric generating capacity. By the end of 2015 it is expected that retirement and conversions affecting 49,000 MW, or approximately 16% of the 2010 total electric generating capacity, will have already occurred. Most of these announced and completed retirements and conversions have been attributed to EPA regulations, although other factors such as an aging coal fleet and low natural gas prices have also played a role. The reduction in coal electric capacity negatively impacts overall coal demand. Additional regulations, such as EPA s proposed regulation to reduce GHG emissions from existing power plants, and other factors could lead to additional retirements and conversions and, thereby, additional reductions in the demand for coal.

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 2014, we sold approximately 84.0% 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 2014, we derived approximately 25.1% of our total revenues from two customers and at least 10.0% of our 2014 total revenues from each of the two. If we were to lose either of these customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to decrease the amounts of coal purchased or 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:

- mining and processing equipment failures and unexpected maintenance problems;

- unavailability of required equipment;
- prices for fuel, steel, explosives and other supplies;
- fines and penalties incurred as a result of alleged violations of environmental and safety laws and regulations;
- variations in thickness of the layer, or seam, of coal;
- amounts of overburden, partings, rock and other natural materials;
- weather conditions, such as heavy rains, flooding, ice and other natural events affecting operations, transportation or customers;
- accidental mine water discharges and other geological conditions;
- fires;
- 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.

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

Effective October 1, 2014, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance, LLC (Wildcat Insurance). Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market at a reduced cost. The maximum limit in the commercial property program is $100.0 million per occurrence excluding a $1.5 million deductible for property damage, a 90 or 120-day waiting period for underground business interruption depending on the mining complex and a $10.0 million overall aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

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 do 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. At times, 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. A shortage of skilled labor could continue over an extended period and 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 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.

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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*.

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 Appalachia. EPA s action was ultimately upheld by a federal court. As a result of these developments, we may be unable to obtain or experience delays in securing, utilizing or renewing Section 404 permits required for our operations, which could have an adverse effect on our results of operation and financial position. Please read Item 1. Business 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 further reductions in transportation costs from western coal producing areas, the increased competition with certain eastern coal markets could have a material adverse effect on our business, financial condition and results of operations.

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

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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 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.

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 that 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 and securitization 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 and securitization facilities when they expire 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 that could also require significant amounts of financing that may not be available to us on acceptable terms or in the amounts we expect, or at all.

Various factors could adversely impact the debt and equity capital markets as well as our credit ratings or our ability to remain in compliance with the financial covenants under our then current debt agreements, which in turn could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth 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 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

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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.

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, 2014, our total long-term indebtedness outstanding was $821.3 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.

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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 20. Commitments and Contingencies for further discussion.

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 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, the Obama administration s budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration s proposal or other similar proposals could eliminate 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.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the amount of our common unit distributions and the value of an investment in our common units.

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.

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.

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 in determining unitholder s allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

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

A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing 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

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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 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, 2014, we had approximately 1.5 billion tons of coal reserves. Included in our total coal reserves are approximately 300.7 million tons of reserves located in Hamilton County, Illinois that 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 operations reflected in the following tables have been realigned as a result of a change in our reportable segment presentation in 2014. For additional information on the change in our reportable segment presentation, please read Item 8. Financial Statements and Supplementary Data Note 22. Segment Information.

The following table sets forth reserve information at December 31, 2014 about our mining operations:

			Proven and Probable Reserves Pounds S02 per MMBTU							
		Heat Content (BTUs per pound)					Reserve Assignment		Reserve Control	
Operations	Mine Type		<1.2	1.2-2.5	>2.5	Total	Assigned	Unassigned	Owned	Leased
				(tons in millions)						
Illinois Basin Operations										
Dotiki (KY)	Underground	12,000	-	-	90.4	90.4	42.0	48.4	30.2	60.2
Warrior (KY)	Underground	12,400	-	-	102.8	102.8	83.0	19.8	25.1	77.7
Hopkins (KY)	Underground	12,100	-	-	23.1	23.1	9.2	13.9	4.0	19.1
	/ Surface	11,500	-	-	7.8	7.8	7.8	-	7.8	-
River View (KY)	Underground	11,500	-	-	163.0	163.0	163.0	-	37.7	125.3
Henderson/Union (KY)	Underground	11,500	-	5.7	369.0	374.7	-	374.7	91.1	283.6

Onton (KY)	Underground	11,750	-	-	42.1	42.1	42.1	-	0.1	42.0
Sebree (KY)	Underground	11,400	-	-	29.7	29.7	-	29.7	3.8	25.9
Pattiki (IL)	Underground	11,500	-	-	54.9	54.9	14.8	40.1	-	54.9
Gibson (North) (IN)	Underground	11,500	0.1	12.1	14.3	26.5	26.5	-	0.7	25.8
Gibson (South) (IN)	Underground	11,500	1.1	26.8	48.2	76.1	76.1	-	21.6	54.5
Region Total			1.2	44.6	945.3	991.1	464.5	526.6	222.1	769.0
Appalachia Operations										
MC Mining (KY)	Underground	12,600	7.3	0.5	1.5	9.3	7.3	2.0	1.5	7.8
Mettiki (MD)	Underground	12,800	-	1.7	3.8	5.5	5.5	-	-	5.5
Mountain View (WV)	Underground	12,800	-	15.2	8.2	23.4	17.5	5.9	7.3	16.1
Tunnel Ridge (PA/WV)	Underground	12,600	-	-	83.4	83.4	83.4	-	-	83.4
Penn Ridge (PA)	Underground	12,500	-	-	56.7	56.7	56.7	-	-	56.7
Region Total			7.3	17.4	153.6	178.3	170.4	7.9	8.8	169.5
Total			8.5	62.0	1,098.9	1,169.4	634.9	534.5	230.9	938.5
% of Total			0.7%	5.3%	94.0%	100.0%	54.3%	45.7%	19.7%	80.3%

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The following table sets forth information related to reserves leased to White Oak at December 31, 2014:

			Proven and Probable Reserves Pounds S02 per MMBTU				Reserve Assignment		Reserve Control	
Operation	Mine Type	Heat Content (BTUs per pound)	<1.2	1.2-2.5	>2.5	Total	Assigned	Unassigned	Owned	Leased
				(tons in millions)						
Illinois Basin Operations										
White Oak (IL)	Underground	11,700	-	-	300.7	300.7	300.7	-	25.1	275.6

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

Reserve estimates will change from time to time to reflect mining activities, additional analysis, new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods, and other factors. Weir International Mining Consultants (Weir) performed an audit of our reserves and calculation methods in August 2010. Weir is expected to perform this audit again during 2015.

Reserves represent that part of a mineral deposit that can be economically and legally extracted or produced, and reflect estimated losses involved in producing a saleable product. All of our reserves are steam coal, except for reserves at Mettiki that can be delivered to the steam or metallurgical markets. The 7.3 million tons of reserves listed at MC Mining as <1.2 pounds of SO_2 per million British thermal units (MMBTU) are marketable as compliance coal under Phase II of CAA.

Assigned reserves are those reserves that have been designated for mining by a specific operation. Unassigned reserves are those reserves that have not yet been designated for mining by a specific operation. British thermal units (BTU) values are reported on an as shipped, fully washed basis. Shipments that are either fully or partially raw will have a lower BTU value.

We own or control certain leases for coal deposits that do not currently meet the criteria to be reserves but may be reclassified in the future. These tons are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits include the following: Mettiki 3.8 million tons, Tunnel Ridge 3.9 million tons, Penn Ridge 3.4 million tons, Warrior 8.1 million tons, Dotiki 1.6 million tons, Onton 4.6 million tons, Gibson (North) 0.1 million tons, Gibson (South) 1.3 million tons and Pattiki 13.9 million tons. In addition, the 2014 Henderson and Union Counties acquisitions account for 102.6 million tons of our non-reserve coal deposits and there are 4.6 million tons located near our Dotiki complex and 7.4 million tons leased to White Oak, for total non-reserve coal deposits of 155.3 million tons. For more information on reserve acquisitions see Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions.

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

Tons produced from reserves leased to third parties are not included in the amounts of produced tons that we report, as shown in the below table.

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Mining Operations

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

Operations	Location	2014	2013	2012	Transportation	Equipment
			Tons Produced (in millions)			
Illinois Basin Operations						
Dotiki	Kentucky	3.9	3.5	3.4	CSX, PAL, truck, barge	CM
Warrior	Kentucky	5.1	5.9	5.9	CSX, PAL, truck, barge	CM
Hopkins	Kentucky	3.0	3.1	3.1	CSX, PAL, truck, barge	CM, TS
River View	Kentucky	9.3	9.3	8.6	Barge	CM
Onton	Kentucky	2.4	2.4	1.6	Barge, truck	CM
Pattiki	Illinois	2.6	2.6	2.4	CSX, EVWR, barge	CM
Gibson (North)	Indiana	3.8	3.9	3.4	CSX, NS, truck, barge	CM
Gibson (South)	Indiana	0.8	-	-	CSX, NS, truck, barge	CM
Region Total		30.9	30.7	28.4		
Appalachia Operations						
MC Mining	Kentucky	1.6	1.3	1.3	CSX, truck, barge	CM
Mettiki	Maryland	-	0.1	0.2	Truck, CSX	CM
Mountain View	West Virginia	1.9	2.3	2.3	Truck, CSX	LW, CM
Tunnel Ridge	West Virginia	6.3	3.7	2.0	Barge, WLE	LW, CM
Region Total		9.8	7.4	5.8		
Other Operations						
Pontiki	Kentucky	-	0.7	0.6	NS, truck, barge	CM
Region Total		-	0.7	0.6		
TOTAL		40.7	38.8	34.8		

CSX	- CSX Railroad
NS	- Norfolk Southern Railroad
PAL	- Paducah & Louisville Railroad
CM	- Continuous Miner
LW	- Longwall
EVWR	- Evansville Western Railroad
WLE	- Wheeling & Lake Erie Railroad
TS	- Truck, Shovel, Front End Loader or Dozer

ITEM 3. LEGAL PROCEEDINGS

From time to time we are party to litigation matters incidental to the conduct of our business. We initiated litigation on January 15, 2015 alleging that a customer anticipatorily breached a coal supply contract when it notified us that it would not accept coal shipments under the contract after April 15, 2015. (Tunnel Ridge, LLC v. Allegheny Energy Supply Company, LLC, Court of Common Pleas, Allegheny County, Pennsylvania.) The contract obligates the customer to purchase more than 5.0 million tons during the period between April 16, 2015 and the end of the contract term on December 31, 2021. We are seeking to recover damages resulting from the customer s alleged breach of contract.

It is the opinion of management that the ultimate resolution of our pending litigation matters will not have a material adverse effect on our financial condition, results of operation or liquidity. However, we cannot assure you that disputes or litigation will not arise or that we will be able to resolve any such future disputes or litigation in a satisfactory manner. The information under General Litigation and Other in Item 8. Financial Statements and Supplementary Data Note 20. Commitments and Contingencies is incorporated herein by this reference.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Annual Report on Form 10-K.

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PART II

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

The common units representing limited partners interests are listed on the NASDAQ Global Select Market under the symbol ARLP. The common units began trading on August 20, 1999. On February 13, 2015, the closing market price for the common units was $39.29 per unit. As of February 13, 2014, there were 74,188,784 common units outstanding. There were approximately 39,627 record holders of common units at December 31, 2014.

The following table sets forth the range of high and low sales prices per common unit and the amount of cash distributions declared and paid with respect to the units, for the two most recent fiscal years:

	High (1)	**Low (1)**	**Distributions Per Unit**
1st Quarter 2013	$33.23	$29.28	$0.565 (paid May 15, 2013)
2nd Quarter 2013	$39.25	$31.28	$0.57625 (paid August 14, 2013)
3rd Quarter 2013	$39.50	$35.00	$0.5875 (paid November 14, 2013)
4th Quarter 2013	$39.00	$34.00	$0.59875 (paid February 14, 2014)
1st Quarter 2014	$43.38	$37.51	$0.61125 (paid May 15, 2014)
2nd Quarter 2014	$48.02	$41.08	$0.625 (paid August 14, 2014)
3rd Quarter 2014	$53.84	$41.56	$0.6375 (paid November 14, 2014)
4th Quarter 2014	$50.02	$37.08	$0.65 (paid February 13, 2015)

(1) We completed a two-for-one unit split on June 16, 2014. Trading prices and distributions per unit for periods prior to the completion of the unit split have been adjusted to give effect to the unit split.

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

Under the quarterly incentive distribution provisions of the partnership agreement, our managing general partner is entitled to receive 15% of the amount we distribute in excess of $0.1375 per unit, 25% of the amount we distribute in excess of $0.15625 per unit, and 50% of the amount we distribute in excess of $0.1875 per unit.

Equity Compensation Plans

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

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ITEM 6. SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2014, 2013, 2012, 2011 and 2010.

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

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Statements of Income					
Sales and operating revenues:					
Coal sales	$ 2,208.6	$ 2,137.4	$ 1,979.4	$ 1,786.1	$ 1,551.5
Transportation revenues	26.0	32.6	22.0	31.9	33.6
Other sales and operating revenues	66.1	35.5	32.9	25.6	24.9
Total revenues	2,300.7	2,205.5	2,034.3	1,843.6	1,610.0
Expenses:					
Operating expenses (excluding depreciation, depletion and amortization)	1,383.4	1,398.8	1,303.3	1,131.8	1,009.9
Transportation expenses	26.0	32.6	22.0	31.9	33.6
Outside coal purchases	-	2.0	38.6	54.3	17.1
General and administrative	72.5	63.7	58.8	52.3	50.8
Depreciation, depletion and amortization	274.6	264.9	218.1	160.3	146.9
Asset impairment charge	-	-	19.0	-	-
Total operating expenses	1,756.5	1,762.0	1,659.8	1,430.6	1,258.3
Income from operations	544.2	443.5	374.5	413.0	351.7
Interest expense (net of interest capitalized)	(33.6)	(27.0)	(28.7)	(22.0)	(30.1)
Interest income	1.7	1.0	0.2	0.4	0.2
Equity in loss of affiliates, net	(16.7)	(24.4)	(14.7)	(3.4)	-
Other income	1.6	1.8	3.2	1.0	0.9
Income before income taxes	497.2	394.9	334.5	389.0	322.7
Income tax expense (benefit)	-	1.4	(1.1)	(0.4)	1.7
Net income	497.2	393.5	335.6	389.4	321.0
Less: Net loss attributable to noncontrolling interest	-	-	-	-	-
Net income attributable to Alliance Resource Partners, L.P. (Net Income of ARLP)	$ 497.2	$ 393.5	$ 335.6	$ 389.4	$ 321.0
General Partners interest in Net Income of ARLP	$ 138.3	$ 121.4	$ 106.8	$ 86.3	$ 73.2
Limited Partners interest in Net Income of ARLP	$ 358.9	$ 272.1	$ 228.8	$ 303.1	$ 247.8
Basic and diluted net income of ARLP per limited partner unit (1)	$ 4.77	$ 3.63	$ 3.06	$ 4.06	$ 3.34
Distributions paid per limited partner unit	$ 2.4725	$ 2.2825	$ 2.08125	$ 1.81375	$ 1.6025
Weighted-average number of units outstanding-basic and diluted	74,044,417	73,904,384	73,726,044	73,538,252	73,420,862
Balance Sheet Data:					
Working capital (2)	$ (80.0)	$ 109.4	$ 73.0	$ 269.3	$ 348.7
Total assets	2,285.1	2,121.9	1,956.0	1,731.5	1,501.3
Long-term obligations (3)	606.9	848.4	791.6	688.5	704.2
Total liabilities	1,270.0	1,270.7	1,250.5	1,107.8	1,045.5
Partners capital	$ 1,051.1	$ 851.2	$ 705.5	$ 623.7	$ 455.8
Other Operating Data:					
Tons sold	39.7	38.8	35.2	31.9	30.3

Tons produced		40.7		38.8		34.8		30.8		28.9
Coal sales per ton sold (4)	$	55.59	$	55.04	$	56.28	$	55.95	$	51.21
Cost per ton sold (5)	$	34.82	$	36.07	$	38.15	$	37.15	$	33.90
Other Financial Data:										
Net cash provided by operating activities	$	739.2	$	704.7	$	555.9	$	574.0	$	520.6
Net cash used in investing activities		(441.2)		(426.0)		(623.4)		(401.1)		(295.0)
Net cash provided by (used in) financing activities		(367.0)		(213.3)		(177.7)		(238.9)		92.7
EBITDA (6)		803.7		685.9		581.1		570.8		499.5
Maintenance capital expenditures (7)		236.3		222.4		282.6		192.7		90.5

(1) Diluted earnings per unit (EPU) gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive units calculated under the treasury stock method if their effect is anti-dilutive. For the year ended December 31, 2014, 2013, 2012 and 2011, long-term incentive plan (LTIP), Supplemental Executive Retirement Plan (SERP) and Directors compensation units of 798,701, 682,746, 689,912 and 819,938, respectively, were considered anti-dilutive. For the years ended December 31, 2010, LTIP units of 464,084, respectively, were considered anti-dilutive.

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(2) Working capital is impacted by current maturities of long term debt, which at December 31, 2014, included Series A Senior notes. For information regarding long-term debt, please read Item 8. Financial Statements and Supplementary Data Note 7. Long-Term Debt of this Annual Report on Form 10-K.

(3) Long-term obligations include long-term portions of debt and capital lease obligations.

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

(5) Cost per ton sold is based on the total of operating expenses and outside coal purchases divided by tons sold.

(6) EBITDA is a financial measure not calculated in accordance with generally accepted accounting principles (GAAP) and is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on investment compared to those of other companies in the coal energy sector, without regard to financing or capital structures; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

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

[redacted]

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

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

General

The following discussion of our financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, please see Item 8. Financial Statements and Supplementary Data Note 1. Organization and Presentation and Note 2. Summary of Significant Accounting Policies.

Executive Overview

We are a diversified producer and marketer of coal primarily to major U.S. utilities and industrial users. In 2014, we produced and sold a record 40.7 million and 39.7 million tons of coal, respectively. The coal we produced in 2014 was approximately 4.0% low-sulfur coal, 16.0% medium-sulfur coal and 80.0% high-sulfur coal. 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, including the Gibson South mine, which began initial production in April 2014. We operate a coal-loading terminal on the Ohio River at Mt. Vernon, Indiana. We own a preferred equity interest in White Oak and purchased and funded development of coal reserves, and operate surface facilities at White Oak s new mining complex in southern Illinois. Please see Item 1. Business Mining Operations for further discussion of our mines. Beginning in November 2014, we now own through our consolidated affiliate, Cavalier Minerals, an equity interest and plan to make additional equity investments in AllDale Minerals for the purchase of oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. For more information on our White Oak and AllDale Minerals investments, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments . At December 31, 2014, we had approximately 1.5 billion tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia compared to 1.1 billion tons at December 31, 2013. Approximately 300.7 million tons of those reserves are leased to White Oak. For more information on our increase in reserves, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions. We believe we control adequate reserves to implement our currently contemplated mining plans.

In 2014, approximately 95.6% of our sales tonnage was purchased by electric utilities, with the balance sold to third-party resellers and industrial consumers. In 2014, approximately 84.0% of our sales tonnage was sold under long-term contracts. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2014, approximately 95.7% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices. These devices, also known as scrubbers, eliminate substantially all emissions of sulfur dioxide.

As discussed in more detail in Item 1A. Risk Factors, our results of operations could be impacted by prices for items that are used in coal production such as steel, electricity and other supplies, unforeseen geologic conditions or mining and processing equipment failures and unexpected maintenance problems, and by the availability or reliability of transportation for coal shipments. Additionally, our results of operations could be impacted by our ability to obtain and renew permits necessary for our operations, secure or acquire coal reserves, or find replacement buyers for coal under contracts with comparable terms to existing contracts. Moreover, the regulatory environment has grown increasingly stringent in recent years. As outlined in Item 1. Business Regulation and Laws, a variety of measures taken by regulatory agencies in the U.S. and abroad in response to the perceived threat from climate change attributed to GHG emissions could substantially increase compliance costs for us and our customers and reduce demand for coal, which could materially and adversely impact our results of operations. For additional information regarding some of the risks and uncertainties that affect our business and the industry in which we operate, see Item 1A. Risk Factors.

Our principal expenses related to the production of coal are labor and benefits, equipment, materials and supplies, maintenance, royalties and excise taxes. Unlike many of our competitors in the eastern U.S., we employ a totally union-free workforce. Many of the benefits of our union-free workforce are related to higher productivity and are not necessarily reflected in our direct costs. In addition, transportation costs may be substantial and are often the determining factor in a coal consumer s contracting decision. Our mining operations are located near many of the major eastern utility generating plants and on major coal hauling railroads in the eastern U.S. Our River View and Tunnel

Ridge mines and Mt. Vernon transloading facility are located on the Ohio River and our Onton mine is located on the Green River in western Kentucky.

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

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

We have four reportable segments: the Illinois Basin, Appalachia, White Oak and Other and Corporate. The first two reportable segments correspond to major coal producing regions in the eastern U.S. Factors similarly affecting financial performance of our operating segments within each of these two reportable segments generally include coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues. The White Oak reportable segment is comprised of our activities associated with the White Oak Mine No. 1 in southern Illinois, which commenced initial longwall operation in late October 2014 and is more fully described below.

- *Illinois Basin* reportable segment is comprised of multiple operating segments, including Webster County Coal s Dotiki mining complex, Gibson County Coal s mining complex, which includes the Gibson North mine and Gibson South mine, Hopkins County Coal s mining complex, which includes the Elk Creek mine and the Fies property, White County Coal s Pattiki mining complex, Warrior s mining complex, Sebree Mining s mining complex, which includes the Onton mine, Steamport and certain Sebree Reserves, River View s mining complex, CR Services, LLC, and certain properties of Alliance Resource Properties, ARP Sebree, LLC (ARP Sebree) and ARP Sebree South, LLC. In April 2014, initial production began at the Gibson South mine. The Elk Creek mine is currently expected to cease production in early 2016. The Sebree Mining and Fies properties are held by us for future mine development. In December 2014, Alliance Resource Properties acquired reserves that will significantly extend the life of the Dotiki mine, allow increased production from our River View mine and add three new potential development projects for our organic growth strategy. For information regarding the permitting process and matters that could hinder or delay the process, please read Item 1. Business Regulation and Laws *Mining Permits and Approvals* and for information regarding the acquisition of reserves in December 2014 and the acquisition of the Onton mine that was added to the Illinois Basin segment in April 2012, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K.

- *Appalachia* reportable segment is comprised of multiple operating segments, including the Mettiki mining complex, the Tunnel Ridge mining complex, the MC Mining mining complex and the Penn Ridge property. The Mettiki mining complex includes Mettiki (WV) s Mountain View mine, Mettiki (MD) s preparation plant and a small third-party mining operation, which has been idled since July 2013. In June 2013, Alliance Resource Properties acquired reserves that extended the life of the Mettiki (WV) Mountain View mine. For information regarding the reserves acquired, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K. In May 2012, longwall production began at the Tunnel Ridge mine. We are in the process of permitting the Penn Ridge property for future mine development. For information regarding the permitting process and matters that could hinder or delay the process, please read Item 1.

Business Regulation and Laws *Mining Permits and Approvals.*

- *White Oak* reportable segment is comprised of two operating segments, WOR Processing and WOR Properties. WOR Processing includes both the surface operations we are operating at the White Oak mining complex and our equity investments in White Oak. WOR Properties owns coal reserves acquired from White Oak and is committed to acquiring additional reserves from White Oak under lease-back arrangements. WOR Properties has also provided certain funding to White Oak for development of these reserves. The White Oak reportable segment also includes two loans to White Oak from our Intermediate Partnership, one for the acquisition of mining equipment (which was repaid and terminated in June 2012) and another to construct certain surface facilities. For more information on White Oak, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

- *Other and Corporate* segment includes marketing and administrative expenses, Alliance Service, Inc. (ASI) and its subsidiary, Matrix Group, ASI s ownership of aircraft, the Mt. Vernon dock activities, coal brokerage activity, our equity investment in MAC, certain activities of Alliance Resource Properties, the Pontiki mining complex, which ceased operations in November 2013 and sold most of its assets in May 2014, Wildcat Insurance, Alliance Minerals and its affiliate, Cavalier Minerals, which holds an equity investment in AllDale Minerals, and AROP Funding, LLC (AROP Funding). Please read Item 8. Financial Statements and Supplementary Data Note 19. Related-Party Transactions for more information on ASI, Alliance Minerals, Cavalier Minerals and AllDale Minerals and Item 8. Financial Statements and Supplementary Data Note 4. Asset Impairment Charge for more information on Pontiki of this Annual Report on Form 10-K.

How We Evaluate Our Performance

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

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

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

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

EBITDA. We define EBITDA (a non-GAAP financial measure) as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;

- our operating performance and return on investment compared to those of other companies in the coal energy sector, without regard to financing or capital structures; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

Analysis of Historical Results of Operations

2014 Compared with 2013

We reported record net income of $497.2 million for 2014 compared to $393.5 million for 2013. The increase of $103.7 million was principally due to increased sales from low-cost production at our Tunnel Ridge mine in addition to record coal sales and production volumes, which rose to 39.7 million tons sold and 40.7 million tons produced in 2014 compared to 38.8 million tons sold and produced in 2013. The increase in tons sold and produced resulted primarily from increased production as a result of improved mining conditions at our Tunnel Ridge, MC Mining and Dotiki mines and the start-up of coal production at our Gibson South mine in April 2014. Record net income also benefited from throughput fees received from surface facility services and coal royalties related to operations at the White Oak Mine No. 1. Lower operating expenses during 2014 resulted primarily from a coal inventory build during the year; improved productivity at our Tunnel Ridge, MC Mining and Dotiki mines; a significant increase in sales of lower-cost production from Tunnel Ridge; insurance proceeds received in 2014 related to the previously mentioned adverse geological event at our Onton mine that also increased operating expenses in 2013; the idling of a higher-cost third-party mining operation at our Mettiki mine; and the absence of higher-cost production at our Pontiki mine, which was closed in late 2013.

	December 31,				December 31,			
	2014		2013		2014		2013	
	(in thousands)				(per ton sold)			
Tons sold		39,731		38,835		N/A		N/A
Tons produced		40,749		38,782		N/A		N/A
Coal sales	$	2,208,611	$	2,137,449	$	55.59	$	55.04
Operating expenses and outside coal purchases	$	1,383,374	$	1,400,793	$	34.82	$	36.07

Coal sales. Coal sales increased 3.3% to $2.2 billion in 2014 from $2.1 billion in 2013. The increase of $71.2 million reflected the benefit of record tons sold (contributing $49.3 million in additional coal sales) and higher average coal sales prices (contributing $21.9 million in additional coal sales). Average coal sales prices increased $0.55 per ton sold in 2014 to $55.59 per ton compared to $55.04 per ton sold in 2013, primarily as a result of increased contract pricing at our Mettiki mine, an increase of higher-priced coal sales at our Tunnel Ridge mine and the addition of higher-priced coal sales at our new Gibson South mine, offset partially by the absence of higher-priced Pontiki sales in 2014.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases decreased 1.2% to $1.4 billion in 2014. On a per ton basis, operating expenses and outside coal purchases decreased 3.5% to $34.82 per ton from $36.07 per ton sold in 2013, primarily due to increased lower-cost production at our Tunnel Ridge mine, strong production performance at our MC Mining and Dotiki mines, improved production and operating conditions at our Onton mine and the absence of higher-cost production at our Pontiki mine discussed above. Operating expenses were impacted by various other factors, the most significant of which are discussed below:

- Labor and benefit expenses per ton produced, excluding workers compensation, decreased 2.7% to $11.72 per ton in 2014 from $12.04 per ton in 2013. The decrease of $0.32 per ton was primarily attributable to lower labor cost per ton resulting from increased production discussed above, lower medical expenses at the Mettiki mine and the absence of higher-cost per ton labor and benefits at our Pontiki mine;

- Materials and supplies expenses per ton produced decreased slightly to $11.60 per ton in 2014 from $11.63 per ton in 2013. The decrease of $0.03 per ton produced resulted primarily from increased production discussed above and a decrease in cost for certain products and services, primarily safety related materials and supplies (decrease of $0.09 per ton), lower longwall subsidence expense (decrease of $0.04 per ton) offset partially by increased roof supports (increase of $0.06 per ton) and ventilation-related materials and supplies (increase of $0.05 per ton);

- Maintenance expenses per ton produced decreased 2.5% to $3.90 per ton in 2014 from $4.00 per ton in 2013. The decrease of $0.10 per ton produced was primarily from the benefits of increased production at certain locations, as discussed above, and the absence of higher-cost per ton maintenance expenses at our Pontiki mine;

- Contract mining expenses decreased $4.8 million in 2014 compared to 2013. The decrease primarily reflects lower production resulting from the idling of a third-party mining operation at our Mettiki mine complex in 2013 due to reduced metallurgical coal export market opportunities;

- Operating expenses benefited from insurance proceeds of $7.0 million received in 2014 related to claims from the adverse geological event at the Onton mine in 2013 and the absence of $3.8 million of asset retirements that occurred in 2013 resulting from the Onton mine s previously mentioned adverse geological event.

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Operating expenses and outside coal purchases per ton decreases discussed above were partially offset by the following increase:

- Workers compensation and black lung expenses per ton produced increased to $0.30 per ton in 2014 from $0.17 per ton in 2013. The increase of $0.13 per ton resulted primarily from a decrease in the discount rate used to calculate the estimated present value of future obligations and reduced favorable claim trends and disability incident rate assumptions in 2014 compared to 2013.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, Matrix Design sales, throughput fees received from White Oak and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to $66.1 million in 2014 from $35.5 million in 2013. The increase of $30.6 million was primarily attributable to White Oak throughput fees and payments in lieu of shipments received from a customer in 2014 related to an Appalachian coal sales contract.

General and administrative. General and administrative expenses for 2014 increased to $72.6 million compared to $63.7 million in 2013. The increase of $8.9 million was primarily due to increased compensation-related expenses.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $274.6 million in 2014 compared to $264.9 million in 2013. The increase of $9.7 million was primarily attributable to record production volumes mentioned above, as well as capital expenditures related to production expansion and infrastructure investments at various operations.

Interest expense. Interest expense, net of capitalized interest, increased to $33.6 million in 2014 from $27.0 million in 2013. The increase of $6.6 million was principally attributable to decreased capitalized interest on our equity investment in White Oak, partially offset by decreased interest resulting from principal repayments made during 2014 of $18.8 million and $18.0 million on our term loan and original senior notes issued in 1999, respectively. The term loan and senior notes are discussed in more detail below under Debt Obligations.

Equity in loss of affiliates, net. Equity in loss of affiliates, net includes our share of the results of operations of our equity investments in White Oak, AllDale Minerals and MAC. Equity in loss of affiliates, net was $16.6 million in 2014 compared to $24.4 million in 2013. The decrease in net equity in loss of affiliates is primarily related to our equity investment in White Oak and the impact of changes in allocations of equity income or losses resulting from equity contributions during 2014 by another White Oak owner, partially offset by increased losses incurred by White Oak during 2014. Equity contributions impact the future preferred distributions allocable to each owner and the ongoing allocation of income and losses for GAAP purposes. For more information regarding White Oak, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

Transportation revenues and expenses. Transportation revenues and expenses decreased to $26.0 million in 2014 from $32.6 million in 2013. The decrease of $6.6 million was primarily attributable to a decrease in average transportation rates reflecting the absence of export sales to a certain customer from our Warrior mine in 2014 compared to 2013, as well as decreased tonnage for which we arranged transportation at certain other mines in 2014. The cost of transportation services are passed through to our customers. Consequently, we do not realize any gain or loss on transportation revenues.

Income tax expense. Income tax expense decreased $1.4 million in 2014. Income taxes are primarily due to the operations of Matrix Design. The decrease in income tax expense was primarily due to a large valuation allowance of ASI s deferred tax assets in 2013.

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Segment Information. Our 2014 Segment Adjusted EBITDA increased 16.9% to $876.2 million from 2013 Segment Adjusted EBITDA of $749.6 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows (in thousands):

	Year Ended December 31, 2014	2013	Increase (Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 620,111	$ 657,404	$ (37,293)	(5.7)%
Appalachia (4)	254,037	105,123	148,914	(1)
White Oak	(3,384)	(25,229)	21,845	86.6%
Other and Corporate (4)	8,599	12,278	(3,679)	(30.0)%
Elimination	(3,119)	-	(3,119)	(1)
Total Segment Adjusted EBITDA (2)	$ 876,244	$ 749,576	$ 126,668	16.9%
Tons sold				
Illinois Basin	30,549	30,640	(91)	(0.3)%
Appalachia (4)	9,182	7,493	1,689	22.5%
White Oak	-	-	-	-
Other and Corporate (4)	-	775	(775)	(1)
Elimination (4)	-	(73)	73	(1)
Total tons sold	39,731	38,835	896	2.3%
Coal sales				
Illinois Basin	$ 1,609,094	$ 1,605,232	$ 3,862	0.2%
Appalachia (4)	599,262	476,736	122,526	25.7%
White Oak	-	-	-	-
Other and Corporate (4)	255	60,073	(59,818)	(99.6)%
Elimination (4)	-	(4,592)	4,592	(1)
Total coal sales	$ 2,208,611	$ 2,137,449	$ 71,162	3.3%
Other sales and operating revenues				
Illinois Basin	$ 3,062	$ 3,858	$ (796)	(20.6)%
Appalachia (4)	19,464	4,310	15,154	(1)
White Oak	21,244	2,194	19,050	(1)
Other and Corporate (4)	33,834	38,199	(4,365)	(11.4)%
Elimination	(11,515)	(13,091)	1,576	12.0%
Total other sales and operating revenues	$ 66,089	$ 35,470	$ 30,619	86.3%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 992,045	$ 951,686	$ 40,359	4.2%
Appalachia (4)	364,689	375,923	(11,234)	(3.0)%
White Oak	7,983	2,112	5,871	(1)
Other and Corporate (4)	25,487	86,864	(61,377)	(70.7)%
Elimination (4)	(8,396)	(17,683)	9,287	52.5%
Total Segment Adjusted EBITDA Expense (3)	$ 1,381,808	$ 1,398,902	$ (17,094)	(1.2)%

(1) Percentage change was greater than or equal to 100%.

(2) Segment Adjusted EBITDA (a non-GAAP financial measure) is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization and general and administration expenses. Segment Adjusted

EBITDA is a key component of consolidated EBITDA, which is used as a supplemental financial measure by management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

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- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on investment compared to those of other companies in the coal energy sector, without regard to financing or capital structures; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

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

	Year Ended December 31, 2014	2013
Consolidated Segment Adjusted EBITDA	$ 876,244	$ 749,576
General and administrative	(72,552)	(63,697)
Depreciation, depletion and amortization	(274,566)	(264,911)
Interest expense, net	(31,913)	(26,082)
Income tax expense	-	(1,396)
Net income	$ 497,213	$ 393,490

(3) Segment Adjusted EBITDA Expense (a non-GAAP financial measure) includes operating expenses, outside coal purchases and other income. Transportation expenses are excluded as these expenses are passed through to our customers and, consequently, we do not realize any gain or loss on transportation revenues. Segment Adjusted EBITDA Expense is used as a supplemental financial measure by our management to assess the operating performance of our segments. In our evaluation of EBITDA, which is discussed above under *How We Evaluate Our Performance*, Segment Adjusted EBITDA Expense is a key component of Segment Adjusted EBITDA in addition to coal sales and other sales and operating revenues. The exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA Expense allows management to focus solely on the evaluation of segment operating performance as it primarily relates to our operating expenses. Outside coal purchases are included in Segment Adjusted EBITDA Expense because tons sold and coal sales include sales from outside coal purchases.

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

	Year Ended December 31, 2014	2013

Segment Adjusted EBITDA Expense	$	1,381,808	$	1,398,902
Outside coal purchases		(14)		(2,030)
Other income		1,566		1,891
Operating expenses (excluding depreciation, depletion and amortization)	$	1,383,360	$	1,398,763

(4) In 2014, we realigned our segment presentation. The Appalachia segment is now comprised of the MC Mining, Mettiki and Tunnel Ridge mines. Results for the Pontiki mine, which ceased operations in November 2013, are now reflected in the Other and Corporate segment. Reclassifications of the 2013 segment information have been made to the Appalachia and Other and Corporate segments, as well as eliminations above to conform to the 2014 presentation.

Illinois Basin Segment Adjusted EBITDA decreased 5.7% to $620.1 million in 2014 from $657.4 million in 2013. The decrease of $37.3 million was primarily attributable to decreased coal recoveries at our Warrior mine as it continues to transition into a new mining area and increased expenses per ton at our Pattiki and Hopkins mines due to difficult mining conditions, partially offset by improved sales and production from our Dotiki mine and improved production and operating conditions at our Onton mine. Also benefiting 2014 were higher average coal sales prices that increased slightly to $52.67 per ton sold compared to $52.39 per ton in 2013. Coal sales increased $3.9 million to $1.6 billion in 2014 primarily reflecting increased tons sold from our Dotiki mine and higher-priced coal sales from start-up production at our Gibson South mine, partially offset by reduced tons sold at our Warrior and Gibson North mines. Segment Adjusted EBITDA Expense increased 4.2% to $992.0 million in 2014 from $951.7 million in 2013 and increased $1.41 per ton sold to $32.47 from $31.06 per ton sold in 2013, primarily as a result of difficult mining conditions and lower recoveries discussed above. The increase in Segment Adjusted EBITDA Expense was partially offset by insurance proceeds received in 2014 related to the impact of the adverse geological event at our Onton mine in 2013 mentioned above, as well as certain other cost decreases discussed above under Operating expenses and outside coal purchases .

Appalachia Segment Adjusted EBITDA increased to $254.0 million for 2014 compared to $105.1 million for 2013. The increase of $148.9 million was primarily attributable to increased tons sold, which rose 22.5% to 9.2 million tons sold, and higher average coal sales prices of $65.26 per ton sold during 2014 compared to $63.62 per ton sold during 2013. Coal sales increased 25.7% to $599.3 million in 2014 compared to $476.7 million in 2013. The increase of $122.6 million was primarily due to increased production at our Tunnel Ridge and MC Mining operations and higher contract coal sales prices at our Mettiki mine. Segment Adjusted EBITDA also benefited from increased other sales and operating revenues due to payments in lieu of shipments received from a customer in 2014. Segment Adjusted EBITDA Expense decreased 3.0% to $364.7 million in 2014 from $375.9 million in 2013 and decreased $10.45 per ton sold to $39.72 from $50.17 per ton sold in 2013, primarily due to improved productivity and geological conditions at our Tunnel Ridge mine and new Excel No. 4 mining area at the MC Mining operation, reduced contract mining expenses and lower employee benefit cost at our Mettiki mining complex, as well as certain other cost decreases discussed above under Operating expenses and outside coal purchases .

White Oak Segment Adjusted EBITDA was $(3.4) million and $(25.2) million in 2014 and 2013, respectively, primarily attributable to losses allocated to us due to our equity interest in White Oak. We were allocated $16.6 million and $25.3 million in losses for 2014 and 2013, respectively. Segment Adjusted EBITDA for 2014 was favorably impacted by reduced allocation of losses to us as a result of equity contributions made by another White Oak owner as discussed above under Equity in loss of affiliates, net. We also received throughput revenues for surface facility services and coal royalties of $21.2 million and $2.2 million for 2014 and 2013, respectively. For more information on White Oak, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

Other and Corporate Segment Adjusted EBITDA decreased $3.7 million in 2014 from 2013 and Segment Adjusted EBITDA Expense decreased 70.7% to $25.5 million for 2014. These decreases were primarily attributable to the absence of production and sales in 2014 from our former Pontiki mine discussed above.

2013 Compared with 2012

We reported record net income of $393.5 million for 2013 compared to $335.6 million for 2012. This increase of $57.9 million was principally due to record coal sales and production volumes. We had record tons sold and tons produced of 38.8 million in 2013 compared to 35.2 million tons sold and 34.8 million tons produced in 2012. Also negatively impacting 2012 was the temporary idling of our Pontiki mining complex and the related non-cash impairment charge of $19.0 million. The increase in tons sold and produced resulted from increased production at the Tunnel Ridge mine, which began longwall production in May 2012, increased tons produced and sold from our River View and Gibson North mines and increased production from the Onton mine, which was acquired in April 2012. Higher operating expenses during 2013 resulted primarily from the record coal sales and production volumes, which particularly impacted labor and related benefits expenses, materials and supplies expenses, maintenance costs and sales-related expenses. These increases in operating expenses were offset partially by lower workers compensation expense and reduced outside coal purchases in 2013.

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	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
	(in thousands)		(per ton sold)	
Tons sold	38,835	35,170	N/A	N/A
Tons produced	38,782	34,800	N/A	N/A
Coal sales	$ 2,137,449	$ 1,979,437	$ 55.04	$ 56.28
Operating expenses and outside coal purchases	$ 1,400,793	$ 1,341,898	$ 36.07	$ 38.15

Coal sales. Coal sales increased 8.0% to $2.1 billion in 2013 from $2.0 billion in 2012. The increase of $158.0 million reflected the benefit of record tons sold (contributing $206.3 million in additional coal sales), partially offset by lower average coal sales prices (reducing coal sales by $48.3 million). Average coal sales prices decreased $1.24 per ton sold in 2013 to $55.04 per ton compared to $56.28 per ton sold in 2012, primarily due to reduced coal sales into the metallurgical coal export market.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases increased 4.4% to $1.4 billion in 2013 from $1.3 billion in 2012 primarily due to record coal sales and production volumes. On a per ton basis, operating expenses and outside coal purchases decreased 5.5% to $36.07 per ton sold from $38.15 in 2012. In addition to the impact of record volumes, operating expenses were impacted by various other factors, the most significant of which are discussed below:

- Labor and benefit expenses per ton produced, excluding workers compensation, decreased 3.5% to $12.04 per ton in 2013 from $12.48 per ton in 2012. The decrease of $0.44 per ton was primarily attributable to lower labor cost per ton resulting from increased production at our Tunnel Ridge mine, which began longwall production in May 2012, improved coal recoveries at our River View and Gibson North mines, improved geological conditions at our Dotiki and Pattiki mines and lower labor cost per ton at our Onton mine despite a temporary halt of production during the third quarter of 2013 due to adverse geological conditions. Costs per ton increased at our Mettiki mine, primarily due to higher medical-related employee benefits expense;

- Workers compensation and black lung expenses per ton produced decreased to $0.17 per ton in 2013 from $0.70 per ton in 2012. The decrease of $0.53 per ton resulted primarily from an increase in the discount rate used to calculate the estimated present value of future obligations and favorable claim trends;

- Material and supplies expenses per ton produced decreased to $11.63 per ton in 2013 from $12.46 per ton in 2012. The decrease of $0.83 per ton resulted from lower costs for certain products and services, primarily outside services (decrease of $0.24 per ton), contract labor used in the mining process (decrease of $0.16 per ton), certain ventilation-related materials and supplies (decrease of $0.12 per ton), power and fuel used in the mining process (decrease of $0.09 per ton) and roof support expenses per ton (decrease of $0.09 per ton) in addition to production increases at certain locations discussed above;

- Maintenance expenses per ton produced decreased 3.1% to $4.00 per ton in 2013 from $4.13 per ton in 2012. The decrease of $0.13 per ton produced was primarily from the benefits of newer equipment and increased production at our Tunnel Ridge mine and improved coal recoveries at certain locations as discussed above;

- Contract mining expenses decreased $6.7 million in 2013 compared to 2012. The decrease primarily reflects lower production from a third-party mining operation in our Appalachian region due to reduced metallurgical coal export market opportunities;

- Production taxes and royalties (which were incurred as a percentage of coal sales or based on coal volumes) decreased $0.17 per produced ton sold in 2013 compared to 2012, primarily resulting from a lower average coal sales prices for Appalachia due to reduced coal sales into the metallurgical coal export market; and

- Outside coal purchases decreased to $2.0 million in 2013 from $38.6 million in 2012. The decrease of $36.6 million was primarily attributable to decreased coal brokerage activity and less coal purchased to facilitate sales into the metallurgical coal export market. The cost per ton to purchase coal is typically higher than our cost per ton to produce coal, thus significantly lower volumes of coal purchases, like in 2013, generally reduce our overall total expense per ton.

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Operating expenses and outside coal purchases per ton decreases discussed above were partially offset by the following increase:

- Capitalized development related to the construction of our new Tunnel Ridge mine ceased in May 2012 with the start-up of longwall production. Accordingly, the above discussed operating expense decreases in 2013 were offset partially by the capitalization of $19.0 million of mine development costs at Tunnel Ridge in 2012. Please read Item 8. Financial Statements and Supplementary Data Note 2. Summary of Significant Accounting Policies of this Annual Report on Form 10-K for discussion of capitalized mine development costs.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, Matrix Design sales, throughput fees received from White Oak and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to $35.5 million in 2013 from $32.8 million in 2012. The increase of $2.7 million was primarily attributable to increased Matrix Design sales, Mt. Vernon transloading revenues and White Oak throughput fees, partially offset by the amounts received from a customer for the partial buy-out of a certain Appalachian coal contract in 2012.

General and administrative. General and administrative expenses for 2013 increased to $63.7 million compared to $58.7 million in 2012. The increase of $5.0 million was primarily due to higher incentive compensation expenses.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $264.9 million in 2013 compared to $218.1 million in 2012. The increase of $46.8 million was primarily attributable to the start-up of longwall production at the Tunnel Ridge mine, which began in May 2012, the addition of the Onton mine in April 2012 and capital expenditures related to production and infrastructure improvements at various other operations.

Asset impairment charge. In 2012, we recorded an asset impairment charge of $19.0 million associated with the long-lived assets at our 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 for discussion of the Pontiki mining complex.

Interest expense. Interest expense, net of capitalized interest, decreased to $27.0 million in 2013 from $28.7 million in 2012. The decrease of $1.7 million was principally attributable to reduced interest expense resulting from our August 2013 principal repayment of $18.0 million on our original senior notes issued in 1999, reduced interest expense resulting from lower rates and fees under our term loan and revolving credit facility entered into in May 2012, higher capitalized interest on our equity investment in White Oak in 2013 and $1.1 million of deferred debt issuance costs related to the early termination of the $300 million term loan in 2012. These decreases were partially offset by increased borrowings under our revolving credit facilities in 2013. The term loan and revolving credit facility are discussed in more detail below under Debt Obligations.

Equity in loss of affiliates, net. Equity in loss of affiliates, net includes our share of the results of operations of our equity investments in White Oak and MAC. Equity in loss of affiliates, net was $24.4 million in 2013 compared to $14.7 million in 2012, which was primarily attributable to losses allocated to us due to our equity investment in White Oak. For more information regarding White Oak, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

Transportation revenues and expenses. Transportation revenues and expenses each increased to $32.6 million in 2013 from $22.0 million in 2012. The increase of $10.6 million was attributable to an increase in average transportation rates in 2013 primarily related to new export sales from our Warrior mine, as well as increased tonnage in 2013 for which we arranged the transportation at certain other mines. The cost of transportation services are passed through to our customers. Consequently, we do not realize any gain or loss on transportation revenues.

Income tax (expense) benefit. Income tax expense was $1.4 million in 2013 compared to income tax benefit of $1.1 million in 2012. Income taxes are primarily due to the operations of Matrix Design. The income tax expense in 2013 was due to a valuation allowance of ASI s deferred tax assets, offset by an income tax benefit due to a net operating loss carry-forward related to Matrix Design from prior years, as well as research and development tax credits earned by Matrix Design.

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Segment Information. Our 2013 Segment Adjusted EBITDA increased 13.8% to $749.6 million from 2012 Segment Adjusted EBITDA of $658.8 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows (in thousands):

	Year Ended December 31,					
	2013		2012		Increase (Decrease)	
Segment Adjusted EBITDA						
Illinois Basin	$	657,404	$	593,054	$ 64,350	10.9%
Appalachia (4)		105,123		73,553	31,570	42.9%
White Oak		(25,229)		(13,987)	(11,242)	(80.4)%
Other and Corporate (4)		12,278		6,214	6,064	97.6%
Elimination		-		-	-	-
Total Segment Adjusted EBITDA (2)	$	749,576	$	658,834	$ 90,742	13.8%
Tons sold						
Illinois Basin		30,640		28,294	2,346	8.3%
Appalachia (4)		7,493		6,006	1,487	24.8%
White Oak		-		-	-	-
Other and Corporate (4)		775		870	(95)	(10.9)%
Elimination (4)		(73)		-	(73)	(1)
Total tons sold		38,835		35,170	3,665	10.4%
Coal sales						
Illinois Basin	$	1,605,232	$	1,485,640	$ 119,592	8.0%
Appalachia (4)		476,736		425,227	51,509	12.1%
White Oak		-		-	-	-
Other and Corporate (4)		60,073		68,570	(8,497)	(12.4)%
Elimination (4)		(4,592)		-	(4,592)	(1)
Total coal sales	$	2,137,449	$	1,979,437	$ 158,012	8.0%
Other sales and operating revenues						
Illinois Basin	$	3,858	$	2,183	$ 1,675	76.7%
Appalachia (4)		4,310		9,886	(5,576)	(56.4)%
White Oak		2,194		-	2,194	(1)
Other and Corporate (4)		38,199		37,289	910	2.4%
Elimination		(13,091)		(16,528)	3,437	20.8%
Total other sales and operating revenues	$	35,470	$	32,830	$ 2,640	8.0%
Segment Adjusted EBITDA Expense						
Illinois Basin	$	951,686	$	894,769	$ 56,917	6.4%
Appalachia (4)		375,923		361,560	14,363	4.0%
White Oak		2,112		(1,347)	3,459	(1)
Other and Corporate (4)		86,864		100,329	(13,465)	(13.4)%
Elimination (4)		(17,683)		(16,528)	(1,155)	(7.0)%
Total Segment Adjusted EBITDA Expense (3)	$	1,398,902	$	1,338,783	$ 60,119	4.5%

(1) Percentage change was greater than or equal to 100%.

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(2) Segment Adjusted EBITDA (a non-GAAP financial measure) is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization, general and administration expenses and asset impairment charge. Segment Adjusted EBITDA is a key component of consolidated EBITDA, which is used as a supplemental financial measure by management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on investment compared to those of other companies in the coal energy sector, without regard to financing or capital structures; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

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

	Year Ended December 31,	
	2013	**2012**
Segment Adjusted EBITDA	$ 749,576	$ 658,834
General and administrative	(63,697)	(58,737)
Depreciation, depletion and amortization	(264,911)	(218,122)
Asset impairment charge	-	(19,031)
Interest expense, net	(26,082)	(28,455)
Income tax (expense) benefit	(1,396)	1,082
Net income	$ 393,490	$ 335,571

(3) Segment Adjusted EBITDA Expense (a non-GAAP financial measure) includes operating expenses, outside coal purchases and other income. Transportation expenses are excluded as these expenses are passed through to our customers and, consequently, we do not realize any gain or loss on transportation revenues. Segment Adjusted EBITDA Expense is used as a supplemental financial measure by our management to assess the operating performance of our segments. In our evaluation of EBITDA, which is discussed above under *How We Evaluate Our Performance*, Segment Adjusted EBITDA Expense is a key component of Segment Adjusted EBITDA in addition to coal sales and other sales and operating revenues. The exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA Expense allows management to focus solely on the evaluation of segment operating performance as it primarily relates to our operating expenses. Outside coal purchases are included in Segment Adjusted EBITDA Expense because tons sold and coal sales include sales from outside coal purchases.

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

	Year Ended December 31,	
	2013	2012
Segment Adjusted EBITDA Expense	$ 1,398,902	$ 1,338,783
Outside coal purchases	(2,030)	(38,607)
Other income	1,891	3,115
Operating expense (excluding depreciation, depletion and amortization)	$ 1,398,763	$ 1,303,291

(4) In 2014, we realigned our segment presentation. The Appalachia segment is now comprised of the MC Mining, Mettiki and Tunnel Ridge mines. Results for the Pontiki mine, which ceased operations in November 2013, are now reflected in the Other and Corporate segment. Reclassifications of the 2013 and 2012 segment information have been made to the Appalachia and Other and Corporate segments, as well as eliminations above to conform to the 2014 presentation.

Illinois Basin Segment Adjusted EBITDA increased 10.9% to $657.4 million in 2013 from $593.1 million in 2012. The increase of $64.3 million was primarily attributable to increased tons sold, which rose 8.3% to 30.6 million tons sold in 2013, partially offset by a lower average coal sales price of $52.39 per ton in 2013 compared to $52.51 per ton in 2012 due to lower contract pricing particularly at our Gibson North mine. Coal sales increased 8.0% to $1.6 billion in 2013 compared to $1.5 billion in 2012. The increase of $119.6 million primarily reflects the increased tons produced and sold from improved recoveries and geologic conditions at our River View, Gibson North and Pattiki mines discussed above, and the benefit of increased production at the Onton mine acquired in April 2012. Segment Adjusted EBITDA Expense in 2013 increased 6.4% to $951.7 million from $894.8 million in 2012 due to the sales and production increases noted above. Although Segment Adjusted EBITDA Expense increased in 2013, Segment Adjusted EBITDA Expense per ton decreased $0.56 per ton sold to $31.06 from $31.62 per ton sold, primarily as a result of increased coal production, as well as certain other cost decreases discussed above under Operating expenses and outside coal purchases , partially offset by additional expenses and asset write-offs associated with the temporary halt in production from late July to mid-August 2013 at the Onton mine due to adverse geological conditions.

Appalachia Segment Adjusted EBITDA increased 42.9% to $105.1 million for 2013 compared to $73.6 million for 2012. The increase of $31.5 million was primarily attributable to increased tons sold, which rose 24.8% to 7.5 million tons sold, partially offset by lower average coal sales prices of $63.62 per ton sold during 2013 compared to $70.80 per ton sold for 2012 resulting from decreased sales into the metallurgical coal export markets. The start-up of longwall production at Tunnel Ridge was the primary reason for a 4.0% increase in Segment Adjusted EBITDA Expense to $375.9 million in 2013 from $361.6 million in 2012. Although Segment Adjusted EBITDA Expense increased, Segment Adjusted EBITDA Expense per ton decreased 16.7% to $50.17 per ton in 2013 from $60.20 per ton in 2012, primarily due to the lower cost per ton from longwall production at Tunnel Ridge. Segment Adjusted EBITDA Expense per ton in 2013 also benefited from lower costs at our Mettiki complex due to reduced contract mining and coal processing expenses, as well as lower outside coal purchases, all resulting primarily from reduced coal sales into the metallurgical coal export markets, partially offset by higher medical-related benefit costs at Mettiki.

White Oak Segment Adjusted EBITDA was $(25.2) million and $(14.0) million in 2013 and 2012, respectively, primarily attributable to losses allocated to us due to our equity interest in White Oak. Our investment in White Oak began in September 2011. For more information on White Oak, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

Other and Corporate   Segment Adjusted EBITDA decreased $5.3 million in 2013 from 2012. The decrease was primarily due to lower coal brokerage sales. Segment Adjusted EBITDA Expense decreased 24.1% to $40.2 million for 2013, primarily as a result of lower outside coal purchases related to reduced coal brokerage activity, offset in part by increased component expenses related to Matrix Group safety equipment sales.

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Pontiki Mine Asset Impairment Charge

Pontiki s mining complex in Martin County, Kentucky was idled from August 29, 2012 to November 25, 2012 following an MSHA closure order. This idling together with ongoing market uncertainty and the likelihood of future cost increases arising from stringent regulatory oversight placed the long-term viability of Pontiki at significant risk. As a result of these events, we recorded an asset impairment charge of $19.0 million during the quarter ended September 30, 2012 to reduce the carrying value of the asset group representing the Pontiki mining complex (Pontiki Assets) to an estimated fair value of $16.1 million, which was determined using the market and cost valuation techniques and represents a Level 3 fair value measurement. Although the Pontiki mining complex resumed production operations, we subsequently ceased operations at the Pontiki mining complex in late November 2013. Many of Pontiki s employees and some of its equipment were migrated to our MC Mining and other operations. No additional impairment was required related to the closure of the mine in 2013. We sold most of the remaining assets at the Pontiki mining complex in May 2014.

Ongoing Acquisition Activities

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

Liquidity and Capital Resources

Liquidity

We have historically satisfied our working capital requirements and funded our capital expenditures, equity investments and debt service obligations from cash generated from operations, cash provided by the issuance of debt or equity and borrowings under credit facilities. We believe that existing cash balances, future cash flows from operations, borrowings under credit facilities, and cash provided from the issuance of debt or equity will be sufficient to meet our working capital requirements, capital expenditures and equity investments, debt payments, commitments and distribution payments. Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance and access to and cost of financing sources, which will be affected by prevailing economic conditions generally and in the coal industry specifically, which are beyond our control. Based on our recent operating results, current cash position, anticipated future cash flows and sources of financing that we expect to have available, we do not anticipate any significant liquidity constraints in the foreseeable future. However, to the extent operating cash flow or access to and cost of financing sources are materially different than expected, future liquidity may be adversely affected. Please see Item 1A. Risk Factors.

On September 22, 2011 (the Transaction Date), we entered into a series of transactions with White Oak and related entities to support development of a longwall mining operation. The initial longwall system commenced operation in late October 2014. At December 31, 2014, we had funded $390.0 million related to these transactions and, inclusive of this funding, we expect to fund to White Oak a total of approximately $395.5 million to $415.5 million from the Transaction Date through December 31, 2015. Equity investments of $39.8 million and $45.9 million were contributed by another White Oak owner in 2014 and 2013, respectively. On the Transaction Date, we also entered into a coal handling and preparation agreement, pursuant to which we constructed and are operating a preparation plant and other surface facilities.

We plan to utilize existing cash balances, future cash flows from operations, borrowings under credit and securitization facilities and cash provided from the issuance of debt or equity to fund our commitments to the White Oak project. For more information on the White Oak transactions, please read Part II. Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

On the Cavalier Formation Date, Cavalier Minerals purchased equity interests in AllDale Minerals, an entity created to purchase oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. Cavalier Minerals initial investment funding to AllDale Minerals at the Cavalier Formation Date was $7.4 million and it has funded an additional $4.2 million between the Cavalier Formation Date and December 31, 2014. Cavalier Minerals has a remaining commitment to AllDale Minerals of $37.4 million at December 31, 2014, which it expects to fund over the next two to four years. Alliance Minerals committed funding of $48.0 million to Cavalier Minerals, of which $11.5 million was funded as of December 31, 2014 and the balance we expect to fund over the same period. Bluegrass Minerals Management, LLC (Bluegrass Minerals) also provides funding to Cavalier Minerals. We plan to utilize existing cash balances, future cash flows from operations, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity to fund Alliance Minerals commitments to Cavalier Minerals, which in turn principally uses this funding to fund its commitments to AllDale Minerals. For more information on these transactions, please read Part II. Item 8. Financial Statements and Supplementary Data Note 11. Noncontrolling Interest and Note 12. Equity Investments of this Annual Report on Form 10-K.

On December 31, 2014 (the Initial Closing Date), we entered into asset purchase agreements with Patriot regarding certain assets relating to two of Patriot s western Kentucky mining operations, including certain coal sales agreements, unassigned coal reserves and underground mining equipment and infrastructure located in Union and Henderson Counties, Kentucky. On the Initial Closing Date, our subsidiary, Alliance Coal acquired the rights to certain coal supply agreements from an affiliate of Patriot. On February 3, 2015 (the Subsequent Closing Date), Alliance Coal and Alliance Resource Properties acquired from Patriot an estimated 84.1 million tons of proven and probable high-sulfur coal reserves in western Kentucky (substantially all of which was leased by Patriot), and substantially all of Dodge Hill mining complex s assets related to its former coal mining operation in western Kentucky, which principally included underground mining equipment and an estimated 43.2 million tons of non-reserve coal deposits (substantially all of which was leased by Dodge Hill). Our purchase price of $19.2 million and $20.5 million paid on the Initial Closing Date and the Subsequent Closing Date, respectively, was financed using existing cash on hand. In addition, we assumed reclamation liabilities totaling $2.5 million. For more information on these transactions, please read Part II. Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K.

Cash Flows

Cash provided by operating activities was $739.2 million in 2014 compared to $704.7 million in 2013. The increase in cash provided by operating activities was primarily due to higher net income and an increase in accounts payable during 2014 as compared to a decrease during 2013, offset partially by an increase in trade receivables and coal inventories during 2014 compared to 2013.

Net cash used in investing activities was $441.2 million in 2014 compared to $426.0 million in 2013. The increase in cash used for investing activities was primarily attributable to the acquisition of coal supply agreements from Patriot, an increase in the funding of the White Oak equity investment and initial funding of the AllDale Minerals equity investment in 2014, partially offset by lower capital expenditures for mine infrastructure and equipment at various mines, particularly at our Gibson South and Tunnel Ridge mines, and a decrease in the acquisition and funding for development of coal reserves in 2014. For information regarding the acquisition of coal supply agreements from Patriot, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K.

Net cash used in financing activities was $367.0 million in 2014 compared to $213.3 million in 2013. The increase in cash used in financing activities was primarily attributable to increased distributions paid to partners in 2014, net payments under our revolving credit facilities and payments under our term loan in 2014, partially offset by borrowings under our new accounts receivable securitization facility. For information regarding the accounts receivable securitization facility, please read Item 8. Financial Statements and Supplementary Data Note 7. Long-Term Debt of this Annual Report on Form 10-K.

We have various commitments primarily related to long-term debt, including capital leases, operating lease commitments related to buildings and equipment, obligations for estimated future asset retirement obligations costs, workers compensation and pneumoconiosis, capital projects and pension funding. We expect to fund these commitments with existing cash balances, future cash flows from operations, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity.

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The following table provides details regarding our contractual cash obligations as of December 31, 2014 (in thousands):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt	$ 821,250	$ 230,000	$ 446,250	$ 145,000	$ -
Future interest obligations(1)	53,688	22,589	26,335	4,764	-
Operating leases	4,731	1,656	2,425	650	-
Capital leases(2)	21,651	2,054	3,915	3,748	11,934
Purchase obligations for capital projects	50,800	50,800	-	-	-
Reclamation obligations(3)	181,893	2,055	4,041	2,662	173,135
Workers compensation and pneumoconiosis benefit(3)	182,423	2,232	7,954	6,774	165,463
	$ 1,316,436	$ 311,386	$ 490,920	$ 163,598	$ 350,532

(1) Interest on variable-rate, long-term debt was calculated using rates elected by us at December 31, 2014 for the remaining term of outstanding borrowings.

(2) Includes amounts classified as interest and maintenance cost.

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

We expect to contribute $3.1 million to the defined benefit pension plan (Pension Plan) during 2015.

In addition to the above described capital expenditures related to our operating activities, we currently anticipate funding to White Oak during 2015 of approximately $12.1 million for reserve acquisitions and additional equity investment related to our participation in the White Oak Mine No. 1. We also currently anticipate funding to AllDale Minerals during the next two to four years approximately $37.4 million for the acquisition of oil and gas mineral interests in various geographic locations within producing basins in the continental U.S.

Off-Balance Sheet Arrangements

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

We use a combination of surety bonds and letters of credit to secure our financial obligations for reclamation, workers compensation and other obligations as follows as of December 31, 2014 (in millions):

	Reclamation Obligation	Workers Compensation Obligation	Other	Total
Surety bonds	$ 142.3	$ 56.6	$ 8.9	$ 207.8
Letters of credit	-	22.7	13.4	36.1

Our continuing involvement in our unconsolidated affiliate, White Oak, will primarily consist of our support of their longwall mine, which commenced initial longwall operation in late October 2014. We have committed to and have funded reserve acquisitions, reserve development, the construction of surface facilities, surface facility financing and the purchase of additional equity in White Oak. In addition, we incurred allocated losses related to our equity investment in White Oak of $16.6 million for the year ended December 31, 2014 and expect to incur further allocated losses on our equity investment in White Oak over the next twelve months as White Oak continues to advance its operations. For more information on the White Oak transactions, please read Part II. Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

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Our involvement in our unconsolidated affiliate, AllDale Minerals, consists of our support of the acquisition of oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. We incurred allocated losses related to Cavalier Minerals equity investment in AllDale Minerals of $0.4 million for the year ended December 31, 2014 and expect to incur allocated losses on an equity investment in AllDale Minerals over the next twelve months as AllDale Minerals begins its initial operations. For more information on our involvement with AllDale Minerals, please read Part II. Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

Capital Expenditures

Capital expenditures decreased to $307.4 million in 2014 compared to $329.2 million in 2013. See our discussion of Cash Flows above concerning this decrease in capital expenditures.

We currently project average estimated annual maintenance capital expenditures over the next five years of approximately $5.55 per ton produced. Our anticipated total capital expenditures, including maintenance capital expenditures, for 2015 are estimated in a range of $300.0 to $330.0 million. Management anticipates funding 2015 capital requirements with our December 31, 2014 cash and cash equivalents of $24.6 million, future cash flows from operations, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity, as discussed below. We will continue to have significant capital requirements over the long-term, which may require us to incur debt or seek additional equity capital. The availability and cost of additional capital will depend upon prevailing market conditions, the market price of our common units and several other factors over which we have limited control, as well as our financial condition and results of operations.

Insurance

Effective October 1, 2014, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market at a reduced cost. The maximum limit in the commercial property program is $100.0 million per occurrence, excluding a $1.5 million deductible for property damage, a 90 or 120 day waiting period for underground business interruption depending on the mining complex and an additional $10.0 million overall aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

Debt Obligations

Credit Facility and Senior Notes

Credit Facility. On May 23, 2012, our Intermediate Partnership entered into a credit agreement (the Credit Agreement) with various financial institutions for a revolving credit facility (the Revolving Credit Facility) of $700.0 million and a term loan (the Term Loan) in the aggregate principal amount of $250.0 million (collectively, the Revolving Credit Facility and Term Loan are referred to as the Credit Facility). Borrowings under the Credit Agreement bear interest at a Base Rate or Eurodollar Rate, at our election, plus an applicable margin that fluctuates depending upon the ratio of Consolidated Debt to Consolidated Cash Flow (each as defined in the Credit Agreement). We have elected a Eurodollar Rate, which, with applicable margin, was 1.57% on borrowings outstanding as of December 31, 2014. The Credit Facility matures May 23, 2017, at which time all amounts then outstanding are required to be repaid. Interest is payable quarterly, with principal of the Term Loan due as follows: for each quarter commencing June 30, 2014 and ending March 31, 2016, quarterly principal payments in an amount per quarter equal to 2.50% of the aggregate amount of the Term Loan advances outstanding; for each quarter beginning June 30, 2016 through December 31, 2016, 20% of the aggregate amount of the Term Loan advances outstanding; and the remaining balance of the Term Loan advances at maturity. In June 2014, we began making quarterly principal payments on the Term Loan, leaving a balance of $231.3 million at December 31, 2014. We have the option to prepay the Term Loan at any time in whole or in part subject to terms and conditions described in the Credit Agreement. Upon a change of control (as defined in the Credit Agreement), the unpaid principal amount of the Credit Facility, all interest thereon and all other amounts payable under the Credit Agreement would become due and payable.

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At December 31, 2014, we had borrowings of $140.0 million and $5.4 million of letters of credit outstanding with $554.6 million available for borrowing under the Revolving Credit Facility. We utilize the Revolving Credit Facility, as appropriate, for working capital requirements, capital expenditures, debt payments and distribution payments. We incur an annual commitment fee of 0.20% on the undrawn portion of the Revolving Credit Facility.

We incurred debt issuance costs of approximately $4.3 million in 2012 associated with the Credit Agreement, which have been deferred and are being amortized as a component of interest expense over the duration of the Credit Agreement. We also expensed $1.1 million in 2012 of previously deferred debt issuance cost associated with our previous $300 million term loan.

Series A Senior Notes. On June 26, 2008, our Intermediate Partnership entered into a Note Purchase Agreement (the 2008 Note Purchase Agreement) with a group of institutional investors in a private placement offering. We issued $205.0 million of Series A senior notes, which bear interest at 6.28% and mature on June 26, 2015 with interest payable semi-annually.

Series B Senior Notes. On June 26, 2008, we issued under the 2008 Note Purchase Agreement $145.0 million of Series B senior notes (together with the Series A senior notes, the 2008 Senior Notes), which bear interest at 6.72% and mature on June 26, 2018 with interest payable semi-annually.

The 2008 Senior Notes and the Credit Facility described above (collectively, ARLP Debt Arrangements) are guaranteed by all of the material direct and indirect subsidiaries of our Intermediate Partnership. The ARLP Debt Arrangements contain various covenants affecting our Intermediate Partnership and its subsidiaries restricting, among other things, the amount of distributions by our Intermediate Partnership, incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates, in each case subject to various exceptions. The ARLP Debt Arrangements also require the Intermediate Partnership to remain in control of a certain amount of mineable coal reserves relative to its annual production. In addition, the ARLP Debt Arrangements require our Intermediate Partnership to maintain (a) debt to cash flow ratio of not more than 3.0 to 1.0 and (b) cash flow to interest expense ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt to cash flow ratio and cash flow to interest expense ratio were 1.01 to 1.0 and 24.0 to 1.0, respectively, for the trailing twelve months ended December 31, 2014. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2014.

Accounts Receivable Securitization. On December 5, 2014, certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership entered into a $100.0 million accounts receivable securitization facility (Securitization Facility) providing additional liquidity and funding. Under the Securitization Facility, certain subsidiaries sell trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to $100.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a Eurodollar Rate. The Securitization Facility has an initial term of 364 days, however we have the contractual ability and the intent to extend the term for an additional 364 days. At December 31, 2014, we had $100.0 million outstanding under the Securitization Facility. Debt issuance costs were immaterial for the transaction.

Other. In addition to the letters of credit available under the Credit Facility discussed above, we also have agreements with two banks to provide additional letters of credit in an aggregate amount of $31.1 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers compensation benefits. At December 31, 2014, we had $30.7 million in letters of credit outstanding under agreements with these two banks.

Critical Accounting Policies and Estimates

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

Revenue Recognition

Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer s analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, we estimate the amount of the quality adjustment and adjust the estimate to actual when the information is provided by the customer. Historically such adjustments have not been material.

Non-coal sales revenues primarily consist of transloading fees, administrative service revenues from our affiliates, mine safety services and products, royalties and throughput fees earned from White Oak and other handling and service fees. These non-coal sales revenues are recognized when the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; the seller s price to the buyer is fixed or determinable; and collectability is reasonably assured.

Coal Reserve Values

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. Certain account classifications within our financial statements such as depreciation, depletion, and amortization, impairment charges and certain liability calculations such as asset retirement obligations may depend upon estimates of coal reserve quantities and values. Accordingly, when actual coal reserve quantities and values vary significantly from estimates, certain accounting estimates and amounts within our consolidated financial statements may be materially impacted. Coal reserve values are reviewed annually, at a minimum, for consideration in our consolidated financial statements.

Workers Compensation and Pneumoconiosis (Black Lung) Benefits

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. We generally provide for these claims through self-insurance programs. Workers compensation laws also compensate survivors of workers who suffer employment related deaths. The liability for traumatic injury claims is our estimate of the present value of current workers compensation benefits, based on our actuary estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates. We had accrued liabilities of $57.6 million and $62.9 million for these costs at December 31, 2014 and 2013, respectively. A one-percentage-point reduction in the discount rate would have increased the liability and operating expense by approximately $5.1 million at December 31, 2014.

Coal mining companies are subject to CMHSA, as amended, and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker s pneumoconiosis, or black lung. We provide for these claims through self-insurance programs. Our black lung benefits liability is calculated using the service cost method based on the actuarial present value of the estimated black lung obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and discount rates. We had accrued liabilities of $56.4 million and $49.6 million for these benefits at December 31, 2014 and 2013, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2014 by approximately $1.1 million. Under the service cost method used to estimate our black lung benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions, such as the discount rate, are amortized over the remaining service period of active miners.

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

Defined Benefit Plan

Eligible employees at certain of our mining operations participate in a Pension Plan that we sponsor. The benefit formula for the Pension Plan is a fixed dollar unit based on years of service. The calculation of our net periodic benefit cost (pension expense) and benefit obligation (pension liability) associated with our Pension Plan requires the use of a number of assumptions. Changes in these assumptions can result in materially different pension expense and pension liability amounts. In addition, actual experiences can differ materially from the assumptions. Significant assumptions used in calculating pension expense and pension liability are as follows:

- Our expected long-term rate of return assumption is based on broad equity and bond indices, the investment goals and objectives, the target investment allocation and on the long-term historical rates of return for each asset class. Our expected long-term rate of return used to determine our pension liability was 8.00% at December 31, 2014 and 2013. Our expected long-term rate of return used to determine our pension expense was 8.00% for the years ended December 31, 2014 and 2013. The expected long-term rate of return used to determine our pension liability is based on an asset allocation assumption of 70.0% invested in domestic equity securities with an expected long-term rate of return of 9.9%, 10.0% invested in international equities with an expected long-term rate of return of 5.6% and 20.0% invested in fixed income securities with an expected long-term rate of return of 5.7%. Our expected long-term rate of return is based on a 20-year-average annual total return for each investment group. Additionally, we base our determination of pension expense on a smoothed market-related valuation of assets equal to the fair value of assets, which immediately recognizes all investment gains or losses. The actual return on plan assets was 5.4% and 22.7% for the years ended December 31, 2014 and 2013, respectively. Lowering the expected long-term rate of return assumption by 1.0% (from 8.00% to 7.00%) at December 31, 2013 would have increased our pension expense for the year ended December 31, 2014 by approximately $0.5 million; and

- Our weighted-average discount rate used to determine our pension liability was 3.92% and 4.89% at December 31, 2014 and 2013, respectively. Our weighted-average discount rate used to determine our pension expense was 4.89% and 3.99% at December 31, 2014 and 2013, respectively. The discount rate that we utilize for determining our future pension obligation is based on a review of currently available high-quality fixed-income investments that receive one of the two highest ratings given by a recognized rating agency. We have historically used the average monthly yield for December of an A-rated utility bond index as the primary benchmark for establishing the discount rate. Lowering the discount rate assumption by 0.5% (from 4.89% to 4.39%) at December 31, 2013 would have increased our pension expense for the year ended December 31, 2014 by approximately $0.1 million.

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Long-Lived Assets

We review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Long-lived assets and certain intangibles are not reviewed for impairment unless an impairment indicator is noted. Several examples of impairment indicators include:

- A significant decrease in the market price of a long-lived asset;
- A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset; or
- A significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition.

The above factors are not all inclusive, and management must continually evaluate whether other factors are present that would indicate a long-lived asset may be impaired. If there is an indication that carrying amount of an asset may not be recovered, the asset is monitored by management where changes to significant assumptions are reviewed. Individual assets are grouped for impairment review purposes based on the lowest level for which there is identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a by-mine basis. The amount of impairment is measured by the difference between the carrying value and the fair value of the asset. The fair value of impaired assets is typically determined based on various factors, including the present values of expected future cash flows, the marketability of coal properties and the estimated fair value of assets that could be sold or used at other operations. We recorded an asset impairment charge of $19.0 million in 2012 (see Item 8. Financial Statements and Supplementary Data Note 4. Asset Impairment Charge of this Annual Report on Form 10-K). No impairment charges were recorded in 2014 and 2013.

Equity Method Investments

We review the carrying value of equity method investments whenever events or changes in circumstances indicate that the carrying amount may be impaired. Equity method investments are not reviewed for impairment unless an impairment indicator is noted. Several examples of impairment indicators include:

- A series of operating losses of an investee or other factors indicating an other than temporary decrease in value;
- An indication of the absence of the ability to recover the carrying amount of the investment; or
- An indication of the absence of the investee to sustain an earnings capacity to justify the carrying amount.

The above factors are not all inclusive, and management must continually evaluate whether other factors are present that would indicate an equity method investment may be impaired. The amount of impairment is measured by the difference between the carrying value and the fair value of an equity method investment. The fair value of impaired equity method investments are typically determined based on various factors, including, but not limited to, the present values of expected future cash flows.

Mine Development Costs

Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized on a units of production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Our estimate of when construction of the mine for economic extraction is substantially complete is based upon a number of factors, such as expectations regarding the economic recoverability of reserves, the type of mine under development, and completion of certain mine requirements, such as ventilation. Coal extracted during the development phase is incidental to the mine s production capacity and is not considered to shift the mine into the production phase. At December 31, 2014 and 2013, capitalized mine development costs were $7.0 million and $33.1 million, respectively, representing the carrying value of development costs attributable to properties where we have not reached the production stage of mining operations or leasing to third parties, and therefore, the mine development costs are not currently being amortized. We believe that the carrying value of these development costs will be recovered.

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Asset Retirement Obligations

SMCRA and similar state statutes require that mined property be restored in accordance with specified standards and an approved reclamation plan. A liability is recorded for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support acreage at surface mines. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accrued liabilities of $93.1 million and $82.9 million for these costs are recorded at December 31, 2014 and 2013, respectively. The liability for asset retirement and closing procedures is sensitive to changes in cost estimates and estimated mine lives.

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

On at least an annual basis, we review our entire asset retirement obligation liability and make necessary adjustments for permit changes as granted by state authorities, changes in the timing of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Adjustments to the liability resulted in an increase of $8.6 million and a decrease of $2.7 million for the years ended December 31, 2014 and 2013, respectively. The adjustments to the liability for the year ended December 31, 2014 were attributable to increased refuse site reclamation disturbances primarily at our Onton, Gibson South, Tunnel Ridge, Dotiki and River View operations and the acquisition of additional property with certain existing reclamation liabilities, offset in part by the sale of property associated with the Pontiki mine, as well as the net impact of overall general changes in inflation and discount rates, current estimates of the costs and scope of remaining reclamation work, reclamation work completed and fluctuations in other projected mine life estimates.

While the precise amount of these future costs cannot be determined with certainty, we have estimated the costs and timing of future asset retirement obligations escalated for inflation, then discounted and recorded at the present value of those estimates. Discounting resulted in reducing the accrual for asset retirement obligations by $88.8 million and $76.5 million at December 31, 2014 and 2013. We estimate that the aggregate undiscounted cost of final mine closure is approximately $181.9 million at December 31, 2014. If our assumptions differ from actual experiences, or if changes in the regulatory environment occur, our actual cash expenditures and costs that we incur could be materially different than currently estimated.

Contingencies

We are currently involved in certain legal proceedings. Our estimates of the probable costs and probability of resolution of these claims are based upon a number of assumptions, which we have developed in consultation with legal counsel involved in the defense of these matters and based upon an analysis of potential results, assuming a combination of litigation and settlement strategies. Based on known facts and circumstances, we believe the ultimate outcome of these outstanding lawsuits, claims and regulatory proceedings will not have a material adverse effect on our financial condition, results of operations or liquidity. However, if the results of these matters were different from management s current opinion and in amounts greater than our accruals, then they could have a material adverse effect.

Universal Shelf

In February 2012, we filed with the SEC a universal shelf registration statement allowing us to issue from time to time an indeterminate amount of debt or equity securities (2012 Registration Statement). At February 27, 2015, we had not utilized any amounts available under the 2012 Registration Statement. We intend to file with the SEC a new universal shelf registration statement following the expiration of the 2012 Registration Statement.

Related Party Transactions

The Board of Directors and the conflicts committee of the MGP Board of Directors (Conflicts Committee) review our related-party transactions that involve a potential conflict of interest between a general partner and ARLP or its subsidiaries or another partner to determine that such transactions reflect market-clearing terms and conditions

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customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to us and our limited partners.

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into Administrative Services Agreement with our managing general partner, our Intermediate Partnership, AHGP and its general partner AGP, and ARH II, the indirect parent of SGP. 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 to our managing general partner, AHGP, AGP, ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these affiliates as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under the Administrative Services Agreement of $0.4 million during each of the years ended December 31, 2014, 2013 and 2012 from AHGP and $0.1 million during each of the years ended December 31, 2014, 2013 and 2012 from ARH II, respectively.

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, director fees and expenses, management s salaries and related benefits (including incentive compensation), and accounting, budgeting, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $0.8 million, $0.8 million and $1.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Managing General Partner Contributions

During December 2014, 2013 and 2012, an affiliated entity controlled by Mr. Craft contributed $1.5 million, $2.2 million and $2.0 million, respectively, to AHGP for the purpose of funding certain of our general and administrative expenses. Upon AHGP s receipt of each contribution, it contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made special allocations to our managing general partner of certain general and administrative expenses equal to its contributions.

White Oak Transactions

On September 22, 2011, we entered into a series of transactions with White Oak and related entities to support development of a longwall mining operation. The initial longwall system commenced operation in late October 2014. The transactions feature several components, including an equity investment containing certain distribution and liquidation preferences, the acquisition and lease-back of certain reserves and surface rights, a coal handling and services agreement and a loan for surface facilities. The transactions are expected to generate equity distributions and have begun generating royalties and throughput revenues. For more information about the White Oak Transactions, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

In addition to the agreements discussed above, White Oak also has agreements with our subsidiaries for the purchase of various services and products, including for coal handling services provided by our Mt. Vernon transloading facility. For the years ended December 31, 2014, 2013 and 2012, we recorded revenues of $3.9 million, $2.4 million and $1.0 million, respectively, for services and products provided by Mt. Vernon and Matrix Design to White Oak, which are included in Other sales and operating revenues on our consolidated statements of income. For information on royalties and throughput revenues, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

SGP Land, LLC

On March 1, 2012, JC Air, LLC (JC Air), a wholly owned subsidiary of our special general partner, was acquired by and merged into our subsidiary, ASI. JC Air s sole assets were two airplanes, one of which was previously subject to

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a time-sharing agreement between SGP Land, LLC (SGP Land), a subsidiary of SGP, and us. In consideration for this merger, we paid SGP approximately $8.0 million cash at closing.

ASI has agreements with JC Land LLC (JC Land), an entity owned by Mr. Craft, SGP Land and Mr. Craft, providing for the use of ASI s aircraft. JC Land, SGP and Mr. Craft paid us $0.1 million for aircraft usage in each of the years ended December 31, 2014, 2013 and 2012, as a result of these agreements. In addition, Alliance Coal has an agreement with JC Land providing for the use of JC Land s aircraft by Alliance Coal. As a result of this agreement, we paid JC Land $0.2 million, $0.3 million and $0.1 million for aircraft usage in the years ended December 31, 2014, 2013 and 2012, respectively.

Effective August 1, 2013, Alliance Coal entered into an expense reimbursement agreement with JC Land regarding pilots hired by Alliance Coal to operate aircraft owned by ASI and JC Land. In accordance with the expense reimbursement agreement, JC Land reimburses Alliance Coal for a portion of the compensation expense for its pilots. JC Land paid us $0.2 million and $0.1 million for the years ended December 31, 2014 and 2013, respectively, pursuant to this agreement.

We reimbursed SGP Land $0.3 million for the year ended December 31, 2012, in accordance with the provisions of the replaced time-sharing agreement, which ended on March 1, 2012 upon the merger of JC Air into ASI, as discussed above.

In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty of $0.3 million until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $0.9 million, $0.3 million and $0.3 million for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014, all advanced minimum royalties paid under the lease have been recouped.

SGP

In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease with SGP. Under the terms of the lease, Tunnel Ridge has paid and will continue to pay an annual minimum royalty of $3.0 million until the earlier of January 1, 2033 or the exhaustion of the mineable and merchantable leased coal. Tunnel Ridge paid advance minimum royalties of $3.0 million during each of the years ended December 31, 2014, 2013 and 2012. As of December 31, 2014, $10.7 million of advance minimum royalties paid under the lease is available for recoupment and management expects that it will be recouped against future production.

Tunnel Ridge also controls surface land and other tangible assets under a separate lease agreement with SGP. Under the terms of the lease agreement, Tunnel Ridge has paid and will continue to pay SGP an annual lease payment of $0.2 million. The lease agreement had an initial term of four years, which may be extended to match the term of the coal lease. Lease expense was $0.2 million for each of the years ended December 31, 2014, 2013 and 2012.

We have a noncancelable lease arrangement for the Gibson North mine s coal preparation plant and ancillary facilities with SGP. The lease requires monthly payments of approximately $50,000 and extends through January 2017. Based on the lease arrangement, it is considered a capital lease. Lease payments for each of the years ended December 31, 2014, 2013 and 2012 were $0.6 million.

WKY CoalPlay

On November 17, 2014 (the CoalPlay Formation Date), SGP Land and two limited liability companies owned by irrevocable trusts established by our President and Chief Executive Officer (Craft Companies), entered into a limited liability company agreement to form WKY CoalPlay. WKY CoalPlay was formed, in part, to purchase and lease coal reserves. WKY CoalPlay is managed by an entity controlled by an officer of ARH who is also a director of ARH II, the indirect parent of SGP, an employee of SGP Land and a trustee of the irrevocable trusts owning the Craft Companies.

In December 2014, WKY CoalPlay acquired approximately 86.6 million tons of proven and probable high-sulfur coal reserves in western Kentucky and southern Indiana through its purchase of two indirect subsidiaries of CONSOL Energy Inc. for $57.2 million. WKY CoalPlay s acquired subsidiaries subsequently leased 72.3 million tons of the acquired reserves to us and, as partial consideration for entering the leases, conveyed the remaining 14.3 million tons of its acquired reserves to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a

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mine plan. The leases have initial terms ranging from 7 to 20 years and provide for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $6.2 million. All annual minimum royalty payments are recoupable against earned royalty payments. WKY CoalPlay also granted to us an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the leases. We paid WKY CoalPlay $6.2 million in January 2015 for the initial annual minimum royalty payment.

In December 2014, WKY CoalPlay acquired approximately 54.1 million tons of proven and probable high-sulfur coal reserves in western Kentucky through its purchase of a subsidiary of Midwest for $29.6 million. In conjunction with this acquisition, WKY CoalPlay s acquired subsidiary leased 22.6 million tons of the acquired reserves to us and, as partial consideration for entering the leases, conveyed the remaining 31.5 million tons of its acquired reserves to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a mine plan. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $2.5 million. All annual minimum royalty payments are recoupable against earned royalty payments. WKY CoalPlay also granted to us an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the lease. We paid WKY CoalPlay $2.5 million in January 2015 for the initial annual minimum royalty payment.

In February 2015, WKY CoalPlay acquired approximately 39.1 million tons of proven and probable high-sulfur owned coal reserves located in Henderson and Union Counties, Kentucky from Central States, a subsidiary of Patriot, for $25.0 million and in turn leased those reserves to us. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $2.1 million. All annual minimum royalty payments are recoupable against earned royalty payments. An option was also granted to us to acquire the leased reserves at any time during a three-year period beginning in February 2018 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the lease. We paid WKY CoalPlay $2.1 million in February 2015 for the initial annual minimum royalty payment.

Based on the guidance in Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810, we concluded that WKY CoalPlay is a variable interest entity (VIE) because exercise of the options noted above is not within the control of the equity holders and, if it occurs, could potentially limit the expected residual return to the owners of WKY CoalPlay. We do not have any economic or governance rights related to WKY CoalPlay and our options that provide us with a variable interest in WKY CoalPlay s reserve assets do not give us any rights that constitute power to direct the primary activities that most significantly impact WKY CoalPlay s economic performance. SGP Land has the sole ability to replace the manager of WKY CoalPlay at its discretion and therefore has power to direct the activities of WKY CoalPlay. Consequently, we concluded that SGP Land is the primary beneficiary of WKY CoalPlay.

Total future minimum royalties from 2015 through 2019 under agreements with SGP Land, SGP and WKY CoalPlay as discussed above are expected to be the following (in thousands):

Year Ending December 31,	
2015	$ 14,118
2016	13,857
2017	13,818
2018	13,818
2019	13,818

Cavalier Minerals

On November 10, 2014, Cavalier Minerals contributed $7.4 million in return for a limited partner interest in AllDale Minerals, an entity created to purchase oil and gas mineral interests in various geographical locations within producing basins in the continental U.S. Additional contributions totaling $4.2 million were made to AllDale Minerals prior to December 31, 2014 with the remaining commitment of $37.4 million expected to be paid over the next two to four years. At December 31, 2014, Cavalier Minerals   limited partner interest in AllDale Minerals was 71.7%. AllDale Minerals is managed and controlled by its general partner, AllDale Minerals Management, LLC (AllDale Minerals Management). AllDale Minerals Management is owned by four members, consisting of three parties unrelated to us or our affiliates and Bluegrass Minerals, which is owned by an officer of ARH. See Item 8. Financial Statements and Supplementary Data Note 11. Noncontrolling Interest and Note 12. Equity Investments for further information.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $228.5 million and $219.6 million at December 31, 2014 and 2013, respectively. These accruals were chiefly comprised of workers compensation benefits, black lung benefits, and costs associated with asset retirement obligations. These obligations are self-insured except for certain excess insurance coverage for workers compensation. The accruals of these items were based on estimates of future expenditures based on current legislation, related regulations and other developments. Thus, from time to time, our results of operations may be significantly affected by changes to these liabilities. Please see Item 8. Financial Statements and Supplementary Data Note 17. Asset Retirement Obligations and Note 18. Accrued Workers Compensation and Pneumoconiosis Benefits.

Inflation

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

New Accounting Standards

New Accounting Standards Issued and Not Yet Adopted

In April 2014, the FASB issued ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the requirements for reporting discontinued operations in ASC 205, Presentation of Financial Statements, by updating the criteria for determining which disposals can be presented as discontinued operations and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of discontinued operations. ASU 2014-08 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. We do not anticipate the adoption of ASU 2014-08 on January 1, 2015 will have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (ASU 2014-09). ASU 2014-09 is a new revenue recognition standard that provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the new standard is an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016 and shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. Early adoption is not permitted. We are currently evaluating the effect of adopting

ASU 2014-09.

In August 2014, the FASB issued ASU 2014-15, Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern (ASU 2014-15). ASU 2014-15 provides guidance on management s responsibility in evaluating whether there is substantial doubt about an entity s ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter with early adoption permitted. We do not anticipate the adoption of ASU 2014-15 will have a material impact on our consolidated financial statements.

Other Information

IRS Notice

On April 12, 2013, we received a Notice of Beginning of Administrative Proceeding from the IRS notifying us of an audit of the income tax return of Alliance Coal, the holding company for the operations of our Intermediate Partnership, for the tax year ending December 31, 2011. On February 11, 2015, the tax matters partner of Alliance Coal received

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notice from the IRS that it has completed its audit of Alliance Coal. The IRS is not proposing any adjustments to the tax return.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

We have significant long-term coal supply agreements as evidenced by approximately 85.7% of our sales tonnage, including approximately 85.0% of our medium- and high-sulfur coal sales tonnage, being sold under long-term contracts in 2014. Most of the long-term coal supply agreements are subject to price adjustment provisions, which periodically permit an increase or decrease in the contract price, typically to reflect changes in specified indices or changes in production costs resulting from regulatory changes, or both. For additional discussion of coal supply agreements, please see Item 1. Business Coal Marketing and Sales and Item 8. Financial Statements and Supplementary Data Note 21. Concentration of Credit Risk and Major Customers. As of February 13, 2015, our nominal commitment under long-term contracts was approximately 39.3 million tons in 2015, 28.9 million tons in 2016, 12.8 million tons in 2017 and 9.6 million tons in 2018. In 2014, the customer under one of our long-term coal supply agreements notified us that it would not accept any more coal shipments after April 15, 2015. Please read Item 3. Legal Proceedings.

We have exposure to price risk for supplies that are used directly or indirectly in the normal course of coal production such as steel, electricity and other supplies. We manage our risk for these items through strategic sourcing contracts for normal quantities required by our operations. We do not utilize any commodity price-hedges or other derivatives related to these risks.

Credit Risk

In 2014, approximately 95.6% of our sales tonnage was purchased by electric utilities. Therefore, our credit risk is primarily with domestic electric power generators. Our policy is to independently evaluate each customer s creditworthiness prior to entering into transactions and to constantly monitor outstanding accounts receivable against established credit limits. When deemed appropriate by our credit management department, we will take steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps may include obtaining letters of credit or cash collateral, requiring prepayments for shipments or establishing customer trust accounts held for our benefit in the event of a failure to pay.

Exchange Rate Risk

Almost all of our transactions are denominated in U.S. dollars, and as a result, we do not have material exposure to currency exchange-rate risks.

Interest Rate Risk

Borrowings under the Credit Facility and Securitization Facility are at variable rates and, as a result, we have interest rate exposure. Historically, our earnings have not been materially affected by changes in interest rates. We do not utilize any interest rate derivative instruments related to our outstanding debt. We had $140.0 million in borrowings under the Revolving Credit Facility, $231.3 million outstanding under the Term Loan and $100.0 million in borrowings under the Securitization Facility at December 31, 2014. A one percentage point increase in the interest rates related to the Credit Facility and Securitization Facility would result in an annualized increase in interest expense of $4.7 million, based on borrowing levels at December 31, 2014. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a decrease of approximately $5.9 million in the estimated fair value of these borrowings.

The table below provides information about our market sensitive financial instruments and constitutes a forward-looking statement. The fair values of long-term debt are estimated using discounted cash flow analyses, based upon our current incremental borrowing rates for similar types of borrowing arrangements as of December 31, 2014 and 2013.

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The carrying amounts and fair values of financial instruments are as follows (in thousands):

Expected Maturity Dates as of December 31, 2014	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value December 31, 2014
Fixed rate debt	$ 205,000	$ -	$ -	$ 145,000	$ -	$ -	$ 350,000	$ 364,221
Weighted-average interest rate	6.54%	6.72%	6.72%	6.72%	-	-		
Variable rate debt	$ 25,000	$ 256,250	$ 190,000	$ -	$ -	$ -	$ 471,250	$ 469,130
Weighted-average interest rate (1)	1.42%	1.41%	1.57%	-	-	-		

Expected Maturity Dates as of December 31, 2013	2014	2015	2016	2017	2018	Thereafter	Total	Fair Value December 31, 2013
Fixed rate debt	$ 18,000	$ 205,000	$ -	$ -	$ 145,000	$ -	$ 368,000	$ 390,028
Weighted-average interest rate	6.52%	6.54%	6.72%	6.72%	6.72%	-		
Variable rate debt	$ 18,750	$ 25,000	$ 156,250	$ 300,000	$ -	$ -	$ 500,000	$ 494,804
Weighted-average interest rate(1)	1.82%	1.82%	1.82%	1.82%	-	-		

(1) Interest rate on variable rate debt equal to the rate elected by us as of December 31, 2014 and 2013, held constant for the remaining term of the outstanding borrowing.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

The Board of Directors of Alliance Resource Management GP, LLC

and the Partners of Alliance Resource Partners, L.P.

We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and partners capital for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15(a)(2). These financial statements and schedule are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Alliance Resource Partners, L.P. and subsidiaries at December 31, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013) and our report dated February 27, 2015 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2015

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2014 AND 2013
(In thousands, except unit data)

ASSETS	**December 31, 2014**	**2013**
CURRENT ASSETS:		
Cash and cash equivalents	$ 24,601	$ 93,654
Trade receivables	184,187	153,662
Other receivables	1,025	776
Due from affiliates	7,221	1,964
Inventories	83,155	44,214
Advance royalties	9,416	11,454
Prepaid expenses and other assets	31,283	16,186
Total current assets	340,888	321,910
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	2,815,620	2,645,872
Less accumulated depreciation, depletion and amortization	(1,150,414)	(1,031,493)
Total property, plant and equipment, net	1,665,206	1,614,379
OTHER ASSETS:		
Advance royalties	15,895	18,813
Due from affiliate	11,047	11,560
Equity investments in affiliates	224,611	130,410
Other long-term assets	27,412	24,826
Total other assets	278,965	185,609
TOTAL ASSETS	$ 2,285,059	$ 2,121,898
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 85,843	$ 79,371
Due to affiliates	370	290
Accrued taxes other than income taxes	19,426	19,061
Accrued payroll and related expenses	57,656	47,105
Accrued interest	318	996
Workers compensation and pneumoconiosis benefits	8,868	9,065
Current capital lease obligations	1,305	1,288
Other current liabilities	17,109	18,625
Current maturities, long-term debt	230,000	36,750
Total current liabilities	420,895	212,551
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	591,250	831,250
Pneumoconiosis benefits	55,278	48,455
Accrued pension benefit	40,105	18,182
Workers compensation	49,797	54,949
Asset retirement obligations	91,085	80,807
Long-term capital lease obligations	15,624	17,135
Other liabilities	5,978	7,332
Total long-term liabilities	849,117	1,058,110
Total liabilities	1,270,012	1,270,661
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Alliance Resource Partners, L.P. (ARLP) Partners Capital:		
	1,310,517	1,128,519

Limited Partners - Common Unitholders 74,060,634 and 73,926,108 units outstanding, respectively				
General Partners deficit		(260,088)		(267,563)
Accumulated other comprehensive loss		(35,847)		(9,719)
Total ARLP Partners Capital		1,014,582		851,237
Noncontrolling interest		465		-
Total Partners Capital		1,015,047		851,237
TOTAL LIABILITIES AND PARTNERS CAPITAL	$	2,285,059	$	2,121,898

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2014	**2013**	**2012**
SALES AND OPERATING REVENUES:			
Coal sales	$ 2,208,611	$ 2,137,449	$ 1,979,437
Transportation revenues	26,021	32,642	22,034
Other sales and operating revenues	66,089	35,470	32,830
Total revenues	2,300,721	2,205,561	2,034,301
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	1,383,360	1,398,763	1,303,291
Transportation expenses	26,021	32,642	22,034
Outside coal purchases	14	2,030	38,607
General and administrative	72,552	63,697	58,737
Depreciation, depletion and amortization	274,566	264,911	218,122
Asset impairment charge	-	-	19,031
Total operating expenses	1,756,513	1,762,043	1,659,822
INCOME FROM OPERATIONS	544,208	443,518	374,479
Interest expense (net of interest capitalized of $833, $8,992 and $8,436, respectively)	(33,584)	(27,044)	(28,684)
Interest income	1,671	962	229
Equity in loss of affiliates, net	(16,648)	(24,441)	(14,650)
Other income	1,566	1,891	3,115
INCOME BEFORE INCOME TAXES	497,213	394,886	334,489
INCOME TAX EXPENSE (BENEFIT)	-	1,396	(1,082)
NET INCOME	497,213	393,490	335,571
LESS: NET LOSS ATTRIBUTABLE TO NONCONTROLLING INTEREST	16	-	-
NET INCOME ATTRIBUTABLE TO ALLIANCE RESOURCE PARTNERS, L.P. (NET INCOME OF ARLP)	$ 497,229	$ 393,490	$ 335,571
GENERAL PARTNERS INTEREST IN NET INCOME OF ARLP	$ 138,274	$ 121,349	$ 106,837
LIMITED PARTNERS INTEREST IN NET INCOME OF ARLP	$ 358,955	$ 272,141	$ 228,734
BASIC AND DILUTED NET INCOME OF ARLP PER LIMITED PARTNER UNIT	$ 4.77	$ 3.63	$ 3.06
DISTRIBUTIONS PAID PER LIMITED PARTNER UNIT	$ 2.4725	$ 2.2825	$ 2.08125
WEIGHTED-AVERAGE NUMBER OF UNITS OUTSTANDING BASIC AND DILUTED	74,044,417	73,904,384	73,726,044

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

(In thousands)

	Year Ended December 31,		
	2014	**2013**	**2012**
NET INCOME	$ 497,213	$ 393,490	$ 335,571
OTHER COMPREHENSIVE INCOME (LOSS):			
Defined benefit pension plan			
Net actuarial (loss) gain	(23,821)	12,472	(6,524)
Amortization of actuarial loss (1)	773	2,653	1,788
Total defined benefit pension plan adjustments	(23,048)	15,125	(4,736)
Pneumoconiosis benefits			
Net actuarial (loss) gain	(2,029)	16,750	2,156
Amortization of actuarial (gain) loss (1)	(1,051)	670	776
Total pneumoconiosis benefits adjustments	(3,080)	17,420	2,932
OTHER COMPREHENSIVE (LOSS) INCOME	(26,128)	32,545	(1,804)
COMPREHENSIVE INCOME	471,085	426,035	333,767
Less: Comprehensive loss attributable to noncontrolling interest	16	-	-
COMPREHENSIVE INCOME ATTRIBUTABLE TO ARLP	$ 471,101	$ 426,035	$ 333,767

(1) Amortization of actuarial gain or loss is included in the computation of net periodic benefit cost (see Notes 14 and 18 for additional details).

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

(In thousands)

	Year Ended December 31,		
	2014	**2013**	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 497,213	$ 393,490	$ 335,571
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	274,566	264,911	218,122
Non-cash compensation expense	11,250	8,896	7,428
Asset retirement obligations	2,730	3,004	2,853
Coal inventory adjustment to market	377	2,811	2,978
Equity in loss of affiliates, net	16,648	24,441	14,650
Net (gain) loss on sale of property, plant and equipment	(4,409)	3,475	147
Asset impairment charge	-	-	19,031
Valuation allowance of deferred tax assets	1,636	3,483	-
Other	(5,151)	(6,251)	(3,815)
Changes in operating assets and liabilities:			
Trade receivables	(30,525)	19,062	(44,081)
Other receivables	16	243	1,960
Inventories	(39,103)	(795)	(16,119)
Prepaid expenses and other assets	856	4,290	(8,531)
Advance royalties	4,956	4,492	765
Accounts payable	8,742	(17,755)	7,312
Due to affiliates	(3,104)	(1,343)	4,291
Accrued taxes other than income taxes	365	(937)	4,125
Accrued payroll and related benefits	10,551	8,604	2,625
Pneumoconiosis benefits	3,743	5,944	5,961
Workers compensation	(5,349)	(14,092)	4,075
Other	(6,807)	(1,321)	(3,492)
Total net adjustments	241,988	311,162	220,285
Net cash provided by operating activities	739,201	704,652	555,856
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(307,387)	(329,151)	(424,631)
Changes in accounts payable and accrued liabilities	(2,270)	(3,048)	(4,007)
Proceeds from sale of property, plant and equipment	381	1,520	114
Proceeds from insurance settlement for property, plant and equipment	4,512	-	-
Purchases of equity investments in affiliates	(111,376)	(62,500)	(59,800)
Payment for acquisition of business	-	-	(100,000)
Payments to affiliate for acquisition and development of coal reserves	(4,082)	(25,272)	(34,601)
Payment for acquisition of customer contracts	(11,687)	-	-
Advances/loans to affiliate	-	(7,500)	(5,229)
Payments from affiliate	-	-	4,229
Other	(9,313)	-	546
Net cash used in investing activities	(441,222)	(425,951)	(623,379)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under securitization facility	100,000	-	-
Borrowings under term loan	-	-	250,000
Payments on term loans	(18,750)	-	(300,000)

Borrowings under revolving credit facilities	341,800	386,000	278,800
Payments under revolving credit facilities	(451,800)	(291,000)	(123,800)
Payments on long-term debt	(18,000)	(18,000)	(18,000)
Payments on capital lease obligations	(1,494)	(1,190)	(943)
Payment of debt issuance costs	(263)	-	(4,272)
Contributions to consolidated company from affiliate noncontrolling interest	481	-	-
Net settlement of employee withholding taxes on vesting of Long-Term Incentive Plan	(2,991)	(3,015)	(3,734)
Cash contributions by General Partners	1,611	2,314	2,150
Distributions paid to Partners	(317,626)	(288,439)	(257,923)
Net cash used in financing activities	(367,032)	(213,330)	(177,722)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(69,053)	65,371	(245,245)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	93,654	28,283	273,528
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 24,601	$ 93,654	$ 28,283

See notes to consolidated financial statements, including Note 16 for supplemental cash flow information.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012
(In thousands, except unit data)

	Number of Limited Partner Units	Limited Partners Capital	General Partners Capital (Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Partners Capital
Balance at January 1, 2012	73,551,482	$ 943,325	$ (279,107)	$ (40,460)	$ -	$ 623,758
Comprehensive income:						
Net income	-	228,734	106,837	-	-	335,571
Actuarially determined long-term liability adjustments	-	-	-	(1,804)	-	(1,804)
Total comprehensive income	-	-	-	-	-	333,767
Issuance of units to Long-Term Incentive Plan participants upon vesting	198,416	(3,734)	-	-	-	(3,734)
Common unit based compensation	-	7,428	-	-	-	7,428
Distributions on common unit-based compensation	-	(1,536)	-	-	-	(1,536)
General Partners contributions (Note 13)	-	-	2,150	-	-	2,150
Distributions to Partners	-	(153,394)	(102,993)	-	-	(256,387)
Balance at December 31, 2012	73,749,898	1,020,823	(273,113)	(42,264)	-	705,446
Comprehensive income:						
Net income	-	272,141	121,349	-	-	393,490
Actuarially determined long-term liability adjustments	-	-	-	32,545	-	32,545
Total comprehensive income	-	-	-	-	-	426,035
Issuance of units to Long-Term Incentive Plan participants upon vesting	176,210	(3,015)	-	-	-	(3,015)
Common unit based compensation	-	8,896	-	-	-	8,896
Distributions on common unit-based compensation	-	(1,688)	-	-	-	(1,688)
General Partners contributions (Note 13)	-	-	2,314	-	-	2,314
Distributions to Partners	-	(168,638)	(118,113)	-	-	(286,751)

Balance at December 31, 2013	73,926,108	1,128,519	(267,563)	(9,719)	-	851,237
Comprehensive income:						
Net income (loss)	-	358,955	138,274		(16)	497,213
Actuarially determined long-term liability adjustments	-	-	-	(26,128)	-	(26,128)
Total comprehensive income	-	-	-	-	-	471,085
Issuance of units to Long-Term Incentive Plan participants upon vesting	134,526	(2,991)	-	-	-	(2,991)
Common unit-based compensation	-	11,250	-	-	-	11,250
Distributions on common unit-based compensation	-	(2,182)	-	-	-	(2,182)
General Partners contributions (Note 13)	-	-	1,611	-	-	1,611
Contributions to consolidated company from affiliate noncontrolling interest (Note 11)	-	-	-	-	481	481
Distributions to Partners	-	(183,034)	(132,410)	-	-	(315,444)
Balance at December 31, 2014	74,060,634	$ 1,310,517	$ (260,088)	$ (35,847)	$ 465	$ 1,015,047

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

1. ORGANIZATION AND PRESENTATION

Significant Relationships Referenced in Notes to Consolidated Financial Statements

- References to we, us, our or ARLP Partnership mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.
- References to ARLP mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.
- References to MGP mean Alliance Resource Management GP, LLC, 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.

Organization

ARLP is a Delaware limited partnership listed on the NASDAQ Global Select Market under the ticker symbol ARLP. ARLP was formed in May 1999 to acquire, upon completion of ARLP s initial public offering on August 19, 1999, certain coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation (ARH), consisting of substantially all of ARH s operating subsidiaries, but excluding ARH. ARH 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. SGP, a Delaware limited liability company, is owned by ARH and holds a 0.01% general partner interest in each of ARLP and the Intermediate Partnership.

We are managed by our managing general partner, MGP, a Delaware limited liability company, which holds a 0.99% and a 1.0001% managing general partner interest in ARLP and the Intermediate Partnership, respectively, and a 0.001% managing member interest in Alliance Coal. AHGP is a Delaware limited partnership that was formed to become the owner and controlling member of MGP. AHGP completed its initial public offering (AHGP IPO) on May 15, 2006. AHGP owns directly and indirectly 100% of the members interest of MGP, the incentive distribution rights (IDR) in ARLP and 31,088,338 common units of ARLP.

The Delaware limited partnership, limited liability companies and corporation that comprise our subsidiaries are as follows: Intermediate Partnership, Alliance Coal, Alliance Design Group, LLC, (Alliance Design), Alliance Land, LLC, Alliance Minerals, LLC (Alliance Minerals), Alliance Properties, LLC, Alliance Resource Properties, LLC, (Alliance Resource Properties), AROP Funding, LLC (AROP Funding), ARP Sebree, LLC (ARP Sebree), ARP Sebree South, LLC, Alliance WOR Properties, LLC (WOR Properties), Alliance Service, Inc. (ASI), Alliance WOR Processing, LLC (WOR Processing), Backbone Mountain, LLC, Cavalier Minerals JV, LLC (Cavalier Minerals), CR Services, LLC, Excel Mining, LLC, Gibson County Coal, LLC (Gibson County Coal), Hopkins County Coal, LLC (Hopkins County Coal), Matrix Design Group, LLC (Matrix Design), MC Mining, LLC (MC Mining), Mettiki Coal, LLC (Mettiki (MD)), Mettiki Coal (WV), LLC (Mettiki (WV)), Mt. Vernon Transfer Terminal, LLC (Mt. Vernon), Penn Ridge Coal, LLC (Penn Ridge), Pontiki Coal, LLC (Pontiki), River View Coal, LLC (River View), Sebree Mining, LLC (Sebree Mining), Steamport, LLC, Tunnel Ridge, LLC (Tunnel Ridge), UC Coal, LLC, UC Mining, LLC, UC Processing, LLC, Warrior Coal, LLC (Warrior), Webster County Coal, LLC (Webster County Coal), White County Coal, LLC (White County Coal) and Wildcat Insurance, LLC (Wildcat Insurance).

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The accompanying consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of December 31, 2014 and 2013, and results of our operations, comprehensive income, cash flows and changes in partners capital for each of the three years in the period ended December 31, 2014. All of our intercompany transactions and accounts have been eliminated.

On June 16, 2014, we completed a two-for-one split of our common units, whereby holders of record as of May 30, 2014 received a one unit distribution on each unit outstanding on that date. The unit split resulted in the issuance of 37,030,317 common units. All references to the number of units and per unit net income of ARLP and distribution amounts included in this report have been adjusted to give effect for this unit split for all periods presented. Also, ARLP s partnership agreement was amended effective June 16, 2014, to reduce by half the target thresholds for the incentive distribution rights per unit.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Fair Value of Financial Instruments The carrying amounts for cash equivalents, accounts receivable, accounts payable, due from affiliates and due to affiliates approximate fair value because of the short maturity of those instruments. At December 31, 2014 and 2013, the estimated fair value of our long-term debt, including current maturities, was approximately $833.4 million and $884.8 million, respectively (Note 8).

Cash and Cash Equivalents Cash and cash equivalents include cash on hand and on deposit, including highly liquid investments with maturities of three months or less. We had $0.4 million restricted cash and cash equivalents at December 31, 2014 and no restricted cash or cash equivalents at December 31, 2013.

Cash Management The cash flows from operating activities section of our Consolidated Statements of Cash Flows reflects an adjustment for $1.7 million and $10.3 million representing book overdrafts at December 31, 2014 and 2012, respectively. We had no book overdrafts at December 31, 2013.

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

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

Property, Plant and Equipment Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Interest costs associated with major asset additions are capitalized during the construction period. Maintenance and repairs that do not extend the useful life or increase productivity of the asset are charged to operating expense as incurred. Exploration expenditures are charged to operating expense as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Preparation plants and processing facilities are depreciated using the units-of-production method. Other plant and equipment assets are depreciated principally using the straight-line method over the estimated useful lives of the assets, ranging from 1 to 16 years, limited by the remaining estimated life of each mine. Depreciable lives for mining equipment range from 1 to 16 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 16 years. Gains or losses arising from retirements are included in operating expenses. Depletable lives for mineral rights, assuming current production expectations, range from 1 to 16 years. Depletion of mineral rights is provided on the basis of tonnage mined in relation to estimated recoverable tonnage, which equals estimated proven and probable reserves. Therefore, our mineral rights are depleted based on only proven and probable reserves derived in accordance with Industry Guide 7. At December 31, 2014 and 2013, land and mineral rights include $53.2 million and $45.5 million, respectively, representing the carrying value of coal reserves attributable to properties where we or a third-party to which we lease reserves are not currently engaged in mining operations or leasing to third parties, and therefore, the coal reserves are not currently being depleted. We believe that the carrying value of these reserves will be recovered.

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Mine Development Costs Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized on a units of production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine s production capacity and is not considered to shift the mine into the production phase. At December 31, 2014 and 2013, capitalized mine development costs were $7.0 million and $33.1 million, respectively, representing the carrying value of development costs attributable to properties where we have not reached the production stage of mining operations or leasing to third parties, and therefore, the mine development costs are not currently being amortized. We believe that the carrying value of these development costs will be recovered.

Long-Lived Assets We review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. To the extent the carrying amount is not recoverable based on undiscounted cash flows, the amount of impairment is measured by the difference between the carrying value and the fair value of the asset. We recorded an asset impairment charge of $19.0 million in 2012 (Note 4). No impairment charges were recorded in 2014 and 2013.

Intangible Assets Intangible assets subject to amortization include contracts with covenants not to compete, customer contracts acquired from other parties and mining permits. Intangible assets are amortized on a straight-line basis over their useful life. Intangible assets for customer contracts are amortized on a per unit basis over the terms of the contracts. Amortization expense attributable to intangible assets was $3.0 million, $3.0 million and $2.6 million for the years ending December 31, 2014, 2013 and 2012, respectively. Our intangible assets are included in prepaid expenses and other assets and other long-term assets on our consolidated balance sheets at December 31, 2014 and 2013. Our intangible assets at December 31 are summarized as follows (in thousands):

	December 31, 2014			December 31, 2013		
	Original Cost	**Accumulated Amortization**	**Intangibles, Net**	**Original Cost**	**Accumulated Amortization**	**Intangibles, Net**
Non-compete agreements	$ 15,152	$ (8,545)	$ 6,607	$ 15,236	$ (7,002)	$ 8,234
Customer contracts	17,859	(3,599)	14,260	6,171	(2,301)	3,870
Mining permits	3,843	(182)	3,661	3,843	(116)	3,727
Total	$ 36,854	$ (12,326)	$ 24,528	$ 25,250	$ (9,419)	$ 15,831

Amortization expense attributable to intangible assets is estimated to be $9.6 million in 2015, $6.1 million in 2016, $3.2 million in 2017 and $1.0 million in both 2018 and 2019. The increase in 2015 and 2016 is due to amortization of customer contract intangibles that were acquired at December 31, 2014 and, therefore, had no amortization expense in the periods presented (Note 3).

Advance Royalties Rights to coal mineral leases are often acquired and/or maintained through advance royalty payments. Where royalty payments represent prepayments recoupable against future production, they are recorded as an asset, with amounts expected to be recouped within one year classified as a current asset. As mining occurs on these leases, the royalty prepayments are charged to operating expenses. We assess the recoverability of royalty prepayments based on estimated future production. Royalty prepayments estimated to be nonrecoverable are expensed. Our advance royalties at December 31 are summarized as follows (in thousands):

	2014	2013

Advance royalties, affiliates (Note 19)	$	10,706	$	17,840
Advance royalties, third-parties		14,605		12,427
Total advance royalties	$	25,311	$	30,267

Asset Retirement Obligations We record a liability for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support acreage at surface mines. Examples of these types of

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costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accounting for asset retirement obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. The depreciation is generally determined on a units of production basis and accretion is generally recognized over the life of the producing assets (Note 17). As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free interest rate.

Workers Compensation and Pneumoconiosis (Black Lung) Benefits We are generally self-insured for workers compensation benefits, including black lung benefits. We accrue a workers compensation liability for the estimated present value of workers compensation and black lung benefits based on our actuarially determined calculations (Note 18).

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

Our tax counsel has provided an opinion that ARLP, the Intermediate Partnership and Alliance Coal will each be treated as a partnership. However, as is customary, no ruling has been or will be requested from the Internal Revenue Service (IRS) regarding our classification as a partnership for federal income tax purposes.

Revenue Recognition Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer s analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, we estimate the amount of the quality adjustment and adjust the estimate to actual when the information is provided by the customer. Historically, such adjustments have not been material. Non-coal sales revenues primarily consist of transloading fees, administrative service revenues from our affiliates, mine safety services and products, royalties and throughput fees earned from White Oak Resources LLC (White Oak) (Note 12), other coal contract fees and other handling and service fees. Transportation revenues are recognized in connection with us incurring the corresponding costs of transporting coal to customers through third-party carriers for which we are directly reimbursed through customer billings. We had no allowance for doubtful accounts for trade receivables at December 31, 2014 and 2013.

Pension Benefits Our defined benefit pension obligation and the related benefit cost are accounted for in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 715, *Compensation-Retirement Benefits*. Pension cost and obligations are actuarially determined and are affected by assumptions including expected return on plan assets, discount rates, mortality assumptions, employee turnover rates and retirement dates. We evaluate our assumptions periodically and make adjustments to these assumptions and the recorded liability as necessary (Note 14).

Common Unit-Based Compensation We account for compensation expense attributable to restricted common units granted under the Long-Term Incentive Plan (LTIP), Supplemental Executive Retirement Plan (SERP) and the MGP Amended and Restated Deferred Compensation Plan for Directors (Deferred Compensation Plan) based on the requirements of FASB ASC 718, *Compensation-Stock Compensation*. Accordingly, the fair value of award grants are determined on the grant date of the award and this value is recognized as compensation expense on a pro rata basis for LTIP and SERP awards, as appropriate, over the requisite service period. Compensation expense is fully recognized on the grant date for quarterly distributions credited to SERP accounts and Deferred Compensation Plan awards. The corresponding liability is classified as equity and included in limited partners capital in the consolidated financial statements (Note 15).

Net Income of ARLP Per Unit Basic net income of ARLP per limited partner unit is determined by dividing net income of ARLP available to Limited Partners by the weighted-average number of outstanding common units. Diluted net income of ARLP per unit is based on the combined weighted-average number of common units and common unit equivalents outstanding unless the effect is anti-dilutive (Note 13).

Investments Investments and ownership interests are accounted for under the equity method of accounting if we have the ability to exercise significant influence, but not control, over the entity. Investments accounted for under the equity method are initially recorded at cost, and the difference between the basis of our investment and the underlying equity in the net assets of the joint venture at the investment date, if any, is amortized over the lives of the related assets that gave rise to the difference. In the event our ownership entitles us to a disproportionate sharing of income or loss, our equity in earnings or losses of affiliates is allocated based on the hypothetical liquidation at book value (HLBV) method of accounting. Under the HLBV method, equity in earnings or losses of affiliates is allocated based on the difference between our claim on the net assets of the equity method investee at the end and beginning of the period with consideration of certain eliminating entries regarding differences of accounting for various related party transactions, after taking into account contributions and distributions, if any. Our share of the net assets of the equity method investee is calculated as the amount we would receive if the equity method investee were to liquidate all of its assets at net book value and distribute the resulting cash to creditors, other investors and us according to the respective priorities. Our share of earnings or losses under the HLBV method of accounting from equity method investments and basis difference amortization is reported in the consolidated statements of income as Equity in loss of affiliates, net. We review our investments and ownership interests accounted for under the equity method of accounting for impairment whenever events or changes in circumstances indicate a loss in the value of the investment may be other than temporary. For 2014 and 2013, we determined there were no such material events or changes in circumstances that would indicate the carrying amounts of such investments were not recoverable. Our equity method investments include our ownership interests in White Oak, AllDale Minerals, L.P. (AllDale Minerals) and Mid-America Carbonates, LLC (MAC) (Note 12).

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

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

New Accounting Standards Issued and Not Yet Adopted In April 2014, the FASB issued ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the requirements for reporting discontinued operations in Accounting Standards Codification 205, Presentation of Financial Statements, by updating the criteria for determining which disposals can be presented as discontinued operations and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of discontinued operations. ASU 2014-08 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. We do not anticipate the adoption of ASU 2014-08 on January 1, 2015 will have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (ASU 2014-09). ASU 2014-09 is a new revenue recognition standard that provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the new standard is an entity should recognize revenue to depict the

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transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016 and shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. Early adoption is not permitted. We are currently evaluating the effect of adopting ASU 2014-09.

In August 2014, the FASB issued ASU 2014-15, Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern (ASU 2014-15). ASU 2014-15 provides guidance on management s responsibility in evaluating whether there is substantial doubt about an entity s ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter with early adoption permitted. We do not anticipate the adoption of ASU 2014-15 will have a material impact on our consolidated financial statements.

3. ACQUISITIONS

CONSOL Energy Inc.

In June 2013, our subsidiary, Alliance Resource Properties acquired the rights to approximately 11.6 million tons of proven and probable medium-sulfur coal reserves, and an additional 5.9 million resource tons, in Grant and Tucker Counties, West Virginia from Laurel Run Mining Company, a subsidiary of CONSOL Energy Inc. (CONSOL). The purchase price of $25.2 million was allocated to owned and leased coal rights and was financed using existing cash on hand. As a result of the coal reserve purchase, we reclassified certain tons of medium-sulfur, non-reserve coal deposits as reserves, which together with the reserves purchased above, extended the expected life of Mettiki (WV) s Mountain View mine.

In November 2014, Alliance Resource Properties acquired the rights to approximately 124.2 million tons of proven and probable high-sulfur coal reserves, most of which are leased reserves, and various surface properties in western Kentucky from CNX RCPC, LLC (CNX RCPC) and Island Creek Coal Company (Island Creek), both subsidiaries of CONSOL. The purchase price of $11.6 million was financed using existing cash on hand and allocated to the owned and leased coal rights and surface properties acquired. We also assumed reclamation liabilities totaling $6.0 million.

In conjunction with this acquisition, WKY CoalPlay, LLC (WKY CoalPlay), an entity owned by SGP Land, LLC (SGP Land) and two limited liability companies owned by irrevocable trusts established by our President and Chief Executive Officer (Craft Companies), acquired approximately 86.6 million tons of proven and probable high-sulfur owned coal reserves in western Kentucky and southern Indiana through its purchase of two wholly owned subsidiaries of CNX RCPC and Island Creek for $57.2 million. In December 2014, WKY CoalPlay s subsidiaries leased 72.3 million tons of the acquired reserves to us and, as partial consideration for entering the leases, conveyed the remaining 14.3 million tons of its acquired reserves to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a mine plan. See Note 19 for further information on our related party transactions and lease terms with WKY CoalPlay. The reserves described in this paragraph extended the expected lives of our River View and Dotiki mines and provide potential greenfield mining opportunities.

Peabody Energy Corporation

In December 2014, Alliance Resource Properties acquired the rights to approximately 86.2 million tons of proven and probable high-sulfur leased coal reserves in western Kentucky from Midwest Coal Reserves of Kentucky, LLC (Midwest) and Cyprus Creek Land Company, both subsidiaries of Peabody Energy Corporation (Peabody), in exchange for an overriding royalty to be paid to Peabody based on a percentage of the sales price of coal mined from the reserves acquired. In addition, WKY CoalPlay acquired the rights to approximately 54.1 million tons of owned coal reserves in western Kentucky, through its purchase of a wholly owned subsidiary of Midwest for $29.6 million cash paid at closing. In conjunction with this acquisition, WKY CoalPlay s subsidiary leased 22.6 million tons of the acquired reserves to us and, as partial consideration for entering the lease, conveyed the remaining 31.5 million tons to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a mine plan. See Note 19 for further information on our related party transactions and lease terms with WKY CoalPlay. This transaction allowed us to extend the expected life of our River View mine and provides potential greenfield mining opportunities.

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Patriot Coal Corporation

On December 31, 2014 (the Initial Closing Date), we entered into asset purchase agreements with Patriot Coal Corporation (Patriot) regarding certain assets relating to two of Patriot s western Kentucky mining operations, including certain coal sales agreements, unassigned coal reserves and underground mining equipment and infrastructure. Both of the mining operations the former Dodge Hill and Highland mining operations were closed by Patriot in late 2014 prior to entering into these agreements. Also on December 31, 2014, Patriot affiliates entered into agreements to sell other assets from Highland to a third party. Additional details of the transactions are discussed below.

On the Initial Closing Date, our subsidiary, Alliance Coal acquired the rights to certain coal supply agreements from an affiliate of Patriot for approximately $21.0 million. Of the $21.0 million purchase price, $9.3 million was paid into escrow subject to obtaining certain consents and is included in Other cash flows from investing activities on our consolidated statements of cash flows and in Prepaid expenses and other assets on our consolidated balance sheets. In February 2015, $7.5 million of the escrowed amount was released to Patriot for a consent received and $1.8 million was returned to Alliance Coal as a result of a consent not received, reducing our purchase price to $19.2 million. The acquired agreements provide for delivery of approximately 5.1 million tons of coal from 2015 through 2017.

On February 3, 2015 (the Subsequent Closing Date), Alliance Coal and Alliance Resource Properties acquired from Patriot an estimated 84.1 million tons of proven and probable high-sulfur coal reserves in western Kentucky (substantially all of which was leased by Patriot), and substantially all of Dodge Hill s assets related to its former coal mining operation in western Kentucky, which principally included underground mining equipment and an estimated 43.2 million tons of non-reserve coal deposits (substantially all of which was leased by Dodge Hill). In addition, we assumed Dodge Hill s reclamation liabilities totaling $2.5 million. Also on the Subsequent Closing Date, the Intermediate Partnership s newly formed subsidiaries, UC Mining, LLC and UC Processing, LLC, acquired certain underground mining equipment and spare parts inventory from Patriot s former Highland mining operation.

The mining and reserve assets acquired from Patriot described above are located in Union and Henderson Counties, Kentucky. The mining equipment, spare parts and underground infrastructure that we acquired from Patriot will be dispersed to our existing operations in the Illinois Basin region in accordance with their highest and best use. Our purchase price of $19.2 million and $20.5 million paid on the Initial Closing Date and the Subsequent Closing Date, respectively, described above was financed using existing cash on hand. As we have no intentions of operating the former Dodge Hill mining complex as a business and only acquired certain assets of Highland, we believe unaudited pro forma information of revenue and earnings is not meaningful as it relates to the acquisition of Patriot assets described above and furthermore not materially different than revenue and earnings as presented in our consolidated statements of income. The primary ongoing benefit derived from the transaction relates to the coal supply agreements acquired, which would have permitted the sale of 3.2 million tons at average pricing of $46.67 per ton sold during 2014 based on the contract price and sales volumes, if we had owned the contracts during 2014.

In conjunction with our acquisitions on the Subsequent Closing Date, WKY CoalPlay acquired approximately 39.1 million tons of proven and probable high-sulfur owned coal reserves located in Henderson and Union Counties, Kentucky from Central States Coal Reserves of Kentucky, LLC (Central States), a wholly owned subsidiary of Patriot, for $25.0 million and in turn leased those reserves to us (Note 19). Also on the Subsequent Closing Date, Patriot sold certain mining equipment at Highland that we did not acquire to a third party. We anticipate that later in 2015, Patriot will complete the sale of reserves and surface and underground facilities at the former Highland mining operation to this same third party.

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The following table summarizes the consideration paid by us to Patriot on the Initial and Subsequent Closing Dates and the preliminary fair value allocation of assets acquired and liabilities assumed as valued at the respective acquisition dates (in thousands):

Consideration paid	$	39,688
Recognized amounts of net tangible and intangible assets acquired and liabilities assumed:		
Inventories		3,255
Property, plant and equipment, including mineral rights and leased equipment		19,740
Customer contracts, net		19,193
Asset retirement obligation		(2,500)
Net tangible and intangible assets acquired	$	39,688

Intangible assets related to coal supply agreements will be amortized over the weighted-average term of the contracts. We are currently in the process of evaluating the fair values of the assets acquired and liabilities assumed from Patriot. As a result, the purchase price allocation above is preliminary pending completion of our final evaluation of all assets acquired and liabilities assumed.

With the reserve acquisitions made in 2014 and 2015 discussed above, we were able to reclassify approximately 85.0 million tons of controlled non-reserve coal deposits to reserves, resulting in a total increase of coal reserves of approximately 537.2 million tons. These acquisitions provide for potential greenfield mining opportunities and extend the expected lives of our River View and Dotiki mines. Depreciation, depletion and amortization of certain assets at these mines will be adjusted as appropriate to reflect the extended lives.

Green River Collieries, LLC

On April 2, 2012, we acquired substantially all of Green River Collieries, LLC s (Green River) assets related to its coal mining business and operations located in Webster and Hopkins Counties, Kentucky. The transaction includes the Onton No. 9 mining complex (Onton mine), which includes the mine, a dock, tugboat, and a lease for the preparation plant, and an estimated 40.0 million tons of coal reserves in the West Kentucky No. 9 coal seam. The Green River acquisition is consistent with our general business strategy and complements our current coal mining operations.

The following table summarizes the consideration paid to Green River and the final fair value allocation of assets acquired and liabilities assumed at the acquisition date (in thousands):

Consideration paid	$	100,000
Recognized amounts of net tangible and intangible assets acquired and liabilities assumed:		

Inventories		547
Advance royalties		888
Property, plant and equipment, including mineral rights and leased facilities		117,110
Noncompete agreement		1,200
Customer contracts, net		4,955
Permits		843
Capital lease obligation		(17,384)
Asset retirement obligation		(6,032)
Pneumoconiosis benefits		(2,127)
Net tangible and intangible assets acquired	$	100,000

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During the quarter ended September 30, 2012, we finalized the purchase price allocation related to the assets acquired and liabilities assumed from Green River. The adjustments to the preliminary fair values resulted from additional information obtained about facts in existence on April 2, 2012. Prior financial statements have not been retrospectively adjusted due to immateriality.

Intangible assets and liabilities related to coal supply agreements are being amortized over the average term of the contracts. Mine permits will be amortized over the estimated useful life of the Onton mine and the noncompete agreement will be amortized over the term of the agreement.

As the Green River acquisition occurred on April 2, 2012, we believe unaudited pro forma information of revenue and earnings is not materially different than revenue and earnings as presented in our consolidated statements of income.

4. ASSET IMPAIRMENT CHARGE

Pontiki s mining complex in Martin County, Kentucky was idled from August 29, 2012 to November 25, 2012 following an Mine Safety and Health Administration (MSHA) closure order. This idling together with ongoing market uncertainty and the likelihood of future cost increases arising from stringent regulatory oversight placed the long-term viability of Pontiki at significant risk. As a result of these events, we recorded an asset impairment charge of $19.0 million during the quarter ended September 30, 2012 to reduce the carrying value of the asset group representing the Pontiki mining complex (Pontiki Assets) to an estimated fair value of $16.1 million which was determined using the market and cost valuation techniques and represents a Level 3 fair value measurement. Although the Pontiki mining complex resumed production operations, we subsequently ceased operations at the Pontiki mining complex in late November 2013. Many of Pontiki s employees and some of its equipment were migrated to our MC Mining and other operations. No additional impairment was required related to the closure of the mine in 2013. We sold most of the remaining assets at the Pontiki mining complex in May 2014.

5. INVENTORIES

Inventories consist of the following at December 31, (in thousands)**:**

	2014	2013
Coal	$ 50,130	$ 12,791
Supplies (net of reserve for obsolescence of $2,935 and $3,150, respectively)	33,025	31,423
Total inventory	$ 83,155	$ 44,214

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following at December 31, (in thousands):

	2014	2013
Mining equipment and processing facilities	$ 1,757,772	$ 1,583,329
Land and mineral rights	376,937	369,347
Buildings, office equipment and improvements	278,283	226,672
Construction and mine development in progress	82,530	194,221
Mine development costs	320,098	272,303
Property, plant and equipment, at cost	2,815,620	2,645,872
Less accumulated depreciation, depletion and amortization	(1,150,414)	(1,031,493)
Total property, plant and equipment, net	$ 1,665,206	$ 1,614,379

Equipment leased by us under lease agreements which are determined to be capital leases are stated at an amount equal to the present value of the minimum lease payments during the lease term, less accumulated amortization. Equipment under capital leases totaling $20.9 million included in mining equipment and processing facilities is amortized on the straight-line method over the shorter of its useful life or the related lease term. The provision for amortization of leased properties is included in depreciation, depletion and amortization expense. Accumulated amortization related to our capital leases was $5.6 million and $5.8 million as of December 31, 2014 and 2013, respectively, and amortization expense was $1.6 million, $2.0 million and $1.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. For information regarding the impairment of assets at the Pontiki mine, please see Note 4.

7. LONG-TERM DEBT

Long-term debt consists of the following at December 31, (in thousands):

	2014	2013
Revolving Credit facility	$ 140,000	$ 250,000
Senior notes	-	18,000
Series A senior notes	205,000	205,000
Series B senior notes	145,000	145,000
Term loan	231,250	250,000
Securitization facility	100,000	-
	821,250	868,000
Less current maturities	(230,000)	(36,750)
Total long-term debt	$ 591,250	$ 831,250

Credit Facility. On May 23, 2012, our Intermediate Partnership entered into a credit agreement (the Credit Agreement) with various financial institutions for a revolving credit facility (the Revolving Credit Facility) of $700.0 million and a term loan (the Term Loan) in the aggregate principal amount of $250.0 million (collectively, the Revolving Credit Facility and Term Loan are referred to as the Credit Facility). Borrowings under the Credit Agreement bear interest at a Base Rate or Eurodollar Rate, at our election, plus an applicable margin that fluctuates depending upon the ratio of Consolidated Debt to Consolidated Cash Flow (each as defined in the Credit Agreement). We have elected a Eurodollar Rate, which, with applicable margin, was 1.57% on borrowings outstanding as of December 31, 2014. The Credit Facility matures May 23, 2017, at which time all amounts then outstanding are required to be repaid. Interest is payable quarterly, with principal of the Term Loan due as follows: for each quarter commencing June 30, 2014 and ending March 31, 2016, quarterly principal payments in an amount per quarter equal to 2.50% of the aggregate amount of the Term Loan advances outstanding; for each quarter beginning June 30, 2016 through December 31, 2016, 20% of the aggregate amount of the Term Loan advances outstanding; and the remaining balance of the Term Loan advances at maturity. In June 2014, we began making quarterly principal payments on the Term Loan, leaving a balance of $231.3 million at December 31, 2014. We have the option to prepay the Term Loan at any time in whole or in part subject to terms and conditions described in the Credit Agreement. Upon a change of control (as defined in the Credit Agreement), the unpaid principal amount of the Credit Facility, all interest thereon and all other amounts payable under the Credit Agreement would become due and payable.

At December 31, 2014, we had borrowings of $140.0 million and $5.4 million of letters of credit outstanding with $554.6 million available for borrowing under the Revolving Credit Facility. We utilize the Revolving Credit Facility, as appropriate, for working capital requirements, capital expenditures, debt payments and distribution payments. We incur an annual commitment fee of 0.20% on the undrawn portion of the Revolving Credit Facility.

We incurred debt issuance costs of approximately $4.3 million in 2012 associated with the Credit Agreement, which have been deferred and are being amortized as a component of interest expense over the duration of the Credit Agreement. We also expensed $1.1 million in 2012 of previously deferred debt issuance cost associated with our previous $300 million term loan.

Series A Senior Notes. On June 26, 2008, our Intermediate Partnership entered into a Note Purchase Agreement (the 2008 Note Purchase Agreement) with a group of institutional investors in a private placement offering. We issued $205.0 million of Series A senior notes, which bear interest at 6.28% and mature on June 26, 2015 with interest payable semi-annually.

Series B Senior Notes. On June 26, 2008, we issued under the 2008 Note Purchase Agreement $145.0 million of Series B senior notes (together with the Series A senior notes, the 2008 Senior Notes), which bear interest at 6.72% and mature on June 26, 2018 with interest payable semi-annually.

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The 2008 Senior Notes and the Credit Facility described above (collectively, ARLP Debt Arrangements) are guaranteed by all of the material direct and indirect subsidiaries of our Intermediate Partnership. The ARLP Debt Arrangements contain various covenants affecting our Intermediate Partnership and its subsidiaries restricting, among other things, the amount of distributions by our Intermediate Partnership, incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates, in each case subject to various exceptions. The ARLP Debt Arrangements also require the Intermediate Partnership to remain in control of a certain amount of mineable coal reserves relative to its annual production. In addition, the ARLP Debt Arrangements require our Intermediate Partnership to maintain (a) debt to cash flow ratio of not more than 3.0 to 1.0 and (b) cash flow to interest expense ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt to cash flow ratio and cash flow to interest expense ratio were 1.01 to 1.0 and 24.0 to 1.0, respectively, for the trailing twelve months ended December 31, 2014. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2014.

Accounts Receivable Securitization. On December 5, 2014, certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership entered into a $100.0 million accounts receivable securitization facility (Securitization Facility) providing additional liquidity and funding. Under the Securitization Facility, certain subsidiaries sell trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to $100.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a Eurodollar Rate. The Securitization Facility has an initial term of 364 days, however we have the contractual ability and the intent to extend the term for an additional 364 days. At December 31, 2014, we had $100.0 million outstanding under the Securitization Facility. Debt issuance costs were immaterial for the transaction.

Other. In addition to the letters of credit available under the Credit Facility discussed above, we also have agreements with two banks to provide additional letters of credit in an aggregate amount of $31.1 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers compensation benefits. At December 31, 2014, we had $30.7 million in letters of credit outstanding under agreements with these two banks.

Aggregate maturities of long-term debt are payable as follows (in thousands):

Year Ending December 31,		
2015	$	230,000
2016		256,250
2017		190,000
2018		145,000
2019		-
Thereafter		-
	$	821,250

8. FAIR VALUE MEASUREMENTS

We apply the provisions of FASB ASC 820, *Fair Value Measurement*, which, among other things, defines fair value, requires disclosures about assets and liabilities carried at fair value and establishes a hierarchal disclosure framework based upon the quality of inputs used to measure fair value.

Valuation techniques are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our own market assumptions.

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These two types of inputs create the following fair value hierarchy:

- Level 1 Quoted prices for identical instruments in active markets.

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

- Level 3 Instruments whose significant value drivers are unobservable.

The carrying amounts for cash equivalents, accounts receivable, accounts payable, due from affiliates and due to affiliates approximate fair value because of the short maturity of those instruments. At December 31, 2014 and 2013, the estimated fair value of our long-term debt, including current maturities, was approximately $833.4 million and $884.8 million, respectively, based on interest rates that we believe are currently available to us for issuance of debt with similar terms and remaining maturities (see Note 7). The fair value of debt, which is based upon interest rates for similar instruments in active markets, is classified as a Level 2 measurement under the fair value hierarchy.

9. DISTRIBUTIONS OF AVAILABLE CASH

We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partners. Available cash is generally defined in the partnership agreement as all cash and cash equivalents on hand at the end of each quarter less reserves established by our managing general partner in its reasonable discretion for future cash requirements. These reserves are retained to provide for the conduct of our business, the payment of debt principal and interest and to provide funds for future distributions.

As quarterly distributions of available cash exceed the target distribution levels established in our partnership agreement, our managing general partner receives distributions based on specified increasing percentages of the available cash that exceeds the target distribution levels. The target distribution levels are based on the amounts of available cash from our operating surplus distributed for a given quarter that exceed the minimum quarterly distribution (MQD) and common unit arrearages, if any. Our partnership agreement defines the MQD as $0.125 per unit ($0.50 per unit on an annual basis).

Under the quarterly IDR provisions of our partnership agreement, our managing general partner is entitled to receive 15% of the amount we distribute in excess of $0.1375 per unit, 25% of the amount we distribute in excess of $0.15625 per unit, and 50% of the amount we distribute in excess of $0.1875 per unit. For the years ended December 31, 2014, 2013 and 2012, we allocated to our managing general partner incentive distributions of $129.8 million, $115.6 million and $102.1 million, respectively. The following table summarizes the quarterly per unit distribution paid during the respective quarter:

	Year		
	2014	2013	2012
First Quarter	$0.59875	$0.55375	$0.49500
Second Quarter	$0.61125	$0.56500	$0.51250
Third Quarter	$0.62500	$0.57625	$0.53125
Fourth Quarter	$0.63750	$0.58750	$0.54250

On January 28, 2015, we declared a quarterly distribution of $0.65 per unit, totaling approximately $83.6 million (which includes our managing general partner s incentive distributions), on all our common units outstanding, which was paid on February 13, 2015, to all unitholders of record on February 6, 2015.

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10. INCOME TAXES

Our subsidiaries, ASI and Wildcat Insurance, are subject to federal and state income taxes. Wildcat Insurance s income is due to insurance premiums provided by our other subsidiaries. ASI s income is principally due to its subsidiary, Matrix Design. There are minor temporary differences between our taxable entities financial reporting basis and the tax basis of their assets and liabilities. Components of income tax expense (benefit) are as follows (in thousands):

	Year Ended December 31, 2014	2013	2012
Current:			
Federal	$ -	$ 7	$ (37)
State	-	16	(183)
	-	23	(220)
Deferred:			
Federal	-	1,022	(753)
State	-	351	(109)
	-	1,373	(862)
Income tax expense (benefit)	$ -	$ 1,396	$ (1,082)

We have deferred tax assets due to net operating losses and research and development credits associated with ASI s operations in the amount of $6.5 million, partially offset by liabilities of $1.3 million. State and federal valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. During 2014, the federal and state valuation allowances increased to $4.0 million and $1.2 million, respectively, primarily due to the ongoing evaluation process of the losses and credits anticipated to be realized in future years.

Reconciliations from the provision for income taxes at the U.S. federal statutory tax rate to the effective tax rate for the provision for income taxes are as follows (in thousands):

	Year Ended December 31, 2014	2013	2012
Income taxes at statutory rate	$ 174,024	$ 138,210	$ 117,057
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(174,912)	(139,771)	(117,767)
Increase/(decrease) resulting from:			
State taxes, net of federal income tax	(112)	(192)	(83)
Change in valuation allowance of deferred tax assets	1,636	3,483	-
Other	(636)	(334)	(289)
Income tax expense (benefit)	$ -	$ 1,396	$ (1,082)

11. NONCONTROLLING INTEREST

On November 10, 2014 (the Cavalier Formation Date), our wholly owned subsidiary, Alliance Minerals and Bluegrass Minerals Management, LLC (Bluegrass Minerals) entered into a limited liability company agreement (the Cavalier Agreement) to form Cavalier Minerals. Cavalier Minerals was formed to indirectly acquire oil and gas mineral interests through its noncontrolling ownership interest in AllDale Minerals. Alliance Minerals and Bluegrass Minerals committed funding of $48.0 million and $2.0 million, respectively, to Cavalier Minerals. Alliance Minerals contributions through December 31, 2014 to Cavalier Minerals totaled $11.5 million, leaving a remaining commitment to Cavalier Minerals of $36.5 million at December 31, 2014, which we expect to fund over the next two to four years.

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We expect to fund this additional commitment utilizing existing cash balances, future cash flows from operations, borrowings under credit and securitization facilities and cash provided from the issuance of debt or equity. Bluegrass Minerals, which is owned and controlled by an officer of ARH and is Cavalier Minerals managing member, contributed $0.5 million as of December 31, 2014 and has a remaining commitment of $1.5 million. Cavalier Minerals has committed to provide funding of $49.0 million to AllDale Minerals. Cavalier Minerals has and will continue to provide funding to AllDale Minerals using contributions from Alliance Minerals and Bluegrass Minerals (Note 12).

In accordance with the Cavalier Agreement, Bluegrass Minerals is entitled to receive an incentive distribution from Cavalier Minerals equal to 25.0% of all distributions (including in liquidation) after return of members capital reduced by certain distributions received by Bluegrass Minerals or its owner from AllDale Minerals Management, LLC (AllDale Minerals Management) (Note 12). Alliance Minerals ownership interest in Cavalier Minerals at December 31, 2014 was 96.0%. The remainder of the equity ownership is held by Bluegrass Minerals. As of December 31, 2014, Cavalier Minerals had not made any distributions to its owners. We have consolidated Cavalier Minerals financial results in accordance with FASB ASC 810, *Consolidation*. Based on the guidance in FASB ASC 810, we concluded that Cavalier Minerals is a VIE and we are the primary beneficiary because our consent is required for significant activities of Cavalier Minerals and due to Bluegrass Minerals relationship to us as described above. Bluegrass Minerals equity ownership of Cavalier Minerals is accounted for as noncontrolling ownership interest in our consolidated balance sheets. In addition, earnings attributable to Bluegrass Minerals is recognized as noncontrolling ownership interest in our consolidated statements of income.

12. EQUITY INVESTMENTS

White Oak

On September 22, 2011 (the Transaction Date), we entered into a series of transactions with White Oak and related entities to support development of a longwall mining operation. The initial longwall system commenced operation in late October 2014. The transactions with White Oak feature several components, including an equity investment in White Oak (represented by Series A Units containing certain distribution and liquidation preferences), the acquisition and lease-back of certain coal reserves and surface rights and a construction loan. Our initial investment funding to White Oak at the Transaction Date, consummated utilizing existing cash on hand, was $69.5 million and we have funded White Oak $320.5 million between the Transaction Date and December 31, 2014. Inclusive of this funding, we expect to fund to White Oak a total of approximately $395.5 million to $415.5 million from the Transaction Date through December 31, 2015. We expect to fund additional commitments utilizing existing cash balances, future cash flows from operations, borrowings under credit and securitization facilities and cash provided from the issuance of debt or equity. On the Transaction Date, we also entered into a coal handling and preparation agreement, pursuant to which we constructed and are operating a preparation plant and other surface facilities. The following information discusses each component of these transactions in further detail.

Hamilton County, Illinois Reserve Acquisition

On the Transaction Date, WOR Properties acquired from White Oak the rights to approximately 204.9 million tons of proven and probable high-sulfur coal reserves, of which 105.2 million tons have been developed for mining by White Oak, and certain surface properties and rights in Hamilton County, Illinois (the Reserve Acquisition), which is adjacent to White County, Illinois, where our Pattiki mine is located. The asset purchase price of $33.8 million cash paid at closing was allocated to owned and leased coal rights. Between the Transaction Date and December 31, 2012, WOR Properties provided $51.6 million to White Oak for development of the acquired coal reserves, fulfilling its initial commitment for further development funding. During the twelve months ended December 31, 2013, WOR Properties acquired from White Oak, for $25.3 million cash paid at various closings, an additional 90.1 million tons of reserves. During the twelve months ended December 31, 2014, WOR Properties acquired from White Oak, for $4.1 million cash paid at various closings, an additional 14.6 million tons of reserves. Of the additional tons acquired in 2014 and 2013, 53.4 million tons have been developed for mining by White Oak. At December 31, 2014, WOR Properties had provided $114.8 million to acquire a total of 309.6 million tons of coal reserves and fund the development of the acquired reserves. WOR Properties has a remaining commitment of $25.2 million for additional coal reserve acquisitions. In conjunction with the Reserve Acquisition and the additional reserve acquisitions discussed above, WOR Properties entered into leases with White Oak, which provide White Oak the rights to develop and mine the acquired reserves. The leases require, in consideration of the lease-back of the coal reserves and the funding of development of those coal reserves, White Oak to pay WOR Properties earned royalties and, during the period beginning January 1, 2015 and ending December 31, 2034, fully recoupable minimum royalty totaling $2.1 million per month. The lease terms are

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through December 31, 2034, subject to certain renewal options for White Oak. In December 2014, we received the first minimum royalty payment of $2.1 million from White Oak, against which earned royalties for the period prior to January 1, 2015 will be credited. Unearned minimum royalty payments from White Oak are reflected in the Other current liabilities and Other liabilities line items in our consolidated balance sheets.

Series A Units

Concurrent with the Reserve Acquisition, WOR Processing made an initial equity investment of $35.7 million in White Oak to purchase Series A Units representing ownership in White Oak. White Oak and WOR Processing agreed to an additional investment in Series A Units by WOR Processing of at least $114.3 million (for a minimum total of $150.0 million), and WOR Processing committed to invest up to an additional $125.0 million in Series A Units (for a maximum total of $275.0 million) to the extent required for development or operation of the White Oak Mine No. 1 mine, and subject to certain rights and obligations of other White Oak owners to participate in such investment. WOR Processing purchased $129.3 million of additional Series A Units between the Transaction Date and December 31, 2013, fulfilling WOR Processing s minimum initial commitment of $150.0 million. During the year ended December 31, 2014, WOR Processing purchased $99.8 million of additional Series A units, bringing our total investment in Series A units to $264.8 million at December 31, 2014. Additional equity investments in Series A and B units of $39.8 million and $45.9 million were made by another White Oak owner in 2014 and 2013, respectively. In 2015, through February 13, 2015, WOR Processing has purchased $6.0 million of additional Series A Units.

The Series A Units are entitled to receive 100% of all distributions made by White Oak until such time as the Series A Units have realized a defined minimum return, after which the Series A Units will receive distributions based on a participation percentage determined in accordance with the White Oak operating agreement. In addition, the Series A Units contain certain liquidation preferences that require, upon an event of liquidation, the minimum return provision must be satisfied on a priority basis over other classes of White Oak equity. WOR Processing s ownership interest and distribution participation percentage in White Oak may increase with additional investments in the Series A Units up to a maximum of 40.0% for an investment of $275.0 million in the Series A Units. WOR Processing s ownership and member s voting interest in White Oak at December 31, 2014 and 2013 was 39.0% and 21.6%, respectively, based upon currently outstanding voting units. The remainder of the equity ownership in White Oak, represented by Series A and B Units, is held by other investors and members of White Oak management.

There are four primary activities we believe most significantly impact White Oak s economic performance. These primary activities are associated with financing, capital, operating and marketing of White Oak s development and operation of the mine areas covered by the agreements. We have various protective or participating rights related to these primary activities, such as minority representation on White Oak s board of directors, restrictions on indebtedness and other obligations, the ability to assume control of White Oak s board of directors in certain circumstances, such as an event of default by White Oak, and the right to approve certain coal sales agreements that represent a significant concentration of White Oak s coal sales, among others. Currently, we have two representatives on White Oak s board of directors, which consists of five board members. We continually review all rights provided to WOR Processing and us by various agreements with White Oak and continue to conclude that all such rights are protective or participating in nature and do not provide WOR Processing or us the ability to unilaterally direct any of the primary activities of White Oak that most significantly impact its economic performance. However, the agreements provide us the ability to exert significant influence over these activities. As such, we recognize WOR Processing s interest in White Oak as an equity investment in affiliate in our consolidated balance sheets. We account for WOR Processing s ownership interest in White Oak under the equity method of accounting, with recognition of its ownership interest in the income or loss of White Oak as equity in income/(loss) in our consolidated statements of income. As of December 31, 2014, WOR Processing had invested $264.8 million in Series A Units of White Oak equity, which represents our current maximum exposure to loss as a result of our equity investment in White Oak exclusive of capitalized interest. As of December 31, 2014, White Oak has made no distributions to us.

We record WOR Processing s equity in income or losses of affiliates under the HLBV method of accounting due to the preferences to which WOR Processing is entitled to receive on distributions. Under the HLBV method, we determine WOR Processing s share of White Oak income or losses by determining the difference between its claim to White Oak s book value at the end of the period as compared to the beginning of the period with consideration of certain eliminating entries regarding differences of accounting for various related party transactions between us and White Oak. WOR Processing s claim on White Oak s book value is calculated as the amount it would receive if White Oak were to liquidate all of its assets at recorded amounts determined in accordance with GAAP and distribute the resulting cash to creditors, other investors and WOR Processing according to the respective priorities. For the twelve months ended

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December 31, 2014 and 2013, we were allocated losses of $16.6 million and $25.3 million, respectively. Allocated losses from White Oak in 2014 were reduced by, and are reflected net of $11.6 million due to the impact of purchases of Series A Units during the period by another White Oak owner. Series A Unit purchases impact the future preferred distributions allocable to each owner and the ongoing allocation of income and losses for GAAP purposes under the HLBV method.

Services Agreement

Simultaneous with the closing of the Reserve Acquisition, WOR Processing entered into a Coal Handling and Preparation Agreement (Services Agreement) with White Oak pursuant to which WOR Processing committed to construct and operate a coal preparation plant and related facilities and a rail loop and loadout facility to service the White Oak Mine No. 1. The Services Agreement requires White Oak to pay a throughput fee for these services of $5.00 per ton of feedstock coal processed through the preparation plant up to a minimum throughput quantity (and, beginning in January 2015, to pay any deficiency if less than the minimum tonnage is throughput) and $2.40 per ton for quantities in excess of the minimum throughput quantity. The minimum throughput quantity is 666,667 tons of feedstock coal per month. The term of the Services Agreement is through December 31, 2034. During the year ended December 31, 2013, WOR Processing began processing and loading coal through the facilities. WOR Processing earned throughput fees of $19.6 million and $2.1 million for the years ended December 31, 2014 and 2013, respectively, for processing and loading coal through the facilities. Throughput fees earned from White Oak are included in Other sales and operating revenues on our consolidated statements of income.

In addition, the Intermediate Partnership agreed to loan $10.5 million to White Oak for the construction of various assets on the surface property, including a bathhouse, office and warehouse (Construction Loan). The Construction Loan has a term of 20 years, with repayment scheduled to begin in 2015. White Oak had borrowed the entire amount available under the Construction Loan as of December 31, 2014.

Equipment Financing Commitment

Also on the Transaction Date, the Intermediate Partnership committed to provide $100.0 million of fully collateralized equipment financing with a five-year term to White Oak for the purchase of coal mining equipment should other third-party funding sources not be available. During the second quarter of 2012, White Oak obtained third-party financing for the purchase of coal mining equipment, and on June 18, 2012, repaid the Intermediate Partnership the outstanding amount of $2.2 million for previous advances and interest due. White Oak also terminated early the equipment financing agreement with the Intermediate Partnership, and as part of the termination, paid the Intermediate Partnership a $2.0 million cancellation fee on June 18, 2012.

AllDale Minerals

On the Cavalier Formation Date, Cavalier Minerals (Note 11) contributed $7.4 million in return for a limited partner interest in AllDale Minerals, an entity created to purchase oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. Between the Cavalier Formation Date and December 31, 2014, Cavalier Minerals contributed $4.2 million to AllDale Minerals. Cavalier Minerals has a remaining commitment to AllDale Minerals of $37.4 million at December 31, 2014, which it expects to fund over the next two to four years. AllDale Minerals is managed and controlled by its general partner, AllDale Minerals Management. AllDale Minerals Management is owned by four members, consisting of three parties unrelated to us or our affiliates and Bluegrass Minerals, which as noted above is owned by an officer of ARH. Bluegrass Minerals does not individually possess the controlling interest of AllDale Minerals Management. Due to Cavalier Minerals significant ownership interest in AllDale Minerals, we have recognized Cavalier Minerals limited partner interest in AllDale Minerals as an equity investment in affiliate in our consolidated balance sheets. We account for Cavalier Minerals ownership interest in the income or loss of AllDale Minerals as equity income or loss in our consolidated statements of income. We record equity income or loss based on AllDale Minerals distribution structure. Cavalier Minerals limited partner interest in AllDale Minerals was 71.7% at December 31, 2014. The remainder of the equity ownership is held by other limited partners and AllDale Minerals Management. For the period from the Cavalier Formation Date through December 31, 2014, we have been allocated losses of $0.4 million from AllDale Minerals.

In accordance with AllDale Minerals partnership agreement, limited partners, such as Cavalier Minerals, will initially receive all distributions of proceeds from certain producing basins based upon the greater of the limited partner s cumulative contributions plus 25.0% or an amount sufficient to cause the limited partner to receive an effective internal

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rate of return of 10.0%. Afterwards, 20.0% of all distributions will be allocated to AllDale Minerals Management, as an incentive distribution to the general partner, with the remaining 80.0% allocated to limited partners based upon ownership percentages. In addition, upon an event of liquidation, any proceeds will be distributed using the same methodology. As of December 31, 2014, AllDale Minerals has not made any distributions to its owners.

MAC

In March 2006, White County Coal, and Alexander J. House entered into a limited liability company agreement to form MAC. MAC was formed to engage in the development and operation of a rock dust mill and to manufacture and sell rock dust. White County Coal initially invested $1.0 million in exchange for a 50% equity interest in MAC. Our equity investment in MAC was $1.6 million at December 31, 2014. Effective on January 1, 2015, we purchased the remaining 50.0% equity interest in MAC from Mr. House for $5.5 million cash paid at closing.

Summarized Financial Information

White Oak s results for the years ended December 31, 2014, 2013 and 2012, are summarized as follows (in thousands):

	2014	**2013**	**2012**
Total revenues	$ 42,748	$ -	$ -
Gross loss	(1,134)	(5,404)	(7)
Loss from operations	(21,018)	(24,103)	(16,037)
Net loss	(46,324)	(30,263)	(16,884)

White Oak s financial position for the years ended December 31, 2014 and 2013 are summarized as follows (in thousands):

	2014	**2013**
Current assets	$ 37,105	$ 11,228
Noncurrent assets	639,953	533,696
Current liabilities	71,489	50,668
Noncurrent liabilities	372,507	354,597

13. NET INCOME OF ARLP PER LIMITED PARTNER UNIT

We apply the provisions of FASB ASC 260, *Earnings Per Share*. As required by FASB ASC 260, we apply the two-class method in calculating earnings per unit (EPU) Net income of ARLP is allocated to the general partners and limited partners in accordance with their respective partnership percentages, after giving effect to any special income or expense allocations, including incentive distributions to our managing general partner, the holder of the IDR pursuant to our partnership agreement, which are declared and paid following the end of each quarter (Note 9). Under the quarterly IDR provisions of our partnership agreement, our managing general partner is entitled to receive 15% of the amount we distribute in excess of $0.1375 per unit, 25% of the amount we distribute in excess of $0.15625 per unit, and 50% of the amount we distribute in excess of $0.1875 per unit. Our partnership agreement contractually limits our distributions to available cash and therefore, undistributed earnings of the ARLP Partnership are not allocated to the IDR holder. In addition, our outstanding unvested awards under our LTIP, SERP and Deferred Compensation Plan contain rights to nonforfeitable distributions and are therefore considered participating securities. As such, we allocate undistributed and distributed earnings to the outstanding awards in our calculation of EPU.

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The following is a reconciliation of net income of ARLP and net income used for calculating EPU and the weighted-average units used in computing EPU for the years ended December 31, 2014, 2013 and 2012, respectively (in thousands, except per unit data):

	Year Ended December 31, 2014	2013	2012
Net income of ARLP	$ 497,229	$ 393,490	$ 335,571
Adjustments:			
Managing general partner priority distributions	(132,449)	(117,995)	(104,168)
General partners 2% equity ownership	(7,325)	(5,554)	(4,669)
General partners special allocation of certain general and administrative expenses	1,500	2,200	2,000
Limited partners interest in Net income of ARLP	358,955	272,141	228,734
Less:			
Distributions to participating securities	(2,956)	(2,362)	(2,095)
Undistributed earnings attributable to participating securities	(2,669)	(1,350)	(922)
Net income of ARLP available to limited partners	$ 353,330	$ 268,429	$ 225,717
Weighted-average limited partner units outstanding Basic and Diluted (1)	74,044	73,904	73,726
Basic and Diluted Net income of ARLP per limited partner unit (1)	$ 4.77	$ 3.63	$ 3.06

(1) Diluted EPU gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive potential units calculated under the treasury stock method if their effect is anti-dilutive. For the year ended December 31, 2014, 2013 and 2012, the combined total of LTIP, SERP and Deferred Compensation Plan units of 798,701, 682,732 and 689,912, respectively, were considered anti-dilutive.

During 2014, 2013 and 2012, our managing general partner made a capital contribution of $1.5 million, $2.2 million and $2.0 million, respectively, to us for certain general and administrative expenses. A special allocation of general and administrative expenses equal to the amount of our managing general partner s contribution was made to them. Net income of ARLP allocated to the limited partners was not burdened by this expense (Note 19).

14. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans Our eligible employees currently participate in a defined contribution profit sharing and savings plan (PSSP) that we sponsor. The PSSP covers substantially all regular full-time employees. PSSP participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. We make matching contributions based on a percent of an employee s eligible compensation and also make an additional nonmatching contribution. Our contribution expense for the PSSP was approximately $21.8 million, $20.4 million and $18.9 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Defined Benefit Plan Eligible employees at certain of our mining operations participate in a defined benefit plan (the Pension Plan) that we sponsor. The Pension Plan is currently closed to new applicants; however, participants in the plan continue to accrue benefits. The benefit formula for the Pension Plan is a fixed-dollar unit based on years of service.

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The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2014 and 2013 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements at December 31, 2014 and 2013, respectively (dollars in thousands):

		2014		2013
Change in benefit obligations:				
Benefit obligations at beginning of year	$	85,662	$	86,468
Service cost		2,174		2,783
Interest cost		4,074		3,640
Actuarial loss (gain)		19,841		(5,479)
Benefits paid		(2,125)		(1,750)
Benefit obligations at end of year		109,626		85,662
Change in plan assets:				
Fair value of plan assets at beginning of year		67,480		55,390
Employer contribution		2,671		2,400
Actual return on plan assets		1,495		11,440
Benefits paid		(2,125)		(1,750)
Fair value of plan assets at end of year		69,521		67,480
Funded status at the end of year	$	(40,105)	$	(18,182)
Amounts recognized in balance sheet:				
Non-current liability	$	(40,105)	$	(18,182)
	$	(40,105)	$	(18,182)
Amounts recognized in accumulated other comprehensive income consists of:				
Net actuarial loss	$	(41,278)	$	(18,230)
Weighted-average assumptions to determine benefit obligations as of December 31,				
Discount rate		3.92%		4.89%
Expected rate of return on plan assets		8.00%		8.00%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,				
Discount rate		4.89%		3.99%
Expected return on plan assets		8.00%		8.00%

The actuarial loss component of the change in benefit obligation in 2014 was primarily attributable to a decrease in the discount rate and the actual rate of return on plan assets compared to December 31, 2013, adoption of newly issued mortality tables reflecting improved life expectancies and updated retirement and withdrawal rate estimates. The actuarial gain component of the change in benefit obligation in 2013 was primarily attributable to an increase in the discount rate and an increase in the actual rate of return on plan assets compared to December 31, 2012, offset in part by an update to future benefit payment estimates.

The expected long-term rate of return assumption is based on broad equity and bond indices, the investment goals and objectives, the target investment allocation and on the long-term historical rates of return for each asset class. The expected long-term rate of return used to determine our pension liability was 8.0% based on the above factors and an asset allocation assumption of 70.0% invested in domestic equity securities with an expected long-term rate of return of 9.9%, 10.0% invested in international equities with an expected long-term rate of return of 5.6% and

20.0% invested in fixed income securities with an expected long-term rate of return of 5.7%. Expected long-term rate of return is based on a 20-year-average annual total return for each investment group.

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The actual return on plan assets was 5.4% and 22.7% for the years ended December 31, 2014 and 2013, respectively.

	2014	2013	2012
		(in thousands)	
Components of net periodic benefit cost:			
Service cost	$ 2,174	$ 2,783	$ 2,682
Interest cost	4,074	3,640	3,246
Expected return on plan assets	(5,475)	(4,446)	(3,882)
Amortization of net loss	773	2,653	1,788
Net periodic benefit cost	$ 1,546	$ 4,630	$ 3,834

	2014	2013
	(in thousands)	
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive income:		
Net actuarial (loss) gain	$ (23,821)	$ 12,472
Reversal of amortization item:		
Net actuarial loss	773	2,653
Total recognized in accumulated other comprehensive (loss) income	(23,048)	15,125
Net periodic benefit cost	(1,546)	(4,630)
Total recognized in net periodic benefit cost and accumulated other comprehensive (loss) income	$ (24,594)	$ 10,495

Estimated future benefit payments as of December 31, 2014 are as follows (in thousands):

Year Ending December 31,	
2015	$ 2,456
2016	2,828
2017	3,222
2018	3,679
2019	4,118
2020-2024	27,416
	$ 43,719

We expect to contribute $3.1 million to the Pension Plan in 2015. The estimated net actuarial loss for the Pension Plan that will be amortized from AOCI into net periodic benefit cost during the 2015 fiscal year is $3.4 million.

As permitted under ASC 715, *Compensation Retirement Benefits*, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the Pension Plan.

The compensation committee of our managing general partner (Compensation Committee) maintains a Funding and Investment Policy Statement (Policy Statement) for the Pension Plan. The Policy Statement provides that the assets of the Pension Plan be invested in a prudent manner based on the stated purpose of the Pension Plan and diversified among a broad range of investments including domestic and international equity securities, domestic fixed income securities and cash equivalents. The Pension Plan allows for the utilization of options in a collar strategy to limit potential exposure to market fluctuations. The investment goal of the Pension Plan is to ensure that the assets provide sufficient resources to meet or exceed the benefit obligations as determined under terms and conditions of the Pension Plan. The Policy Statement provides that the Pension Plan shall be funded by employer contributions in amounts determined in accordance with generally accepted actuarial standards. The investment objectives as established by the Policy Statement are, first, to increase the value of the assets under the Pension Plan and, second, to control the level of risk or volatility of investment returns associated with Pension Plan investments.

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We had unfunded benefit obligations of approximately $40.1 million and $18.2 million at December 31, 2014 and 2013, respectively. In general, increases in benefit obligations will be offset by employer contributions and market returns. However, general market conditions may result in market losses. When the Pension Plan experiences market losses, significant variations in the funded status of the Pension Plan can, and often do, occur. Actuarial methods utilized in determining required future employer contributions take into account the long-term effect of market losses and result in increased future employer contributions, thus offsetting such market losses. Conversely, the long-term effect of market gains will result in decreased future employer contributions. Total account performance is reviewed at least annually, using a dynamic benchmark approach to track investment performance.

The Compensation Committee has selected an investment manager to implement the selection and on-going evaluation of Pension Plan investments. The investments shall be selected from the following assets classes (which may include mutual funds, collective funds, or the direct investment in individual stocks, bonds or cash equivalent investments): (a) money market accounts, (b) U.S. Government bonds, (c) corporate bonds, (d) large, mid, and small capitalization stocks, and (e) international stocks. The Policy Statement provides the following guidelines and limitations, subject to exceptions authorized by the Compensation Committee: (i) the maximum investment in any one stock should not exceed 10.0% of the total stock portfolio, (ii) the maximum investment in any one industry should not exceed 30.0% of the total stock portfolio, and (iii) the average credit quality of the bond portfolio should be at least AA with a maximum amount of non-investment grade debt of 10.0%.

The Policy Statement s asset allocation guidelines are as follows:

	Percentage of Total Portfolio		
	Minimum	**Target**	**Maximum**
Domestic equity securities	50%	70%	90%
Foreign equity securities	0%	10%	20%
Fixed income securities/cash	5%	20%	40%

Domestic equity securities primarily include investments in individual common stocks or registered investment companies that hold positions in companies that are based in the U.S. Foreign equity securities primarily include investments in individual common stocks or registered investment companies that hold positions in companies based outside the U.S. Fixed income securities primarily include individual bonds or registered investment companies that hold positions in U.S. Treasuries, U.S. government obligations, corporate bonds, mortgage-backed securities, and preferred stocks. Short-term market conditions may result in actual asset allocations that fall outside the minimum or maximum guidelines reflected in the Policy Statement.

Asset allocations as of December 31,	**2014**	**2013**
Domestic equity securities	71%	71%
Foreign equity securities	8%	13%
Fixed income securities/cash	21%	16%
	100%	100%

We consider multiple factors in our investment strategy. The following factors have been taken into consideration with respect to the Pension Plan s long-term investment goals and objectives and in the establishment of the Pension Plan s target investment allocation:

- The long-term nature of providing retirement income benefits to Pension Plan participants;
- The projected annual funding requirements necessary to meet the benefit obligations;
- The current level of benefit payments to Pension Plan participants and beneficiaries; and
- Ongoing analysis of economic conditions and investment markets.

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As required by FASB ASC 715, the following information discloses the fair values of our Pension Plan assets, by asset category, for the periods indicated (in thousands):

	December 31, 2014			December 31, 2013		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash and cash equivalents	$ 917	$ -	$ -	$ 1,625	$ -	$ -
Equity securities (a):						
U.S. large-cap growth	19,147	-	-	9,406	-	-
U.S. large-cap value	19,196	-	-	17,731	-	-
U.S. small/mid-cap blend	8,681	-	-	10,512	-	-
International large-cap core	2,934	-	-	4,970	-	-
Fixed income securities:						
U.S. Treasury securities (b)	1,455	-	-	1,426	-	-
Corporate bonds (c)	-	1,802	-	-	1,623	-
Preferred stock	-	61	-	-	107	-
Taxable municipal bonds (c)	-	193	-	-	162	-
International bonds (c)	-	227	-	-	569	-
Equity mutual funds (d):						
U.S. large-cap growth	-	-	-	-	1,446	-
U.S. large-cap value	-	-	-	-	1,398	-
U.S. mid-cap growth	-	2,537	-	-	4,752	-
U.S. small-cap growth	-	-	-	-	1,389	-
U.S. small-cap value	-	-	-	-	1,331	-
International	-	2,856	-	-	-	-
International small/mid-cap blend	-	-	-	-	1,916	-
Emerging Markets	-	-	-	-	1,805	-
Fixed income mutual funds (d):						
Corporate bond	-	4,729	-	-	2,617	-
Mortgage backed-securities	-	1,226	-	-	1,075	-
Short term investment grade bond	-	1,417	-	-	1,009	-
Intermediate investment grade bond	-	1,013	-	-	-	-
High yield bond	-	689	-	-	684	-
International bond	-	296	-	-	207	-
Stock market index options (e):						
Puts	-	111	-	-	46	-
Calls	-	(40)	-	-	(407)	-
Accrued income (f)	-	74	-	-	81	-
Total	$ 52,330	$ 17,191	$ -	$ 45,670	$ 21,810	$ -

(a) Equity securities include investments in publicly traded common stock and preferred stock. Publicly-traded common stocks are traded on a national securities exchange and investments in common and preferred stocks are valued using quoted market prices multiplied by the number of shares owned.

(b) U.S. Treasury securities include agency and treasury debt. These investments are valued using dealer quotes in an active market.

(c) Bonds are valued utilizing a market approach that includes various valuation techniques and sources such as value generation models, broker quotes in active and non-active markets, benchmark yields and securities, reported trades, issuer spreads, and/or other applicable reference data. The corporate bonds and notes category is primarily comprised of U.S. dollar denominated, investment grade securities. Less than 5 percent of the securities have a rating below investment grade.

(d) Mutual funds are valued daily in actively traded markets by an independent custodian for the investment manager. For purposes of calculating the value, portfolio securities and other assets for which market quotes are readily available are valued at market value. Market value is generally determined on a basis of last reported sales prices, or if no sales are reported, based on quotes obtained from a quotation reporting system, established market makers, or pricing services. Investments initially valued in currencies other than the U.S. dollars are converted to the U.S. dollar using exchange rates obtained from pricing services.

(e) Options are valued utilizing a market approach that includes various valuation techniques and sources such as value generation models, broker quotes in active and non-active markets, reported trades, issuer spreads, and/or other applicable reference data.

(f) Accrued income represents dividends declared, but not received, on equity securities owned at December 31, 2014.

Pension Plan assets for which the fair value is based on quoted prices in active markets for identical assets are considered to be valued with Level 1 inputs in the fair value hierarchy. Pension Plan assets for which the fair value is based on quoted prices for similar instruments in active markets or quoted prices for identical or similar instruments in markets that are not active are considered to be valued with Level 2 inputs in the fair value hierarchy.

15. COMPENSATION PLANS

We have the LTIP for certain of our employees and officers of our managing general partner and its affiliates who perform services for us. The LTIP awards are of non-vested phantom or notional units, which upon satisfaction of vesting requirements, entitle the LTIP participant to receive ARLP common units. Annual grant levels and vesting

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provisions for designated participants are recommended by our President and Chief Executive Officer, subject to the review and approval of the Compensation Committee.

On January 22, 2014 the Compensation Committee determined that the vesting requirements for the 2011 grants of 202,742 restricted units (which was net of 14,090 forfeitures) had been satisfied as of January 1, 2014. As a result of this vesting, on February 14, 2014, we issued 128,610 unrestricted common units to LTIP participants. The remaining units were settled in cash to satisfy the tax withholding obligations for the LTIP participants. On January 26, 2015, the Compensation Committee determined that the vesting requirements for the 2012 grants of 202,778 restricted units (which was net of 11,450 forfeitures) had been satisfied as of January 1, 2015. As a result of this vesting, on February 11, 2015, we issued 128,150 unrestricted common units to the LTIP participants. The remaining units were settled in cash to satisfy the individual statutory minimum tax obligations of the LTIP participants.

On January 26, 2015, the Compensation Committee authorized additional grants of 314,019 restricted units, of which 302,555 units were granted. During the years ended December 31, 2014 and 2013, we issued grants of 356,154 units and 293,450 units, respectively. Grants issued during the year ending December 31, 2015 vest on January 1, 2018. Grants issued during the year ended December 31, 2014 vest on January 1, 2017. Grants issued during the year ended December 31, 2013 vest on January 1, 2016. Vesting of all grants is subject to the satisfaction of certain financial tests, which management currently believes is probable. As of December 31, 2014, 20,492 of these outstanding LTIP grants have been forfeited. After consideration of the January 1, 2015 vesting and subsequent issuance of 128,150 common units, 4.0 million units remain available for issuance in the future, assuming that all grants issued in 2013 and 2014 and currently outstanding are settled with common units, without reduction for tax withholding, and no future forfeitures occur.

For the years ended December 31, 2014, 2013 and 2012, our LTIP expense was $9.6 million, $7.4 million and $6.4 million, respectively. The total obligation associated with the LTIP as of December 31, 2014 and 2013 was $17.9 million and $14.7 million, respectively, and is included in limited partners capital in our consolidated balance sheets.

The fair value of the 2014, 2013 and 2012 grants is based upon the intrinsic value at the date of grant, which was $40.72, $31.51 and $38.86 per restricted unit, respectively, on a weighted-average basis. We expect to settle the non-vested LTIP grants by delivery of ARLP common units, except for the portion of the grants that will satisfy the minimum statutory tax withholding requirements. As provided under the distribution equivalent rights provision of the LTIP, all non-vested grants include contingent rights to receive quarterly cash distributions in an amount equal to the cash distribution we make to unitholders during the vesting period.

A summary of non-vested LTIP grants as of and for the year ended December 31, 2014 is as follows:

Non-vested grants at January 1, 2014	695,532
Granted	356,154
Vested	(202,742)
Forfeited	(5,604)
Non-vested grants at December 31, 2014	843,340

As of December 31, 2014, there was $12.5 million in total unrecognized compensation expense related to the non-vested LTIP grants that are expected to vest. That expense is expected to be recognized over a weighted-average period of 1.5 years. As of December 31, 2014, the intrinsic value of the non-vested LTIP grants was $36.3 million.

SERP and Directors Deferred Compensation Plan

We utilize the SERP to provide deferred compensation benefits for certain officers and key employees. All allocations made to participants under the SERP are made in the form of phantom ARLP units. The SERP is administered by the Compensation Committee.

Our directors participate in the Deferred Compensation Plan. Pursuant to the Deferred Compensation Plan, for amounts deferred either automatically or at the election of the director, a notional account is established and credited with notional common units of ARLP, described in the plan as phantom units.

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

For the years ended December 31, 2014 and 2013, SERP and Deferred Compensation Plan participant notional account balances were credited with a total of 27,577 and 33,738 phantom units, respectively, and the fair value of these phantom units was $44.56 and $35.48, respectively, on a weighted-average basis. Total SERP and Deferred Compensation Plan expense was approximately $1.2 million, $1.2 million and $0.8 million for the years ended December 31, 2014, 2013 and 2012, respectively.

As of December 31, 2014, there were 368,981 total phantom units outstanding under the SERP and Deferred Compensation Plan and the total intrinsic value of the SERP and Deferred Compensation Plan phantom units was $15.9 million. As of December 31, 2014 and 2013, the total obligation associated with the SERP and Deferred Compensation Plan was $12.6 million and $11.5 million, respectively, and is included in the partners capital-limited partners line item in our consolidated balance sheets.

16. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31, 2014		2013 (in thousands)		2012	
Cash Paid For:						
Interest	$	34,005	$	35,362	$	35,833
Non-Cash Activity:						
Accounts payable for purchase of property, plant and equipment	$	15,654	$	17,924	$	20,972
Market value of common units vested in Long-Term Incentive Plan and Deferred Compensation Plan before minimum statutory tax withholding requirements	$	8,417	$	8,583	$	11,070
Acquisition of business:						
Fair value of assets assumed	$	-	$	-	$	126,639
Cash paid		-		-		(100,000)
Fair value of liabilities assumed	$	-	$	-	$	26,639
Disposition of property, plant and equipment:						
Net change in assets	$	846	$	-	$	-
Book value of liabilities transferred		(5,246)		-		-
Gain recognized	$	(4,400)	$	-	$	-
Liabilities assumed in asset acquisition	$	6,042	$	-	$	-

17. ASSET RETIREMENT OBLIGATIONS

The majority of our operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations, among other requirements, require restoration of property in accordance with specified standards and an approved reclamation plan. We account for our asset retirement obligations in accordance with FASB ASC 410, *Asset Retirement and Environmental Obligations*, which requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred. We have estimated the costs and timing of future asset retirement obligations escalated for inflation, then discounted and recorded at the present value of those estimates. Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and are typically renewable on a yearly basis. As of December 31, 2014 and 2013, we had approximately $142.3 million and $88.7 million, respectively, in surety bonds outstanding to secure the performance of our reclamation obligations.

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The impact of discounting our estimated cash flows resulted in reducing the accrual for asset retirement obligations by $88.8 million and $76.5 million at December 31, 2014 and 2013, respectively. Estimated payments of asset retirement obligations as of December 31, 2014 are as follows (in thousands):

Year Ending December 31,		
2015	$	2,055
2016		2,127
2017		1,914
2018		1,964
2019		698
Thereafter		173,135
Aggregate undiscounted asset retirement obligations		181,893
Effect of discounting		(88,753)
Total asset retirement obligations		93,140
Less: current portion		(2,055)
Asset retirement obligations	$	91,085

The following table presents the activity affecting the asset retirement and mine closing liability (in thousands):

	Year ended December 31,			
		2014		**2013**
Beginning balance	$	82,898	$	84,836
Accretion expense		2,730		3,004
Payments		(1,134)		(2,242)
Assumption of existing liability		6,042		-
Disposition		(5,246)		-
Allocation of liability associated with acquisitions, mine development and change in assumptions		7,850		(2,700)
Ending balance	$	93,140	$	82,898

For the year ended December 31, 2014, the allocation of liability associated with acquisition, mine development and change in assumptions is a net increase of $7.9 million. This increase was attributable to increased size of refuse sites primarily at our Onton, Gibson South, Tunnel Ridge, Dotiki and River View operations, offset in part by the net impact of overall general changes in inflation and discount rates, current estimates of the costs and scope of remaining reclamation work, reclamation work completed and fluctuations in other projected mine life estimates. The increase in the total liability was also attributed to the acquisition of additional property with certain existing reclamation liabilities (Note 3), offset in part by the sale of property associated with the Pontiki mine (Note 4).

For the year ended December 31, 2013, the allocation of liability associated with acquisition, mine development and change in assumptions is a net decrease of $2.7 million, which was primarily attributable to extension of mine life estimate at our Mettiki operation as a result of the acquisition of additional reserves (Note 3), offset by increased refuse site reclamation disturbances primarily at our Tunnel Ridge, Warrior and Pattiki operations and new disturbances associated with the construction of the Gibson South mine, as well as the net impact of overall general changes in inflation and discount rates, current estimates of the costs and scope of remaining reclamation work, reclamation work completed and fluctuation in other projected mine life estimates.

18. ACCRUED WORKERS COMPENSATION AND PNEUMOCONIOSIS BENEFITS

Certain of our mine operating entities are liable under state statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay pneumoconiosis, or black lung, benefits to eligible employees and former employees and their dependents. In addition, we are liable for workers compensation benefits for traumatic injuries. Both black lung and traumatic claims are covered through our self-insured programs.

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Our black lung benefits liability is calculated using the service cost method that considers the calculation of the actuarial present value of the estimated black lung obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates. Actuarial gains or losses are amortized over the remaining service period of active miners.

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on our actuarial estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates. The discount rate used to calculate the estimated present value of future obligations for black lung was 3.82%, 4.69% and 3.78% at December 31, 2014, 2013 and 2012, respectively, and for workers compensation was 3.41%, 4.11% and 3.22% at December 31, 2014, 2013 and 2012, respectively.

The black lung and workers' compensation expense consists of the following components for the year ended December 31, 2014, 2013 and 2012 (in thousands):

	2014	2013	2012
Black lung benefits:			
Service cost	$ 3,424	$ 3,810	$ 3,758
Interest cost	2,262	2,253	2,372
Net amortization	(1,051)	670	776
Total black lung	4,635	6,733	6,906
Workers' compensation expense (benefit)	7,776	(110)	17,572
Total expense	$ 12,411	$ 6,623	$ 24,478

The following is a reconciliation of the changes in the black lung benefit obligation recognized in AOCI for the years ended December 31, 2014 and 2013 (in thousands):

	2014	2013	2012
Net actuarial (loss) gain	$ (2,029)	$ 16,750	$ 2,156
Reversal of amortization item:			
Net actuarial (gain) loss	(1,051)	670	776
Total recognized in accumulated other comprehensive income (loss)	$ (3,080)	$ 17,420	$ 2,932

The following is a reconciliation of the changes in workers' compensation liability (including current and long-term liability balances) at December 31, 2014 and 2013 (in thousands):

	2014	2013

Beginning balance	$	62,909	$	77,046
Accruals		14,978		18,544
Payments		(10,563)		(10,639)
Interest accretion		2,585		2,481
Valuation gain		(12,352)		(24,523)
Ending balance	$	57,557	$	62,909

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The valuation gain component of the change in benefit obligation in 2014 was primarily attributable to favorable changes in claims development, offset partially by a decrease in the discount rate used to calculate the estimated present value of future obligations. The 2013 valuation gain was primarily attributable to favorable reserve adjustments for claims incurred in prior years and an increase in the discount rate used to calculate the estimated present value of future obligations.

The following is a reconciliation of the changes in black lung benefit obligations at December 31, 2014 and 2013 (in thousands):

	2014	2013
Benefit obligations at beginning of year	$ 49,560	$ 60,991
Service cost	3,424	3,810
Interest cost	2,262	2,253
Actuarial loss (gain)	2,029	(16,750)
Benefits and expenses paid	(889)	(744)
Benefit obligations at end of year	$ 56,386	$ 49,560

	2014	2013	2012
Amount recognized in accumulated other comprehensive income consist of:			
Net actuarial (gain) loss	$ (5,431)	$ (8,511)	$ 8,908

The actuarial loss component of the change in benefit obligations in 2014 was primarily attributable to a decrease in the discount rate used to calculate the estimated present value of future obligations as well as unfavorable changes in claims development and disability incident rate assumptions. The 2013 valuation gain was primarily attributable to favorable reserve adjustments for claims incurred in prior years, as well as an increase in the discount rate used to calculate the estimated present value of future obligations.

Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for black lung and workers' compensation benefits at December 31, 2014 and 2013 (in thousands):

	2014	2013
Black lung claims	$ 56,386	$ 49,560
Workers' compensation claims	57,557	62,909
Total obligations	113,943	112,469
Less current portion	(8,868)	(9,065)
Non-current obligations	$ 105,075	$ 103,404

Both the black lung and workers' compensation obligations were unfunded at December 31, 2014 and 2013.

As of December 31, 2014 and 2013, we had $79.3 million and $86.3 million, respectively, in surety bonds and letters of credit outstanding to secure workers' compensation obligations.

19. RELATED-PARTY TRANSACTIONS

The board of directors of our managing general partner (Board of Directors) and its conflicts committee (Conflicts Committee) review our related-party transactions that involve a potential conflict of interest between a general partner and ARLP or its subsidiaries or another partner to determine that such transactions reflect market-clearing terms and conditions customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to us and our limited partners.

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Administrative Services On April 1, 2010, effective January 1, 2010, ARLP entered into an Amended and Restated Administrative Services Agreement (the Administrative Services Agreement) with our managing general partner, our Intermediate Partnership, AHGP and its general partner AGP, and Alliance Resource Holdings II, Inc. (ARH II), the indirect parent of SGP. 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 to our managing general partner, AHGP, AGP, ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these affiliates as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under the Administrative Services Agreement of $0.4 million during each of the years ended December 31, 2014, 2013 and 2012 from AHGP and $0.1 million during each of the years ended December 31, 2014, 2013 and 2012 from ARH II, respectively.

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, director fees and expenses, management s salaries and related benefits (including incentive compensation), and accounting, budgeting, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers' compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $0.8 million, $0.8 million and $1.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Managing General Partner Contributions During December 2014, 2013 and 2012, an affiliated entity controlled by Mr. Craft contributed $1.5 million, $2.2 million and $2.0 million, respectively, to AHGP for the purpose of funding certain of our general and administrative expenses. Upon AHGP s receipt of each contribution, it contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made special allocations to our managing general partner of certain general and administrative expenses equal to its contributions (Note 13).

White Oak On September 22, 2011, we entered into a series of transactions with White Oak and related entities to support development of a longwall mining operation. The initial longwall system commenced operation in late October 2014. The transactions feature several components, including an equity investment containing certain distribution and liquidation preferences, the acquisition and lease-back of certain reserves and surface rights, a coal handling and services agreement and a loan for surface facilities. The transactions are expected to generate equity distributions and have begun generating royalties and throughput revenues. See Note 12 for further information on these related party transactions.

In addition to the agreements discussed above, White Oak also has agreements with our subsidiaries for the purchase of various services and products, including for coal handling services provided by our Mt. Vernon transloading facility. For the years ended December 31, 2014, 2013 and 2012, we recorded revenues of $3.9 million, $2.4 million and $1.0 million, respectively, for services and products provided by Mt. Vernon and Matrix Design to White Oak, which are included in Other sales and operating revenues on our consolidated statements of income. For information on royalties and throughput revenues, see Note 12.

SGP Land, LLC On March 1, 2012, JC Air, LLC (JC Air), a wholly owned subsidiary of our special general partner, was acquired by and merged into our subsidiary, ASI. JC Air s sole assets were two airplanes, one of which was previously subject to a time-sharing agreement between SGP Land, a subsidiary of SGP, and us. In consideration for this merger, we paid SGP approximately $8.0 million cash at closing.

ASI has agreements with JC Land LLC (JC Land), an entity owned by Mr. Craft, SGP Land and Mr. Craft, providing for the use of ASI s aircraft. JC Land, SGP and Mr. Craft paid us $0.1 million for aircraft usage in each of the years ended December 31, 2014, 2013 and 2012, as a result of these agreements. In addition, Alliance Coal has an agreement with JC Land providing for the use of JC Land s aircraft by Alliance Coal. As a result of this agreement, we paid JC Land $0.2 million, $0.3 million and $0.1 million for aircraft usage in the years ended December 31, 2014, 2013 and 2012, respectively.

Effective August 1, 2013, Alliance Coal entered into an expense reimbursement agreement with JC Land regarding pilots hired by Alliance Coal to operate aircraft owned by ASI and JC Land. In accordance with the expense

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reimbursement agreement, JC Land reimburses Alliance Coal for a portion of the compensation expense for its pilots. JC Land paid us $0.2 million and $0.1 million for the years ended December 31, 2014 and 2013, respectively, pursuant to this agreement.

We reimbursed SGP Land $0.3 million for the year ended December 31, 2012, in accordance with the provisions of the replaced time-sharing agreement, which ended on March 1, 2012 upon the merger of JC Air into ASI, as discussed above.

In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty of $0.3 million until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $0.9 million, $0.3 million and $0.3 million for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014, all advanced minimum royalties paid under the lease have been recouped.

SGP In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease with SGP. Under the terms of the lease, Tunnel Ridge has paid and will continue to pay an annual minimum royalty of $3.0 million until the earlier of January 1, 2033 or the exhaustion of the mineable and merchantable leased coal. Tunnel Ridge paid advance minimum royalties of $3.0 million during each of the years ended December 31, 2014, 2013 and 2012. As of December 31, 2014, $10.7 million of advance minimum royalties paid under the lease is available for recoupment and management expects that it will be recouped against future production.

Tunnel Ridge also controls surface land and other tangible assets under a separate lease agreement with SGP. Under the terms of the lease agreement, Tunnel Ridge has paid and will continue to pay SGP an annual lease payment of $0.2 million. The lease agreement had an initial term of four years, which may be extended to match the term of the coal lease. Lease expense was $0.2 million for each of the years ended December 31, 2014, 2013 and 2012.

We have a noncancelable lease arrangement for the Gibson North mine s coal preparation plant and ancillary facilities with SGP. The lease requires monthly payments of approximately $50,000 and extends through January 2017. Based on the lease arrangement, it is considered a capital lease. Lease payments for each of the years ended December 31, 2014, 2013 and 2012 were $0.6 million.

WKY CoalPlay On November 17, 2014 (the CoalPlay Formation Date), SGP Land and the Craft Companies entered into a limited liability company agreement to form WKY CoalPlay. WKY CoalPlay was formed, in part, to purchase and lease coal reserves. WKY CoalPlay is managed by an entity controlled by an officer of ARH who is also a director of ARH II, the indirect parent of SGP, an employee of SGP Land and a trustee of the irrevocable trusts owning the Craft Companies.

In December 2014, WKY CoalPlay acquired approximately 86.6 million tons of proven and probable high-sulfur coal reserves in western Kentucky and southern Indiana through its purchase of two indirect subsidiaries of CONSOL Energy Inc. for $57.2 million. In December 2014, WKY CoalPlay s subsidiaries leased 72.3 million tons of the acquired reserves to us and, as partial consideration for entering the leases, conveyed the remaining 14.3 million tons of its acquired reserves to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a mine plan. The leases have initial terms ranging from 7 to 20 years and provide for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $6.2 million. All annual minimum royalty payments are recoupable against earned royalty payments. WKY CoalPlay also granted to us an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the leases. We paid WKY CoalPlay $6.2 million in January 2015 for the initial annual minimum royalty payment.

In December 2014, WKY CoalPlay acquired approximately 54.1 million tons of proven and probable high-sulfur coal reserves in western Kentucky through its purchase of a subsidiary of Midwest for $29.6 million. In conjunction with this acquisition, WKY CoalPlay s subsidiary leased 22.6 million tons of the acquired reserves to us and, as partial consideration for entering the lease, conveyed the remaining 31.5 million tons to us. The conveyed reserves have minimal value as a result of uncertainty regarding their inclusion in a mine plan. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $2.5 million. All annual minimum royalty payments are recoupable against earned royalty payments. WKY CoalPlay also granted to us an option to acquire the leased reserves at any time during a three-year period

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beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the lease. We paid WKY CoalPlay $2.5 million in January 2015 for the initial annual minimum royalty payment.

In February 2015, WKY CoalPlay acquired approximately 39.1 million tons of proven and probable high-sulfur owned coal reserves located in Henderson and Union Counties, Kentucky from Central States, a subsidiary of Patriot, for $25.0 million and in turn leased those reserves to us. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $2.1 million. All annual minimum royalty payments are recoupable against earned royalty payments. An option was also granted to us to acquire the leased reserves at any time during a three-year period beginning in February 2018 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the lease. We paid WKY CoalPlay $2.1 million in February 2015 for the initial annual minimum royalty payment.

Based on the guidance in FASB ASC 810, we concluded that WKY CoalPlay is a VIE because exercise of the options noted above is not within the control of the equity holders and, if it occurs, could potentially limit the expected residual return to the owners of WKY CoalPlay. We do not have any economic or governance rights related to WKY CoalPlay and our options that provide us with a variable interest in WKY CoalPlay s reserve assets do not give us any rights that constitute power to direct the primary activities that most significantly impact WKY CoalPlay s economic performance. SGP Land has the sole ability to replace the manager of WKY CoalPlay at its discretion and therefore has power to direct the activities of WKY CoalPlay. Consequently, we concluded that SGP Land is the primary beneficiary of WKY CoalPlay.

Total future minimum royalties from 2015 through 2019 under agreements with SGP Land, SGP and WKY CoalPlay as discussed above are expected to be the following (in thousands):

Year Ending December 31,		
2015	$	14,118
2016		13,857
2017		13,818
2018		13,818
2019		13,818

Cavalier Minerals On November 10, 2014, Cavalier Minerals contributed $7.4 million in return for a limited partner interest in AllDale Minerals, an entity created to purchase oil and gas mineral interests in various geographical locations within producing basins in the continental United States. Additional contributions totaling $4.2 million were made to AllDale Minerals prior to December 31, 2014 with the remaining commitment of $37.4 million expected to be paid over the next two to four years. At December 31, 2014, Cavalier Minerals limited partner interest in AllDale Minerals was 71.7%. AllDale Minerals is managed and controlled by its general partner, AllDale Minerals Management. AllDale Minerals Management is owned by four members, consisting of three parties unrelated to us or our affiliates and Bluegrass Minerals, which is owned by an officer of ARH. See Note 11 and 12 for further information.

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20. COMMITMENTS AND CONTINGENCIES

Commitments We lease buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. We also have a noncancelable lease with SGP (Note 19) and a noncancelable lease for equipment under a capital lease obligation. Future minimum lease payments are as follows (in thousands):

Year Ending December 31,	Capital Lease	Other Operating Leases: Affiliate	Other Operating Leases: Others	Other Operating Leases: Total
2015	$ 2,054	$ 240	$ 1,416	$ 1,656
2016	2,065	-	1,416	1,416
2017	1,850	-	1,009	1,009
2018	1,818	-	650	650
2019	1,930	-	-	-
Thereafter	11,934	-	-	-
Total future minimum lease payments	$ 21,651	$ 240	$ 4,491	$ 4,731
Less: amount representing interest	(4,722)			
Present value of future minimum lease payments	16,929			
Less: current portion	(1,305)			
Long-term capital lease obligation	$ 15,624			

Rental expense (including rental expense incurred under operating lease agreements) was $4.7 million, $5.1 million and $5.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Contractual Commitments In connection with planned capital projects, we have contractual commitments of approximately $50.8 million at December 31, 2014. As of December 31, 2014, we had no material commitments to purchase coal from external production sources in 2015.

On September 22, 2011, we entered into a series of transactions with White Oak and related entities to support development of a longwall mining operation. The initial longwall system commenced operation in late October 2014. At December 31, 2014, we have funded $390.0 million related to these transactions and, inclusive of this funding, we have committed to fund to White Oak a total of approximately $395.5 million to $415.5 million from the Transaction Date through December 31, 2015. Additional equity investments of $39.8 million and $45.9 million were contributed by another White Oak owner in 2014 and 2013, respectively. On the Transaction Date, we also entered into a coal handling and preparation agreement, pursuant to which we constructed and are operating a preparation plant and other surface facilities. We plan to utilize existing cash balances, future cash flows from operations, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity to fund our commitments to the White Oak project. For more information on the White Oak transactions, please read Note 12.

On November 10, 2014, Cavalier Minerals purchased equity interests in AllDale Minerals, an entity created to purchase oil and gas mineral interests in various geographic locations within producing basins in the continental United States. Cavalier Minerals initial investment funding to AllDale Minerals at the Cavalier Formation Date was $7.4 million and it has funded an additional $4.2 million between the Cavalier Formation Date and December 31, 2014. Cavalier Minerals has a remaining commitment to AllDale Minerals of $37.4 million at December 31, 2014, which it expects to fund over the next two to four years. Alliance Minerals committed funding of $48.0 million to Cavalier Minerals, of which $11.5 million was funded as of December 31, 2014 and the balance we expect to fund over the same period. Bluegrass Minerals also provides funding to Cavalier Minerals. We plan to utilize existing cash balances, future cash flows from operations, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity to fund Alliance Minerals commitments to Cavalier Minerals, which in turn principally uses this funding to fund its commitments to AllDale Minerals. For more information on these transactions, please read Note 11 and 12.

General Litigation Various lawsuits, claims and regulatory proceedings incidental to our business are pending against the ARLP Partnership. We record an accrual for a potential loss related to these matters when, in management s opinion, such loss is probable and reasonably estimable. Based on known facts and circumstances, we believe the ultimate outcome of these outstanding lawsuits, claims and regulatory proceedings will not have a material adverse effect on our financial condition, results of operations or liquidity. However, if the results of these matters were different from management s current opinion and in amounts greater than our accruals, then they could have a material adverse effect.

Other Effective October 1, 2014, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market at a reduced cost. The maximum limit in the commercial property program is $100.0 million per occurrence, excluding a $1.5 million deductible for property damage, a 90 or 120 day waiting period for underground business interruption depending on the mining complex and an additional $10.0 million overall aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

21. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

We have significant long-term coal supply agreements, some of which contain prospective price adjustment provisions designed to reflect changes in market conditions, labor and other production costs and, in the infrequent circumstance when the coal is sold other than free on board the mine, changes in transportation rates. Total revenues from major customers, including transportation revenues, which are at least ten percent of total revenues, are as follows (in thousands):

		Year Ended December 31,		
	Segment (Note 22)	**2014**	**2013**	**2012**
Customer A	Illinois Basin	$ 301,191	$ 319,932	$ 336,560
Customer B	Illinois Basin	276,094	263,582	243,339

Trade accounts receivable from these customers totaled approximately $43.5 million and $45.8 million at December 31, 2014 and 2013, respectively. Our bad debt experience has historically been insignificant. Financial conditions of our customers could result in a material change to our bad debt expense in future periods. The coal supply agreements with our significant customers expire in 2016.

22. SEGMENT INFORMATION

We operate in the eastern U.S. as a producer and marketer of coal to major utilities and industrial users. We aggregate multiple operating segments into four reportable segments: the Illinois Basin, Appalachia, White Oak and Other and Corporate. The first two reportable segments correspond to major coal producing regions in the eastern U.S. Similar economic characteristics for our operating segments within each of these two reportable segments generally include coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues. The White Oak reportable segment includes our activities associated with the White Oak Mine No. 1, which commenced initial longwall operation in late October 2014.

The Illinois Basin reportable segment is comprised of multiple operating segments, including Webster County Coal s Dotiki mining complex, Gibson County Coal s mining complex, which includes the Gibson North mine and Gibson South mine, Hopkins County Coal s mining complex, which includes the Elk Creek mine and the Fies property, White County Coal s Pattiki mining complex, Warrior s mining complex, Sebree Mining s mining complex, which includes the Onton mine, and River View s mining complex. In April 2014, production began at the Gibson South mine. The Elk Creek mine is currently expected to cease production in early 2016. Illinois Basin reserves and other assets increased as a result of multiple acquisitions in 2014 and 2015 as discussed in Note 3.

The Appalachia reportable segment is comprised of multiple operating segments, including the Mettiki mining complex, the Tunnel Ridge mining complex, the MC Mining mining complex and the Penn Ridge property. The Mettiki mining complex includes Mettiki Coal (WV) s Mountain View mine, Mettiki Coal s preparation plant and a small third-party mining operation, which has been idled since July 2013. In May 2012, longwall production began at the Tunnel Ridge mine. We are in the process of permitting the Penn Ridge property for future mine development.

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The White Oak reportable segment is comprised of two operating segments, WOR Processing and WOR Properties. WOR Processing includes both the surface operations at White Oak and the equity investment in White Oak. WOR Properties owns coal reserves acquired from White Oak under lease-back arrangements (Note 12).

The Other and Corporate segment includes marketing and administrative expenses, ASI and its subsidiary, Matrix Design, Alliance Design (collectively, Matrix Design and Alliance Design are referred to as the Matrix Group) and ASI s ownership of aircraft (Note 19), the Mt. Vernon dock activities, coal brokerage activity, our equity investment in MAC, certain activities of Alliance Resource Properties, the Pontiki mining complex, which ceased operations in November 2013 and sold most of its assets in May 2014, Wildcat Insurance, Alliance Minerals, and its affiliate, Cavalier Minerals (Note 11), which holds an equity investment in AllDale Minerals (Note 12), and AROP Funding (Note 7).

As a result of the cessation of operations at the Pontiki mine in November 2013, we evaluated the ongoing management of our mining operations and coal sales efforts to ensure that resources were appropriately allocated to maximize our overall results. Based on this evaluation, we have realigned the management of our operating and marketing teams and changed our reportable segment presentation to reflect this realignment. Due to the change in our reportable segment presentation in 2014, certain reclassifications of 2013 and 2012 segment information have been made to conform to the 2014 presentation. These reclassifications include changes to the Appalachia segment and Other and Corporate segment as well as eliminations.

Reportable segment results as of and for the years ended December 31, 2014, 2013 and 2012 are presented below.

	Illinois Basin	Appalachia	White Oak	Other and Corporate	Elimination (1)	Consolidated
			(in thousands)			
Reportable segment results as of and for the year ended December 31, 2014 were as follows:						
Total revenues (2)	$ 1,626,450	$ 630,452	$ 21,244	$ 34,090	$ (11,515)	$ 2,300,721
Segment Adjusted EBITDA Expense (3)	992,045	364,689	7,983	25,487	(8,396)	1,381,808
Segment Adjusted EBITDA (4)(5)	620,111	254,037	(3,384)	8,599	(3,119)	876,244
Total assets (6)	1,174,141	604,352	407,138	258,424	(158,996)	2,285,059
Capital expenditures (7)	237,953	56,840	5,214	11,462	-	311,469
Reportable segment results as of and for the year ended December 31, 2013 were as follows:						
Total revenues (2)	$ 1,629,089	$ 493,689	$ 2,194	$ 98,272	$ (17,683)	$ 2,205,561
Segment Adjusted EBITDA Expense (3)	951,686	375,923	2,112	86,864	(17,683)	1,398,902
Segment Adjusted EBITDA (4)(5)	657,404	105,123	(25,229)	12,278	-	749,576
Total assets (6)	1,077,231	594,466	317,361	133,915	(1,075)	2,121,898
Capital expenditures (7)	232,676	72,926	40,185	8,636	-	354,423
Reportable segment results as of and for the year ended December 31, 2012 were as follows:						
Total revenues (2)	$ 1,499,976	$ 444,993	$ -	$ 105,860	$ (16,528)	$ 2,034,301
Segment Adjusted EBITDA Expense (3)	894,769	361,560	(1,347)	100,329	(16,528)	1,338,783
Segment Adjusted EBITDA (4) (5)	593,054	73,553	(13,987)	6,214	-	658,834

Total assets (6)	1,042,719	603,088	226,714	84,550	(1,099)	1,955,972
Capital expenditures (7)	219,029	137,336	85,671	17,196	-	459,232

(1) The elimination column represents the elimination of intercompany transactions and is primarily comprised of sales from the Matrix Group to our mining operations, coal sales and purchases between mining operations within different segments (2013 only), sales of receivables to AROP Funding and insurance premiums paid to Wildcat Insurance (2014 only).

(2) Revenues included in the Other and Corporate column are primarily attributable to the Matrix Group revenues, Mt. Vernon transloading revenues, administrative service revenues from affiliates, brokerage sales and Pontiki s coal sales revenue (2013 only). Also included in the Other and Corporate column are Wildcat Insurance revenues, which are eliminated upon consolidation.

(3) Segment Adjusted EBITDA Expense includes operating expenses, outside coal purchases and other income. Transportation expenses are excluded as these expenses are passed through to our customers and consequently we do not realize any gain or loss on transportation revenues. We review Segment Adjusted EBITDA Expense per ton for cost trends.

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The following is a reconciliation of consolidated Segment Adjusted EBITDA Expense to operating expenses (excluding depreciation, depletion and amortization) (in thousands):

	Year Ended December 31, 2014	2013	2012
Segment Adjusted EBITDA Expense	$ 1,381,808	$ 1,398,902	$ 1,338,783
Outside coal purchases	(14)	(2,030)	(38,607)
Other income	1,566	1,891	3,115
Operating expenses (excluding depreciation, depletion and amortization)	$ 1,383,360	$ 1,398,763	$ 1,303,291

(4) Segment Adjusted EBITDA is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization, asset impairment charge and general and administrative expenses. Management therefore is able to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments. Consolidated Segment Adjusted EBITDA is reconciled to net income below (in thousands):

	Year Ended December 31, 2014	2013	2012
Consolidated Segment Adjusted EBITDA	$ 876,244	$ 749,576	$ 658,834
General and administrative	(72,552)	(63,697)	(58,737)
Depreciation, depletion and amortization	(274,566)	(264,911)	(218,122)
Asset impairment charge	-	-	(19,031)
Interest expense, net	(31,913)	(26,082)	(28,455)
Income tax (expense) benefit	-	(1,396)	1,082
Net income	$ 497,213	$ 393,490	$ 335,571

(5) Includes equity in income (loss) of affiliates for the years ended December 31, 2014, 2013 and 2012 of $(16.6) million, $(25.3) million and $(15.3) million, respectively, for the White Oak segment and $(3) thousand, $0.9 million and $0.7 million, respectively, for the Other and Corporate segment.

(6) Total assets at December 31, 2014, 2013 and 2012 include investments in affiliate of $211.7 million, $128.7 million and $86.8 million, respectively, for the White Oak segment and $12.9 million, $1.7 million and $1.7 million, respectively, for the Other and Corporate segment.

(7) Capital expenditures shown above include funding to White Oak of $4.1 million, $25.3 million and $34.6 million, for the years ended December 31, 2014, 2013 and 2012, respectively, for the acquisition and development of coal reserves from White Oak (Note 12), which is described as Payments to affiliate for acquisition and development of coal reserves in our consolidated statements of cash flow. Capital expenditures shown above exclude the Green River acquisition in April 2012 (Note 3) and purchase of coal supply agreements from Patriot in December 2014 (Note 3).

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23. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our consolidated quarterly operating results in 2014 and 2013 is as follows (in thousands, except unit and per unit data):

	Quarter Ended			
	March 31, 2014	June 30, 2014 (1)	September 30, 2014	December 31, 2014 (1)
Revenues	$ 542,038	$ 598,562	$ 569,328	$ 590,793
Income from operations	129,513	153,034	127,513	134,148
Income before income taxes	115,904	137,653	119,978	123,678
Net income of ARLP	115,904	137,653	119,978	123,694
Basic and diluted net income of ARLP per limited partner unit	$ 1.10	$ 1.37	$ 1.13	$ 1.18
Weighted-average number of units outstanding basic and diluted	73,994,866	74,060,634	74,060,634	74,060,634

	Quarter Ended			
	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013 (1)
Revenues	$ 548,055	$ 553,571	$ 537,229	$ 566,706
Income from operations	112,316	115,569	98,002	117,631
Income before income taxes	102,239	104,183	86,468	101,996
Net income of ARLP	102,937	104,074	87,186	99,293
Basic and diluted net income of ARLP per limited partner unit	$ 0.98	$ 0.98	$ 0.75	$ 0.93
Weighted-average number of units outstanding basic and diluted	73,838,004	73,926,108	73,926,108	73,926,108

(1) The comparability of our December 31, 2013 quarterly results to other quarters presented was affected by a $12.9 million decrease in our workers compensation liability, excluding discount rate changes, due to the completion of our annual actuarial study, which reflected favorable development in our disability emergence patterns and claims estimates (Note 18). The comparability of our June 30, 2014 quarterly results to other quarters presented was affected by $7.0 million insurance settlement related to adverse geological events at the Onton mine in the third quarter of 2013 and a gain of $4.4 million recognized on the sale of Pontiki s assets.

24. SUBSEQUENT EVENTS

Other than those events described in Notes 3, 9, 12, 15 and 19, there were no subsequent events.

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SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

	Balance At Beginning of Year	Additions Charged to Income	Deductions	Balance At End of Year
		(in thousands)		
2014				
Allowance for doubtful accounts	$ -	$ -	$ -	$ -
2013				
Allowance for doubtful accounts	$ -	$ -	$ -	$ -
2012				
Allowance for doubtful accounts	$ -	$ -	$ -	$ -

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. We maintain controls and procedures designed to provide reasonable assurance that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Exchange Act) as of December 31, 2014. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures are effective as of December 31, 2014.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the ARLP Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based, in part, upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

Management s Annual Report on Internal Control over Financial Reporting. Management of the ARLP Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-

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15(f) under the Exchange Act. The ARLP Partnership s internal control over financial reporting is designed to provide reasonable assurance to our management and Board of Directors of our managing general partner regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the ARLP Partnership s assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are complemented by a staff of competent business process owners and an internal auditor supported by competent and qualified external resources used to assist in testing the operating effectiveness of the ARLP Partnership s internal control over financial reporting. Management concluded that the design and operations of our internal controls over financial reporting at December 31, 2014 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the ARLP Partnership.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework (2013)*. Based on its assessment, management concluded that, as of December 31, 2014, the ARLP Partnership s internal control over financial reporting was effective based on those criteria, and management believes that we have no material internal control weaknesses in our financial reporting process.

Ernst & Young LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014, as stated in their report that is included herein.

Changes in Internal Controls Over Financial Reporting. There has been no change in our internal controls over financial reporting (as defined in Rule 13a-15(f) or Rule 15d-15(f) of the Exchange Act) in the three months ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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Report of Independent Registered Public Accounting Firm

The Board of Directors of Alliance Resource Management GP, LLC

and the Partners of Alliance Resource Partners, L.P.

We have audited Alliance Resource Partners, L.P. s (the Partnership) internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013) (the COSO criteria). The Partnership s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Alliance Resource Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and partners capital for each of the three years in the period ended December 31, 2014 and our report dated February 27, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2015

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ITEM 9B. OTHER INFORMATION

None.

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PART III

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

As is commonly the case with publicly traded limited partnerships, we are managed and operated by our managing general partner. The following table shows information for executive officers and members of the Board of Directors as of the date of the filing of this Annual Report on Form 10-K. Executive officers and directors are elected until death, resignation, retirement, disqualification, or removal.

Name	Age	Position With Our Managing General Partner
Joseph W. Craft III	64	President, Chief Executive Officer and Director
Brian L. Cantrell	55	Senior Vice President and Chief Financial Officer
R. Eberley Davis	57	Senior Vice President, General Counsel and Secretary
Robert G. Sachse	66	Executive Vice President Marketing
Charles R. Wesley	60	Executive Vice President and Director
Thomas M. Wynne	58	Senior Vice President and Chief Operating Officer
Michael J. Hall	70	Director and Member of Audit* and Compensation Committees
John P. Neafsey	75	Chairman of the Board and Member of Compensation and Conflicts* Committees
John H. Robinson	64	Director and Member of Audit, Compensation* and Conflicts Committees
Wilson M. Torrence	73	Director and Member of Audit, Compensation and Conflicts Committees

* Indicates Chairman of Committee

Joseph W. Craft III has been President, Chief Executive Officer and a Director since August 1999 and has indirect majority ownership of our managing general partner. Mr. Craft also serves as President, Chief Executive Officer and Chairman of the Board of Directors of AGP, the general partner of AHGP. Previously Mr. Craft served as President of MAPCO Coal Inc. since 1986. During that period, he also was Senior Vice President of MAPCO Inc. and had previously been that company s General Counsel and Chief Financial Officer. He is a former Chairman of the National Coal Council, a Board Member of the National Mining Association, and a Director of American Coalition for Clean Coal Electricity, and has been a Director of BOK Financial Corporation (NASDAQ: BOKF) since April of 2007 and became chairman of its compensation committee in 2014. Mr. Craft holds a Bachelor of Science degree in Accounting and a Juris Doctorate degree from the University of Kentucky. Mr. Craft also is a graduate of the Senior Executive Program of the Alfred P. Sloan School of Management at Massachusetts Institute of Technology. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Craft should serve as a Director include his long history of significant involvement in the coal industry, his demonstrated business acumen and his exceptional leadership of the Partnership since its inception.

Brian L. Cantrell has been Senior Vice President and Chief Financial Officer since October 2003. Mr. Cantrell also serves as Senior Vice President and Chief Financial Officer of AGP, the general partner of AHGP. Prior to his current position, Mr. Cantrell was President of AFN Communications, LLC from November 2001 to October 2003 where he had previously served as Executive Vice President and Chief Financial Officer after joining AFN in September 2000. Mr. Cantrell s previous positions include Chief Financial Officer, Treasurer and Director with Brighton Energy, LLC from August 1997 to September 2000; Vice President Finance of KCS Medallion Resources, Inc.; and Vice President Finance, Secretary and Treasurer of Intercoast Oil and Gas Company. Mr. Cantrell is a Certified Public Accountant and holds a Masters of Accountancy and Bachelor of Accountancy from the University of Oklahoma.

R. Eberley Davis has been Senior Vice President, General Counsel and Secretary since February 2007. Mr. Davis also serves as Senior Vice President, General Counsel and Secretary of AGP, the general partner of AHGP. From 2003 to February 2007, Mr. Davis practiced law in the Lexington, Kentucky office of Stoll Keenon Ogden PLLC. Prior to joining Stoll Keenon Ogden, Mr. Davis was Vice President, General Counsel and Secretary of Massey Energy Company for one year. Mr. Davis also served in various positions, including Vice President and General Counsel, for Lodestar Energy, Inc. from 1993 to 2002. Mr. Davis is an alumnus of the University of Kentucky, where he received a Bachelor of Arts degree in Economics and his Juris Doctorate degree. He also holds a Masters of Business Administration degree from the University of Kentucky. Mr. Davis is a Trustee of the Energy and Mineral Law Foundation, and a member of the American and Kentucky Bar Associations.

Robert G. Sachse has been Executive Vice President since August 2000. Effective November 1, 2006, Mr. Sachse assumed responsibility for our coal marketing, sales and transportation functions. Mr. Sachse was also Vice Chairman of our managing general partner from August 2000 to January 2007. Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO merged with The Williams Companies. Following the merger, Mr. Sachse had a two year non-compete consulting agreement with The Williams Companies. Mr. Sachse held various positions while with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree in Business Administration from Trinity University and a Juris Doctorate degree from the University of Tulsa.

Charles R. Wesley has been a Director since January 2009 and Executive Vice President since March 2009. Mr. Wesley has served in a variety of capacities since joining the company in 1974, including as Senior Vice President Operations from August 1996 through February 2009. Mr. Wesley is a former Chairman of the Board of Directors of the Kentucky Coal Association and also has served the industry as past President of the West Kentucky Mining Institute and National Mine Rescue Association Post 11, and as a director of the Kentucky Mining Institute. Mr. Wesley holds a Bachelor of Science degree in Mining Engineering from the University of Kentucky. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Wesley should serve as a Director include his long history of significant involvement in the coal industry, his successful leadership of the Partnership s operations, and his knowledge and technical expertise in all aspects of producing and marketing coal.

Thomas M. Wynne has been Senior Vice President and Chief Operating Officer since March 2009. Mr. Wynne joined the company in 1981 as a mining engineer and has held a variety of positions with the company prior to his appointment in July 1998 as Vice President Operations. Mr. Wynne has served the coal industry on the National Executive Committee for National Mine Rescue and previously as a member of the Coal Safety Committee for the National Mining Association. Mr. Wynne holds a Bachelor of Science degree in Mining Engineering from the University of Pittsburgh and a Masters of Business Administration degree from West Virginia University.

Michael J. Hall became a Director in March 2003. Mr. Hall is Chairman of the Audit Committee and a member of the Compensation Committee. Since March 2006, Mr. Hall has also been a Director and Chairman of the audit committee of AGP, the general partner of AHGP. Mr. Hall is Chairman of the Board of Directors of Matrix Service Company (Matrix) (NASDAQ: MTRX). Previously, Mr. Hall served as President and Chief Executive Officer of Matrix from March 2005 until he retired in November 2006. Mr. Hall also served as Vice President Finance and Chief Financial Officer, Secretary and Treasurer of Matrix from September 1998 to May 2004. Mr. Hall became a Director of Matrix in October 1998, and was elected Chairman of its Board in November 2006. Matrix is a company that provides general industrial construction and repair and maintenance services principally to the petroleum, petrochemical, power, bulk storage terminal, pipeline and industrial gas industries. Prior to working for Matrix, Mr. Hall was Vice President and Chief Financial Officer of Pexco Holdings, Inc., Vice President Finance and Chief Financial Officer for Worldwide Sports & Recreation, Inc., an affiliated company of Pexco, and worked for T.D. Williamson, Inc., as Senior Vice President, Chief Financial and Administrative Officer, and Director of Operations Europe, Africa and Middle East Region. Mr. Hall was a member and Chairman of the Board of Directors of Integrated Electrical Services, Inc. (NASDAQ: IESC) and served in that capacity from May 2006 to February 2011, and was a member of its audit, compensation and nominating/governance committees. Mr. Hall served as Chairman of the Board of Directors of American Performance Funds, was a member of its audit and nominating committees and served as independent trustee from July 1990 to May 2008. Mr. Hall holds a Bachelor of Science degree in Accounting from Boston College and a Masters of Business Administration from Stanford University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Hall should serve as a Director include his long history of service in senior corporate leadership positions, his significant knowledge of the energy industry, and his extensive expertise and experience in financial reporting matters gained from his service as

Chief Financial Officer of a public company.

John P. Neafsey has served as Chairman of the Board of Directors since June 1996. Mr. Neafsey is also Chairman of the Conflicts Committee and a member of the Compensation Committee. Mr. Neafsey is President of JN Associates,

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an investment consulting firm formed in 1993. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and as a Director since its founding in 1983. Positions that Mr. Neafsey held during a 23-year career at The Sun Company include Director; Executive Vice President responsible for Canadian operations, Sun Coal Company and Helios Capital Corporation; Chief Financial Officer; and other executive and director positions with numerous subsidiary companies. He is or has been active in a number of organizations, including the following: former Director and Chairman of the audit committee for The West Pharmaceutical Services Company and former Chairman and a member of the audit and compensation committees of Constar, Inc., former Chairman and member of the audit and compensation committees of NES Rentals, Inc., Trustee Emeritus and Presidential Counselor, Cornell University, and Overseer of Cornell-Weill Medical Center. Mr. Neafsey holds a Bachelor of Science degree in Engineering and a Masters of Business Administration degree from Cornell University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Neafsey should serve as a Director include his extensive service in senior corporate leadership positions in both the energy and financial services industries, and his technical expertise, knowledge and experience with financial markets.

John H. Robinson became a Director in December 1999. Mr. Robinson is Chairman of the Compensation Committee and a member of the Audit and Conflicts Committees. Mr. Robinson is Chairman of Hamilton Ventures, LLC. From 2003 to 2004, he was Chairman of EPC Global, Ltd., an engineering staffing company. From 2000 to 2002, he was Executive Director of Amey plc, a British business process outsourcing company. Mr. Robinson served as Vice Chairman of Black & Veatch, Inc. from 1998 to 2000. He began his career at Black & Veatch in 1973 and was a General Partner and Managing Partner prior to becoming Vice Chairman when the firm incorporated. Mr. Robinson is a Director of Coeur Mining Corporation and a member of its executive and audit committees and chairman of its compensation committee, and he is a Director of the Federal Home Loan Bank of Des Moines, also serving on its mission, member and housing committee and as chairman of its compensation committee. Mr. Robinson is also a Director of Olsson Associates. He holds Bachelor and Masters of Science degrees in Engineering from the University of Kansas and is a graduate of the Owner-President-Management Program at the Harvard Business School. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Robinson should serve as a Director include his significant experience in the engineering and consulting industries, his extensive service in senior corporate leadership positions in both industries and his familiarity with financial matters.

Wilson M. Torrence became a Director in January 2007. Mr. Torrence is a member of the Audit, Compensation and Conflicts Committees. Mr. Torrence retired from Fluor Corporation in 2006 as a Senior Vice President of Project Development and Investments and since that time has performed investment and business consulting services for various clients. Mr. Torrence was employed at Fluor from 1989 to 2006 where, among other roles, he was responsible for the global Project Investment and Structured Finance Group and served as Chairman of Fluor s Investment Committee. In that position, Mr. Torrence had executive responsibility for Fluor s global activities in developing and arranging third-party financing for some of Fluor s clients′ construction projects. Prior to joining Fluor in 1989, Mr. Torrence was President and CEO of Combustion Engineering Corporation s Waste to Energy Division and, during that time, also served as Chairman of the Institute of Resource Recovery, a Washington-based industry advocacy organization. Mr. Torrence began his career at Mobil Oil Corporation, where he held several executive positions, including Assistant Treasurer of Mobil s International Marketing and Refining Division and Chief Financial and Planning Officer of Mobil Land Development Company. From October 2006 to March 2007, Mr. Torrence served as Chief Financial Officer and as a Director of Cleantech America, LLC, a private company involved in development of central station solar generating plants. Mr. Torrence holds Bachelor and Masters degrees in Business Administration from Virginia Tech University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Torrence should serve as a Director include his extensive experience in the construction and energy businesses, his senior corporate finance-related and other leadership positions and his participation in numerous financing transactions.

Board of Directors

The leadership structure of our Board of Directors has been consistent since the Partnership s inception. Our President and Chief Executive Officer is a member of our Board of Directors but is not its Chairman, and our Chairman is an independent Director. We believe this structure is appropriate for the Partnership because it allows for leadership of the Board of Directors that is independent of management, enhancing the effectiveness of the Board of Directors oversight.

Our Board of Directors generally administers its risk oversight function through the board as a whole. Our President and Chief Executive Officer, who reports to the Board of Directors, and the other executives named above, who report to our President and Chief Executive Officer, have day-to-day risk management responsibilities. At the Board of Director s

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request, each of these executives attends the meetings of our Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations and our safety performance, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, management provides periodic reports of the Partnership s financial and operational performance to each member of the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership s internal auditor, who reports directly to the Audit Committee, and reviews the Partnership s contingencies, significant transactions and subsequent events, among other matters, with management and our independent auditors.

The Board of Directors has selected as director nominees individuals with experience, skills and qualifications relevant to the business of the Partnership, such as experience in energy or related industries or with financial markets, expertise in mining, engineering or finance, and a history of service in senior leadership positions. The Board of Directors has not established a formal process for identifying director nominees, nor does it have a formal policy regarding consideration of diversity in identifying director nominees, but has endeavored to assemble a diverse group of individuals with the qualities and attributes required to provide effective oversight of the Partnership.

Audit Committee

The Audit Committee comprises three non-employee members of the Board of Directors (currently, Mr. Hall, Mr. Robinson and Mr. Torrence). After reviewing the qualifications of the current members of the Audit Committee, and any relationships they may have with us that might affect their independence, the Board of Directors has determined that all current Audit Committee members are independent as that concept is defined in Section 10A of the Exchange Act, all current Audit Committee members are independent as that concept is defined in the applicable rules of NASDAQ Stock Market, LLC, all current Audit Committee members are financially literate, and Mr. Hall qualifies as an audit committee financial expert under the applicable rules promulgated pursuant to the Exchange Act.

Report of the Audit Committee

The Audit Committee oversees our financial reporting process on behalf of the Board of Directors. Management has primary responsibility for the financial statements and the reporting process including the systems of internal controls. The Audit Committee has responsibility for the appointment, compensation and oversight of the work of our independent registered public accounting firm and assists the Board of Directors by conducting its own review of our:

- filings with the SEC pursuant to the Securities Act of 1933 (the Securities Act) and the Exchange Act (i.e., Forms 10-K, 10-Q, and 8-K);
- press releases and other communications by us to the public concerning earnings, financial condition and results of operations, including changes in distribution policies or practices affecting the holders of our units, if such review is not undertaken by the Board of Directors;
- systems of internal controls regarding finance and accounting that management and the Board of Directors have established; and
- auditing, accounting and financial reporting processes generally.

In fulfilling its oversight and other responsibilities, the Audit Committee met eight times during 2014. The Audit Committee s activities included, but were not limited to: (a) selecting the independent registered public accounting firm, (b) meeting periodically in executive session with the independent registered public accounting firm, (c) reviewing the Quarterly Reports on Form 10-Q for the three months ended March 31, June 30, and September 30, 2014, (d) performing a self-assessment of the committee, (e) reviewing the Audit Committee charter, and (f) reviewing the overall scope, plans and findings of our internal auditor. Based on the results of the annual self-assessment, the Audit Committee believes that it satisfied the requirements of its charter. The Audit Committee also reviewed and discussed with management and the independent registered public accounting firm this Annual Report on Form 10-K, including the audited financial statements.

Our independent registered public accounting firm, Ernst & Young LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with GAAP. The Audit Committee reviewed with Ernst & Young

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LLP its judgment as to the quality, not just the acceptability, of our accounting principles and such other matters as are required to be discussed with the Audit Committee under generally accepted auditing standards.

The Audit Committee discussed with Ernst & Young LLP the matters required to be discussed by the Statement of Auditing Standards (SAS) 114, *The Auditor s Communication with Those Charged with Governance*, as may be modified or supplemented. The Audit Committee received written disclosures and the letter from Ernst & Young LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant s communication with the Audit Committee regarding independence, and has discussed with Ernst & Young LLP its independence from management and the ARLP Partnership.

Based on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2014 for filing with the SEC.

Members of the Audit Committee:

Michael J. Hall, Chairman

John H. Robinson

Wilson M. Torrence

Code of Ethics

We have adopted a code of ethics with which our President and Chief Executive Officer and our senior financial officers (including our principal financial officer and our principal accounting officer or controller) are expected to comply. The code of ethics is publicly available on our website under Investor Relations at www.arlp.com and is available in print without charge to any unitholder who requests it. Such requests should be directed to Investor Relations at (918) 295-7674. If any substantive amendments are made to the code of ethics or if there is a grant of a waiver, including any implicit waiver, from a provision of the code to our President and Chief Executive Officer, Chief Financial Officer, or Controller, we will disclose the nature of such amendment or waiver on our website or in a report on Form 8-K.

Communications with the Board

Unitholders or other interested parties can contact any director or committee of the Board of Directors by writing to them c/o Senior Vice President, General Counsel and Secretary, P. O. Box 22027, Tulsa, Oklahoma 74121-2027. Comments or complaints relating to our accounting, internal accounting controls or auditing matters will also be referred to members of the Audit Committee. The Audit Committee has procedures for (a) receipt, retention and treatment of complaints received by us regarding accounting, internal accounting controls, or auditing matters and (b) the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms they file. Based upon a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that during 2014 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a).

Reimbursement of Expenses of our Managing General Partner and its Affiliates

Our managing general partner does not receive any management fee or other compensation in connection with its management of us. Our managing general partner is reimbursed by us for all expenses incurred on our behalf. Please see Item 13. Certain Relationships and Related Transactions, and Director Independence *Administrative Services*.

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ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Introduction

The Compensation Committee oversees the compensation of our managing general partner s executive officers, including the President and Chief Executive Officer, our principal executive officer, the Senior Vice President and Chief Financial Officer, our principal financial officer, and the three most highly compensated executive officers in 2014, each of whom is named in the Summary Compensation Table (collectively, our Named Executive Officers). Our Named Executive Officers are employees of our operating subsidiary, Alliance Coal. Certain of our Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, Alliance Coal is reimbursed for such services by those related parties pursuant to an administrative services agreement. Please see Item 13 Certain Relationships and Related Transactions, and Director Independence *Administrative Services.* We do not have employment agreements with any of our Named Executive Officers.

Compensation Objectives and Philosophy

The compensation of our Named Executive Officers is designed to achieve two key objectives: (i) provide a competitive compensation opportunity to allow us to recruit and retain key management talent, and (ii) motivate and reward the executive officers for creating sustainable, capital-efficient growth in available cash to maximize our distributions to our unitholders. In making decisions regarding executive compensation, the Compensation Committee reviews current compensation levels of other companies in the coal industry and other peers, considers our President and Chief Executive Officer s assessment of each of the other executives, and uses its discretion to determine an appropriate total compensation package of base salary and short-term and long-term incentives. The Compensation Committee intends for each executive officer s total compensation to be competitive in the marketplace and to effectively motivate the officer. Based upon its review of our overall executive compensation program, the Compensation Committee believes the program is appropriately applied to our managing general partner s executive officers and is necessary to attract and retain the executive officers who are essential to our continued development and success, to compensate those executive officers for their contributions and to enhance unitholder value. Moreover, the Compensation Committee believes the total compensation opportunities provided to our managing general partner s executive officers create alignment with our long-term interests and those of our unitholders. As a result, we do not maintain unit ownership requirements for our Named Executive Officers.

Setting Executive Compensation

Role of the Compensation Committee

The Compensation Committee discharges the Board of Directors responsibilities relating to our managing general partner s executive compensation program. The Compensation Committee oversees our compensation and benefit plans and policies, administers our incentive bonus and equity participation plans, and reviews and approves annually all compensation decisions relating to our Named Executive Officers.

The Compensation Committee is empowered by the Board of Directors and by the Compensation Committee s charter to make all decisions regarding compensation for our Named Executive Officers without ratification or other action by the Board of Directors. The Compensation Committee has authority to secure services for executive compensation matters, legal advice, or other expert services, both from within and outside the company. While the Compensation Committee is empowered to delegate all or a portion of its duties to a subcommittee, it has not done so.

The Compensation Committee comprises all of our directors who have been determined to be independent by the Board of Directors in accordance with applicable NASDAQ Stock Market, LLC and SEC regulations, presently Messrs. Robinson, Hall, Neafsey and Torrence.

Role of Executive Officers

Each year, the President and Chief Executive Officer submits recommendations to the Compensation Committee for adjustments to the salary, bonuses and long-term equity incentive awards payable to our Named Executive Officers, excluding himself. The President and Chief Executive Officer bases his recommendations on his assessment of each executive s performance, experience, demonstrated leadership, job knowledge and management skills. The Compensation

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Committee considers the recommendations of the President and Chief Executive Officer as one factor in making compensation decisions regarding our Named Executive Officers. Historically, and in 2014, the Compensation Committee and the President and Chief Executive Officer have been substantially aligned on decisions regarding compensation of the Named Executive Officers. As executive officers are promoted or hired during the year, the President and Chief Executive Officer makes compensation recommendations to the Compensation Committee and works closely with the Compensation Committee to ensure that all compensation arrangements for executive officers are consistent with our compensation philosophy and are approved by the Compensation Committee. At the direction of the Compensation Committee, the President and Chief Executive Officer and the Senior Vice President, General Counsel and Secretary attend certain meetings of the Compensation Committee.

Use of Peer Group Comparisons

The Compensation Committee believes that it is important to review and compare our performance with that of peer companies in the coal industry, and reviews the composition of the peer group annually. The peer group for 2014 included CONSOL Energy Inc., Arch Coal, Inc., Alpha Natural Resources Inc., James River Coal Company, Walter Energy, Inc., Oxford Resource Partners, LP, Natural Resource Partners L.P. and Rhino Resource Partners LP. In assessing the competitiveness of our executive compensation program for 2014, the Compensation Committee, with the assistance of the President and Chief Executive Officer, collected and analyzed peer group proxy information and developed a comparative analysis of base salaries, short-term incentives, total cash compensation, long-term incentives and total direct compensation. The Compensation Committee uses the peer group data as a point of reference for comparative purposes, but it is not the determinative factor for the compensation of our Named Executive Officers. The Compensation Committee exercises discretion in determining the nature and extent of the use of comparative pay data.

Consideration of Equity Ownership

Mr. Craft, the President and Chief Executive Officer, is evaluated and treated differently with respect to compensation than our other Named Executive Officers. Mr. Craft and related entities own significant equity positions in AHGP, which owns MGP, the IDR in ARLP and, as of December 31, 2014, 42.0% of ARLP s outstanding common units. Because of these ownership positions, the interests of Mr. Craft are directly aligned with those of our unitholders. Mr. Craft has not received an increase in base salary since 2002 and has not received a bonus under our short-term incentive plan (STIP) or any grants of LTIP awards since 2005.

Compensation Components

Overview

The principal components of compensation for our Named Executive Officers include:

- base salary;

- annual cash incentive bonus awards under the STIP; and

- awards of restricted units under the LTIP.

The relative amount of each component is not based on any formula, but rather is based on the recommendation of the President and Chief Executive Officer, subject to the discretion of the Compensation Committee to make any modifications it deems appropriate.

Each of our Named Executive Officers also receives supplemental retirement benefits through the SERP. In addition, all executive officers are entitled to customary benefits available to our employees generally, including group medical, dental, and life insurance and participation in our profit sharing and savings plan (PSSP). Our PSSP is a defined contribution plan and includes an employer matching contribution of 75% on the first 3% of eligible compensation contributed by the employee, an employer non-matching contribution of 0.75% of eligible compensation, and an employer supplemental contribution of 5% of eligible compensation. The PSSP provides an additional means of attracting and retaining qualified employees by providing tax-advantaged opportunities for employees to save for retirement.

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Base Salary

When reviewing base salaries, the Compensation Committee s policy is to consider the individual s experience, tenure and performance, the individual s level of responsibility, the position s complexity and its importance to us in relation to other executive positions, our financial performance, and competitive pay practices. The Compensation Committee also considers comparative compensation data of companies in our peer group and the recommendation of the President and Chief Executive Officer of our managing general partner. Base salaries are reviewed annually to ensure continuing consistency with market levels, and adjustments to base salaries are made as needed to reflect movement in the competitive market as well as individual performance.

Annual Cash Incentive Bonus Awards

The STIP is designed to assist us in attracting, retaining and motivating qualified personnel by rewarding management, including our Named Executive Officers, and selected other salaried employees with cash awards for our achievement of an annual financial performance target. The annual performance target is recommended by the President and Chief Executive Officer and approved by the Compensation Committee, typically in January of each year. The performance measure is subject to equitable adjustment in the sole discretion of the Compensation Committee to reflect the occurrence of any significant events during the year.

The performance target historically has been EBITDA-based, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the operating results of the core mining business. (EBITDA is defined as net income of ARLP before net interest expense, income taxes, depreciation, depletion and amortization and net income attributable to noncontrolling interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target, and it increases in relationship to our EBITDA, as adjusted, exceeding the minimum threshold. The Compensation Committee may determine satisfactory results and adjust the size of the pay-out pool in its sole discretion. In 2014, the Compensation Committee approved a minimum financial performance target of $693.4 million in EBITDA from current operations, normalized by excluding any charges for unit-based and directors compensation and affiliate contributions, if any, and we exceeded the minimum target.

Awards to our Named Executive Officers each year are determined by and in the discretion of the Compensation Committee. However, the Compensation Committee does not establish individual target payout amounts for the Named Executive Officers STIP awards or otherwise communicate with the Named Executive Officers regarding their STIP awards or the payout amounts thereunder until the individual STIP awards are paid. As it does when reviewing base salaries, in determining individual awards under the STIP the Compensation Committee considers its assessment of the individual s performance, our financial performance, comparative compensation data of companies in our peer group and the recommendation of the President and Chief Executive Officer. The compensation expense associated with STIP awards is recognized in the year earned, with the cash awards payable in the first quarter of the following calendar year. Termination of employment of an executive officer for any reason prior to payment of a cash award will result in forfeiture of any right to the award, unless and to the extent waived by the Compensation Committee in its discretion.

The performance measure for the STIP in 2015 will be EBITDA for current operations plus net cash flow from our White Oak investments, and excluding charges for unit-based and directors compensation and affiliate contributions, if any. As discussed above, the Compensation Committee may, in its discretion, make equitable adjustments to the performance criteria under the STIP and adjust the amount of the aggregate pay-out. The Compensation Committee believes the STIP performance criteria for 2015 will be reasonably difficult to achieve and therefore support our key compensation objectives discussed above.

Equity Awards under the LTIP

Equity compensation pursuant to the LTIP is a key component of our executive compensation program. Our LTIP is sponsored by Alliance Coal. Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. The Compensation Committee has authority to determine the participants to whom restricted units are granted, the number of restricted units to be granted to each such participant, and the conditions under which the restricted units may become vested, including the duration of any vesting period. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our managing general partner s President and Chief Executive Officer, subject to review and approval by the Compensation Committee. Grant levels are intended to support the objectives of the comprehensive compensation package described

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above. The LTIP grants provide our Named Executive Officers with the opportunity to achieve a meaningful ownership stake in the Partnership, thereby assuring that their interests are aligned with our success. Even though Mr. Craft has not been granted an award under the LTIP since 2005, the Compensation Committee believes Mr. Craft s interests are directly aligned with the interests of our unitholders as a result of his ownership positions. There is no formula for determining the size of awards to any individual recipient and, as it does when reviewing base salaries and individual STIP payments, the Compensation Committee considers its assessment of the individual s performance, our financial performance, compensation levels at peer companies in the coal industry and the recommendation of the President and Chief Executive Officer. Amounts realized from prior grants, including amounts realized due to changes in the value of our common units, are not considered in setting grant levels or other compensation for our Named Executive Officers.

Restricted Units. Restricted units granted under the LTIP are phantom or notional units that upon vesting entitle the participant to receive an ARLP common unit. Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. However, if a grantee s employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will be automatically forfeited, unless the Compensation Committee, in its sole discretion, determines otherwise. The number of units actually distributed upon satisfaction of the applicable vesting requirements is reduced to cover the minimum statutory income tax withholding requirement for each individual participant based upon the fair market value of the common units as of the date of distribution. All grants of restricted units under the LTIP include the contingent right to receive quarterly cash distributions in an amount equal to the cash distributions we make to unitholders during the vesting period.

The performance target applicable to restricted unit awards under the LTIP is based on a normalized EBITDA measure, with that measure typically being the same as the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. We typically issue grants under the LTIP at the beginning of each year, with the exceptions of new employees who begin employment with us at some other time and job promotions that may occur at some other time. The compensation expense associated with LTIP grants is recognized over the vesting period in accordance with FASB ASC 718, *Compensation Stock Compensation*.

Our managing general partner s policy is to grant restricted units pursuant to the LTIP to serve as a means of incentive compensation for performance. Therefore, no consideration will be payable by the LTIP participants upon receipt of the common units. Common units to be delivered upon the vesting of restricted units may be common units we already own, common units we acquire in the open market or from any other person, newly issued common units, or any combination of the foregoing. If we issue new common units upon payment of the restricted units instead of purchasing them, the total number of common units outstanding will increase.

Grants for 2014 under the LTIP, made January 22, 2014, will cliff vest on January 1, 2017 provided we achieve a target level of aggregate EBITDA for current operations, excluding any charges for unit-based and directors compensation and affiliate contributions, if any, for the period January 1, 2014 through December 31, 2016. The most recent grants under the LTIP, made January 26, 2015, will cliff vest on January 1, 2018 provided we achieve a target level of aggregate EBITDA for current operations plus net cash flow from our White Oak investments, and excluding any charges for unit-based and directors compensation and affiliate contributions, if any, for the period January 1, 2015 through December 31, 2017. The LTIP provides the Compensation Committee with discretion to determine the conditions for vesting (as well as all other terms and conditions) associated with any award under the plan, and to amend any of those conditions so long as an amendment does not materially reduce the benefit to the participant. The Compensation Committee believes the performance-related vesting conditions of all outstanding awards under the LTIP will be reasonably difficult to satisfy and therefore support our key compensation objectives discussed above.

Unit Options. We have not made any grants of unit options. The Compensation Committee, in the future, may decide to make unit option grants to employees and directors on terms determined by the Compensation Committee.

Grant Timing. The Compensation Committee does not time, nor has the Compensation Committee in the past timed, the grant of LTIP awards in coordination with the release of material non-public information. Instead, LTIP awards are granted only at the time or times dictated by our normal compensation process as developed by the Compensation Committee.

Effect of a Change in Control. Upon a change in control as defined in the LTIP, all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. Please see Item 11. Executive Compensation *Potential Payments Upon a Termination or Change of Control*.

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Amendments and Termination. Our Board of Directors or the Compensation Committee may, in its discretion, terminate the LTIP at any time with respect to any common units for which a grant has not previously been made. Except as required by the rules of the exchange on which the common units may be listed at that time, our Board of Directors or the Compensation Committee may alter or amend the LTIP in any manner from time to time; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the affected participant. In addition, our Board of Directors or the Compensation Committee may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward our employees.

Supplemental Executive Retirement Plan

We maintain the SERP to help attract and motivate key employees, including our Named Executive Officers. The SERP is sponsored by Alliance Coal. Participation in the SERP aligns the interest of each Named Executive Officer with the interests of our unitholders because all allocations made to participants under the SERP are made in the form of notional common units of ARLP, defined in the SERP as phantom units. The Compensation Committee approves the SERP participants and their percentage allocations, and can amend or terminate the SERP at any time. All of our Named Executive Officers currently participate in the SERP.

Under the terms of the SERP, a participant is entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of the participant s base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant s cumulative notional phantom unit account balance earns the equivalent of common unit distributions, which are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant s termination from employment in ARLP common units equal to the number of phantom units then credited to the participant s account, less the number of units required to satisfy our tax withholding obligations. A participant in the SERP is not entitled to an allocation for the year in which his termination from employment occurs, except as described below.

A participant in the SERP, including any of our Named Executive Officers, is entitled to receive an allocation under the SERP for the year in which his employment is terminated only if such termination results from one of the following events:

(1) the participant s employment is terminated other than for cause ;

(2) the participant terminates employment for good reason ;

(3) a change of control of us or our managing general partner occurs and, as a result, the participant s employment is terminated (whether voluntary or involuntary);

(4) death of the participant;

(5) the participant attains (or has attained) retirement age of 65 years; or

(6) the participant incurs a total and permanent disability, which shall be deemed to occur if the participant is eligible to receive benefits under the terms of the long-term disability program we maintain.

This allocation for the year in which a participant s termination occurs shall equal the participant s eligible compensation for such year (including any severance amount, if applicable) multiplied by his percentage allocation under the SERP, reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year.

Other Compensation-Related Matters

Trading in Derivatives

It is our managing general partner s policy that directors and all officers, including the Named Executive Officers, may not purchase or sell options on ARLP s common units.

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Tax Deductibility of Compensation

The deduction limitations imposed under Section 162(m) of the Internal Revenue Code do not apply to compensation paid to our Named Executive Officers because we are a limited partnership and not a corporation within the meaning of Section 162(m).

Perquisites and Personal Benefits

The Partnership provides a limited amount of perquisites and personal benefits to the Named Executive Officers in keeping with the Compensation Committee s objectives to provide competitive compensation to motivate and reward executive officers for creating sustainable, capital-efficient growth in available cash. These perquisites and personal benefits typically include amounts for items such as tax preparation fees and social club dues, and are reviewed annually by the Compensation Committee.

Compensation Committee Report

The Compensation Committee has submitted the following report for inclusion in this Annual Report on Form 10-K:

Our Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K with management. Based on our Compensation Committee s review of and the discussions with management with respect to the Compensation Discussion and Analysis, our Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

The foregoing report is provided by the following directors, who constitute all the members of the Compensation Committee:

Members of the Compensation Committee:

John H. Robinson, Chairman

Michael J. Hall

John P. Neafsey

Wilson M. Torrence

Notwithstanding anything to the contrary set forth in any of our previous filings under the Securities Act or the Exchange Act, that incorporate future filings, including this Annual Report on Form 10-K, in whole or in part, the foregoing Compensation Committee Report shall not be deemed to be filed with the SEC or incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that we specifically incorporate it by reference.

The comparative unit amounts and unit prices reflected in the following tables have been adjusted for the two-for-one unit split completed on June 16, 2014.

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Summary Compensation Table

Name and Principal Position	Year	Salary (2)	Bonus (1)	Unit Awards (3)	Option Awards (1)	Non-Equity Incentive Plan Compensation (4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (1)	All Other Compensation (5)	Total
Joseph W. Craft III,	2014	$ 334,828	$ -	$ -	$ -	$ -	$ -	$ 409,828	$ 744,656
	2013	334,828	-	-	-	-	-	372,326	707,154
President, Chief Executive Officer and Director	2012	334,828	-	-	-	-	-	302,867	637,695
Brian L. Cantrell,	2014	282,096	-	607,401	-	412,500	-	87,592	1,389,589
	2013	275,000	-	451,664	-	370,000	-	65,901	1,162,565
Senior Vice President - Chief Financial Officer	2012	259,773	-	370,388	-	287,000	-	64,426	981,587
R. Eberley Davis	2014	321,827	-	775,808	-	465,000	-	102,304	1,664,939
	2013	310,000	-	494,707	-	415,000	-	84,432	1,304,139
Senior Vice President, General Counsel and Secretary	2012	291,002	-	500,903	-	300,000	-	81,901	1,173,806
Robert G. Sachse,	2014	320,250	-	880,992	-	511,500	-	136,627	1,849,369
	2013	310,000	-	572,411	-	465,000	-	124,128	1,471,539
Executive Vice President-Marketing	2012	299,398	-	461,547	-	300,000	-	108,079	1,169,024
Thomas M. Wynne,	2014	370,827	-	856,968	-	538,500	-	106,226	1,872,521
	2013	359,000	-	651,186	-	400,000	-	74,427	1,484,613
Senior Vice President and Chief Operating Officer	2012	335,164	-	510,937	-	300,000	-	70,390	1,216,491

(1) Column is not applicable.

(2) Certain of our Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, the base salary of those executive officers is reimbursed to Alliance Coal by those related parties pursuant to an administrative services agreement. Please see Item 1. Business Employees *Administrative Services Agreement*. In 2014, 2013 and 2012, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 4% for Mr. Cantrell and 8% for Mr. Davis.

(3) The Unit Awards represent the aggregate grant date fair value of equity awards granted (computed in accordance with FASB ASC 718) to each Named Executive Officer under the LTIP in the respective year. Please see Item 11. Compensation Discussion and Analysis Compensation Program Components *Equity Awards under the LTIP*.

(4) Amounts represent the STIP bonus earned for the respective year. STIP payments are made in the first quarter of the year following the year in which they are earned. Other than this bonus, there were no other applicable bonuses earned or deferred associated with year 2013. Please see Item 11. Compensation Discussion and Analysis Compensation Program Components *Annual Cash Incentive Bonus Awards*.

(5) For all Named Executive Officers, the amounts represent the sum of the (a) SERP phantom unit contributions valued at the market closing price of our common units on the date the phantom unit was granted, (b) profit sharing savings plan employer contribution and (c) perquisites in excess of $10,000. A reconciliation of the amounts shown is as follows:

	Year	SERP	Profit Sharing Plan Employer Contribution	Perquisites (a)	Total
Joseph W. Craft III	2014	$ 389,028	$ 20,800	$ -	$ 409,828

	2013	341,873	20,400	10,053	372,326
	2012	282,867	20,000	-	302,867
Brian L. Cantrell	2014	56,307	20,800	10,485	87,592
	2013	45,501	20,400	-	65,901
	2012	44,426	20,000	-	64,426
R. Eberley Davis	2014	81,504	20,800	-	102,304
	2013	64,032	20,400	-	84,432
	2012	61,901	20,000	-	81,901
Robert G. Sachse	2014	103,941	20,800	11,886	136,627
	2013	78,228	20,400	25,500	124,128
	2012	76,617	20,000	11,462	108,079
Thomas M. Wynne	2014	66,581	20,800	18,845	106,226
	2013	54,027	20,400	-	74,427
	2012	50,390	20,000	-	70,390

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a) For Mr. Craft, the 2013 amount includes perquisites and other personal benefits comprised of club dues of $10,053. For Mr. Cantrell, the 2014 amount includes perquisites and other personal benefits totaling $10,485 comprised of club dues of $9,415 and tax preparation fees of $1,070. For Mr. Sachse, the 2014 amount includes perquisites and other personal benefits comprised of club dues of $11,886, the 2013 amount includes perquisites and other personal benefits totaling $25,500 comprised of club dues of $14,330 and tax preparation fees of $11,170 and the 2012 amount includes perquisites and other personal benefits totaling $11,462 comprised of club dues. For Mr. Wynne, the 2014 amount includes perquisites and other personal benefits totaling $18,845 comprised of tax preparation fees of $14,145 and club dues of $4,700.

Grants of Plan-Based Awards Table

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Unit Awards: Number of Units (3)	All Other Option Awards: Number of Securities Underlying Options (1)	Exercise or Base Price of Options Awards (1)	Grant Date Fair Value of Unit Awards (5)
Name	**Grant Date**	**Approved Date**	**Threshold (8)**	**Target (7)**	**Maximum (8)**	**Threshold (4)**	**Target (2)**	**Maximum (4)**				
Joseph W. Craft III	February 14, 2014	(6)					-		2,140			$ 86,959
	May 15, 2014	(6)					-		1,952			89,909
	August 14, 2014	(6)					-		1,946			93,194
	November 14, 2014	(6)					-		2,028			97,527
	December 31, 2014	January 26, 2015		$ -			-		498			21,439
				-			-		8,564			389,028
Brian L. Cantrell	February 6, 2014	February 6, 2014					14,968		-			607,401
	February 14, 2014	(6)					-		140			5,689
	May 15, 2014	(6)					-		128			5,896
	August 14, 2014	(6)					-		127			6,082
	November 14, 2014	(6)					-		133			6,396
	December 31, 2014	January 26, 2015					-		749			32,244
		February 11, 2015		412,500			-		-			-
				412,500			14,968		1,277			663,708
R. Eberley Davis	February 6, 2014	February 6, 2014					19,118		-			775,808
	February 14, 2014	(6)					-		156			6,339
	May 15, 2014	(6)					-		142			6,541
	August 14, 2014	(6)					-		141			6,752
	November 14, 2014	(6)					-		147			7,069
	December 31, 2014	January 26, 2015					-		1,273			54,803

		February 11, 2015	465,000	-	-	-
			465,000	19,118	1,859	857,312
Robert G. Sachse	February 6, 2014	February 6, 2014		21,710	-	880,992
	February 14, 2014	(6)		-	210	8,533
	May 15, 2014	(6)		-	192	8,844
	August 14, 2014	(6)		-	191	9,147
	November 14, 2014	(6)		-	199	9,570
	December 31, 2014	January 26, 2015		-	1,576	67,847
		February 11, 2015	511,500	-	-	-
			511,500	21,710	2,368	984,933
Thomas M. Wynne	February 6, 2014	February 6, 2014		21,118	-	856,968
	February 14, 2014	(6)		-	184	7,477
	May 15, 2014	(6)		-	168	7,738
	August 14, 2014	(6)		-	167	7,998
	November 14, 2014	(6)		-	174	8,368
	December 31, 2014	January 26, 2015		-	813	35,000
		February 11, 2015	538,500	-	-	-
			$538,500	21,118	1,506	$ 923,549

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(1) Column not applicable.

(2) These awards are grants of restricted units pursuant to our LTIP. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

(3) These awards are phantom units added to each Named Executive Officer s SERP notional account balance. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

(4) Grants of restricted units under our LTIP are not subject to minimum thresholds, targets or maximum payout conditions. However, the vesting of these grants is subject to the satisfaction of certain performance criteria. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

(5) We calculated the fair value of LTIP awards using a value of $40.58 per unit, the unit price applicable for 2014 grants. We calculated the fair value of SERP phantom unit awards using the market closing price on the date the phantom unit award was granted. Phantom units granted under the SERP vest on the date granted.

(6) In accordance with the provisions of the SERP, a participant s cumulative notional phantom unit account balance earns the equivalent of common unit distributions when we pay a distribution to our common unitholders, which is added to the account balance in the form of phantom units. These contributions are made in accordance with the SERP plan document that has been approved by the Compensation Committee. Therefore, these contributions are not separately approved by the Compensation Committee.

(7) These amounts represent awards pursuant to our STIP. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Annual Cash Incentive Bonus Awards* for additional information regarding the STIP awards.

(8) Awards under our STIP are subject to a minimum financial performance target each year. However, determination of individual awards under the STIP is based upon an assessment of the Named Executive Officer s performance, comparative compensation data of companies in our peer group and recommendation of the President and Chief Executive Officer. The STIP does not specify any threshold or maximum payout amounts. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Annual Cash Incentive Bonus Awards* for additional information regarding the STIP awards.

Narrative Disclosure Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Cash Incentive Bonus Awards

Under the STIP, our Named Executive Officers are eligible for cash awards for our achieving an annual financial performance target. The annual performance target is recommended by the President and Chief Executive Officer of our managing general partner and approved by the Compensation Committee, typically in January of each year. The performance target historically has been EBITDA-based, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the pure operating results of the core mining business. (EBITDA is calculated as net income before net interest expense, income taxes, depreciation, depletion and amortization and net income attributable to noncontrolling interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target. The cash available generally increases in relationship to our EBITDA, as adjusted, exceeding the minimum financial performance target and is subject to adjustment by the Compensation Committee in its discretion. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Annual Cash Incentive Bonus Awards*.

Long-Term Incentive Plan

Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our managing general partner s President and Chief Executive Officer, subject to the review and approval of the Compensation Committee. Restricted units granted under the LTIP are phantom or notional units that upon vesting entitle the participant to receive an ARLP unit. Restricted units granted under the LTIP vest at the end of a

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stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. The performance target is based on a normalized EBITDA measure, with that measure typically being the same as the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant s cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant s termination or death in ARLP common units equal to the number of phantom units then credited to the participant s account, subject to reduction of the number of units distributed to cover withholding obligations. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

Salary and Bonus in Proportion to Total Compensation

The following table shows the total of salary and bonus in proportion to total compensation from the Summary Compensation Table:

Name	**Year**	**Salary and Bonus ($)**	**Total Compensation ($)**	**Salary and Bonus as a % of Total Compensation**
Joseph W. Craft III	2014	$ 334,828	$ 744,656	45.0%
	2013	334,828	707,154	47.3%
	2012	334,828	637,695	52.5%
Brian L. Cantrell	2014	282,096	1,389,589	20.3%
	2013	275,000	1,162,565	23.7%
	2012	259,773	981,587	26.5%
R. Eberley Davis	2014	321,827	1,664,939	19.3%
	2013	310,000	1,304,139	23.8%
	2012	291,002	1,173,806	24.8%
Robert G. Sachse	2014	320,250	1,849,369	17.3%
	2013	310,000	1,471,539	21.1%
	2012	299,398	1,169,024	25.6%
Thomas M. Wynne	2014	370,827	1,872,521	19.8%
	2013	359,000	1,484,613	24.2%
	2012	335,164	1,216,491	27.6%

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Outstanding Equity Awards at Fiscal Year-End Table

Name	Number of Securities Underlying Unexercised Options Exercisable (1)	Number of Securities Underlying Unexercised Options Unexerciseable (1)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (1)	Option Exercise Price (1)	Option Expiration Date (1)	Market Value of Units That Have Not Vested (1)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (2)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested (3)
Joseph W. Craft III							-	$ -
Brian L. Cantrell							38,826	1,671,459
R. Eberley Davis							47,698	2,053,399
Robert G. Sachse							51,744	2,227,579
Thomas M. Wynne							54,922	2,364,392

(1) Column is not applicable.

(2) Amounts represent restricted units awarded under the LTIP that were not vested as of December 31, 2014. Subject to our achieving financial performance targets, the units vested, or will vest, as follows: For Mr. Cantrell, 9,524 on January 1, 2015, 14,334 on January 1, 2016 and 14,968 units on January 1, 2017; Mr. Davis, 12,880 on January 1, 2015, 15,700 on January 1, 2016 and 19,118 units on January 1, 2017; for Mr. Sachse, 11,868 on January 1, 2015, 18,166 on January 1, 2016 and 21,710 units on January 1, 2017; and for Mr. Wynne, 13,138 on January 1, 2015, 20,666 on January 1, 2016 and 21,118 units on January 1, 2017. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*. All grants of restricted units under the LTIP include the contingent right to receive quarterly cash distributions in an amount equal to the cash distributions we make to unitholders during the vesting period.

(3) Stated values are based on $43.05 per unit, the closing price of our common units on December 31, 2014, the final market trading day of 2014.

Option Exercises and Units Vested Table

	Option Awards		Unit Awards	
Name	Number of Units Acquired on Exercise (1)	Value Realized on Exercise (1)	Number of Units Acquired on Vesting (2)	Value Realized on Vesting (2)
Joseph W. Craft III			-	$ -

Brian L. Cantrell	10,000	384,000
R. Eberley Davis	10,000	384,000
Robert G. Sachse	13,900	533,760
Thomas M. Wynne	14,000	537,600

(1) Column is not applicable.

(2) Amounts represent the number and value of restricted units granted under the LTIP that vested in 2014. All of these units vested on January 1, 2014 and are valued at $38.40 per unit, the closing price on January 2, 2014, the first market trading date of 2014. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

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Pension Benefits Table

Name	Plan Name	Year	Number of Years Credited Service (1)	Present Value of Accumulated Benefit (2)	Payments During Last Fiscal Year
Joseph W. Craft III	SERP	2014		$ 6,653,205	$ -
Brian L. Cantrell	SERP	2014		464,122	-
R. Eberley Davis	SERP	2014		535,241	-
Robert G. Sachse	SERP	2014		717,902	-
Thomas M. Wynne	SERP	2014		601,409	-

(1) Column not applicable because no provision of the SERP is affected by years of service.

(2) Amounts represent the Named Executive Officer s cumulative notional account balance of phantom units valued at $43.05, the closing price of our common units on December 31, 2014, the final market trading day of 2014. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

Narrative Discussion Relating to the Pension Benefits Table for 2014

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to their percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant s cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant s termination or death in ARLP common units equal to the number of phantom units then credited to the participant s account, subject to reduction of the number of units distributed to cover withholding obligations. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

Potential Payments Upon a Termination or Change of Control

Each of our Named Executive Officers is eligible to receive accelerated vesting and payment under the LTIP and the SERP upon certain terminations of employment or upon our change in control. Upon a change of control, as defined in the LTIP, all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. In this regard, all restricted periods shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level. The LTIP defines a change in control as one of the following events: (1) any sale, lease, exchange or other transfer of all or substantially all of our assets or our managing general partner s assets to any person other than a person who is our affiliate; (2) the consolidation or merger of our managing general partner with or into another person pursuant to a transaction in which the outstanding voting interests of our managing general partner is changed into or exchanged for cash, securities or other property, other than any such transaction where (a) the outstanding voting interests of our managing general partner are changed into or exchanged for voting stock or interests of the surviving corporation or its parent and (b) the holders of the voting interests of our managing general partner immediately prior to such transaction own, directly or indirectly, not less than a majority of the voting stock or interests of the surviving corporation or its parent immediately after such transaction; or (3) a person or group being or becoming the beneficial owner of more than 50% of all voting interests of our managing general partner then outstanding.

The amounts each of our Named Executive Officers could receive under the SERP have been previously disclosed in Item 11. Pension Benefits Table for 2014 and the amounts each of the Named Executive Officers could receive under the LTIP have been previously disclosed in Item 11. Outstanding Equity Awards at Fiscal Year-End 2014 Table , in each case assuming the triggering event occurred on December 31, 2014. In addition, if a Named Executive Officer s

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employment were terminated as a result of one of certain enumerated events, the Named Executive Officer would receive an amount based on an allocation for the year of termination. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan* for additional information regarding the enumerated events and allocation determination. The exact amount that any Named Executive Officer would receive could only be determined with certainty upon an actual termination or change in control.

Director Compensation

The compensation of the directors of our managing general partner, MGP, is set by the Board of Directors upon recommendation of the Compensation Committee. Mr. Craft and Mr. Wesley, our only employee directors, receive no director compensation. The directors of MGP devote 100% of their time as directors of MGP to the business of the ARLP Partnership.

Director Compensation Table for 2014

Name	Fees earned or Paid in Cash ($)	Unit Awards ($) (2)(4)	Option Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)(1)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(1)	All Other Compensation ($)(3)	Total ($)
Michael J. Hall	$ -	$ 105,941	$ -	$ -	$ -	$ 5,000	$ 110,941
John P. Neafsey	193,750	116,127	-	-	-	5,000	314,877
John H. Robinson	165,000	-	-	-	-	5,000	170,000
Wilson M. Torrence	155,000	16,141	-	-	-	-	171,141

(1) Column is not applicable.

(2) Amounts represent the grant date fair value of equity awards in 2014 related to deferrals of annual retainer and distributions earned on deferred units (computed in accordance with FASB ASC 718, using the same assumptions as used for financial reporting purposes). Please see *Narrative to Director Compensation Table*, below.

(3) All Other Compensation for Messrs. Hall, Neafsey and Robinson includes matching charitable contributions made by us. We match individual contributions of $25 or more to educational institutions and not-for-profit organizations on a one-to-one basis up to $5,000 per individual, per calendar year.

(4) At December 31, 2014, each director had the following number of phantom ARLP common units credited to his notional account under the MGP s Amended and Restated Deferred Compensation Plan for Directors (Deferred Compensation Plan):

Name	Directors Deferred Compensation Plan (in Units)
Michael J. Hall	8,531
John P. Neafsey	48,916

John H. Robinson	-
Wilson M. Torrence	5,175

Please see Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters for information regarding our Directors beneficial ownership of ARLP common units.

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Narrative to Directors Compensation Table

Compensation for our non-employee directors includes an annual cash retainer paid quarterly in advance on a pro rata basis. The annual retainer for calendar year 2014 was $155,000 for each director other than Mr. Hall, and $77,500 for Mr. Hall. In addition, Mr. Neafsey was entitled to cash compensation of $38,750 for service as Chairman of the Board of Directors and Mr. Robinson and Mr. Hall each was entitled to cash compensation $10,000 for service as Chairman of the Compensation Committee and Audit Committee, respectively. Mr. Hall is also a director and chairman of the audit committee of AGP, the general partner of AHGP, and received like compensation for his service in those roles. Directors have the option to defer all or part of their cash compensation pursuant to the Deferred Compensation Plan by completing an election form prior to the beginning of each calendar year. Only Mr. Hall elected to defer cash compensation in 2014 pursuant to the Deferred Compensation Plan, deferring all of his cash compensation for 2014.

Pursuant to the Deferred Compensation Plan, a notional account is established for deferred amounts of cash compensation and credited with notional common units of ARLP, described in the plan as phantom units. The number of phantom units credited is determined by dividing the amount deferred by the average closing unit price for the ten trading days immediately preceding the deferral date. When quarterly cash distributions are made with respect to ARLP common units, an amount equal to such quarterly distribution is credited to the notional account as additional phantom units. Payment of accounts under the Deferred Compensation Plan will be made in ARLP common units equal to the number of phantom units then credited to the director s account.

Directors may elect to receive payment of the account resulting from deferrals during a plan year either (a) on the January 1 on or next following their separation from service as a director or (b) on the earlier of a specified January 1 or the January 1 on or next following their separation from service. The payment election must be made prior to each plan year; if no election is made, the account will be paid on the January 1 on or next following the director s separation from service. The Deferred Compensation Plan is administered by the Compensation Committee, and the Board of Directors may change or terminate the plan at any time; provided, however, that accrued benefits under the plan cannot be impaired.

Upon any recapitalization, reorganization, reclassification, split of common units, distribution or dividend of securities on ARLP common units, our consolidation or merger, or sale of all or substantially all of our assets or other similar transaction that is effected in such a way that holders of common units are entitled to receive (either directly or upon subsequent liquidation) cash, securities or assets with respect to or in exchange for ARLP common units, the Compensation Committee shall, in its sole discretion (and upon the advice of financial advisors as may be retained by the Compensation Committee), immediately adjust the notional balance of phantom units in each director s account under the Deferred Compensation Plan to equitably credit the fair value of the change in the ARLP common units and/or the distributions (of cash, securities or other assets) received or economic enhancement realized by the holders of the ARLP common units.

Our Board of Directors has established a recommendation that each non-employee director should attain within five years following such person s election to the Board of Directors, and thereafter maintain during service on the Board of Directors, ownership of equity of ARLP (including phantom equity ownership under the Deferred Compensation Plan) with an aggregate value of $220,000.

Compensation Committee Interlocks and Insider Participation

Mr. Craft is a director and the President and Chief Executive Officer of our managing general partner and is Chairman of the Board of Directors, President and Chief Executive Officer of AGP, the general partner of AHGP. Otherwise, none of our executive officers serves as a member of the Board of Directors or Compensation Committee of any entity that has one or more of its executive officers serving as a member of the Board of Directors or Compensation Committee of our managing general partner.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The following table sets forth certain information as of February 13, 2015, regarding the beneficial ownership of common units held by (a) each director of our managing general partner, (b) each executive officer of our managing general partner identified in the Summary Compensation Table included in Item 11. Executive Compensation above, (c) all such directors and executive officers as a group, and (d) each person known by our managing general partner to be the beneficial owner of 5% or more of our common units. Our managing general partner is owned by AHGP, which is reflected as a 5% common unitholder in the table below. Approximately 70% of the equity of AHGP is owned by certain parties (some of whom are current or former members of management) who may comprise a group under Rule 13d-5(b) of the Exchange Act as a result of being subject to a transfer restrictions agreement entered into in connection with the AHGP IPO. Our special general partner is a wholly owned subsidiary of ARH, which is indirectly owned by Mr. Craft and Kathleen S. Craft. The address of each of AHGP, ARH, our managing general partner, our special general partner, and unless otherwise indicated in the footnotes to the table below, each of the directors and executive officers reflected in the table below is 1717 South Boulder Avenue, Suite 400, Tulsa, Oklahoma 74119. Unless otherwise indicated in the footnotes to the table below, the common units reflected as being beneficially owned by our managing general partner s directors and Named Executive Officers are held directly by such directors and officers. The percentage of common units beneficially owned is based on 74,188,784 common units outstanding as of February 13, 2015.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Directors and Executive Officers		
Joseph W. Craft III (1)	31,805,240	42.9%
Michael J. Hall	-	*
John P. Neafsey	31,604	*
John H. Robinson	18,462	*
Wilson M. Torrence	34,796	*
Charles R. Wesley III	-	*
Brian L. Cantrell (2)	79,766	*
R. Eberley Davis	46,485	*
Robert G. Sachse (3)	80,723	*
Thomas M. Wynne	35,562	*
All directors and executive officers as a group (10 persons)	32,132,638	43.3%
5% Common Unit Holders		
Alliance Holdings GP, L.P. (4)	31,088,338	41.9%

* Less than one percent.

(1) The common units attributable to Mr. Craft consist of (i) 714,902 common units held directly by him, (ii) 2,000 common units held by his son, and (iii) 31,088,338 common units held by AHGP. Mr. Craft is Chairman of the Board of Directors, and through his ownership of C-Holdings, LLC, the sole owner of AGP, the general partner of AHGP, and he holds, directly or indirectly, or may be deemed to be the beneficial owner of, a majority of the outstanding common units of AHGP. AHGP owned approximately 41.9% of our common units as of February 13, 2015. Mr. Craft disclaims beneficial ownership of the common units held by AHGP except to the extent of his pecuniary interest therein.

(2) Of the common units held by Mr. Cantrell, 49,516 ARLP common units are subject to a pledge agreement in favor of MidFirst Bank.

(3) Of the common units held by Mr. Sachse, 39,992 ARLP common units are subject to a pledge agreement in favor of JPMorgan Chase Bank, N.A.

(4) See footnote (1) above and the paragraph preceding the above table for explanation of the relationship between AHGP, Mr. Craft and us.

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Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of December 31, 2014	Weighted-average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans as of December 31, 2014
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	843,340	N/A	3,908,230
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	306,359	N/A	N/A
Deferred Compensation Plan for Directors	62,622	N/A	N/A

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

Certain Relationships and Related Transactions

As of December 31, 2014, AHGP owned 31,088,338 common units representing 42.0% of our common units and our IDR. In addition, our general partners own, on a combined basis, an aggregate 2% general partner interest in us, the Intermediate Partnership and the subsidiaries. Our managing general partner s ability, as managing general partner, to control us together with AHGP s ownership of 42.0% of our common units, effectively gives our managing general partner the ability to veto our actions and to control our management.

Certain of our officers and directors are also officers and/or directors of AHGP, including Mr. Craft, the President and Chief Executive Officer of our managing general partner, Mr. Hall, a Director, member of the Compensation Committee and Chairman of the Audit Committee of the MGP Board of Directors, Mr. Cantrell, the Senior Vice President and Chief Financial Officer of our managing general partner, and Mr. Davis, the Senior Vice President, General Counsel and Secretary of our managing general partner.

Transactions Between Us, SGP, SGP Land, ARH, ARH II and AHGP

The Board of Directors and its Conflicts Committee review our related-party transactions that involve a potential conflict of interest between a general partner and ARLP or its subsidiaries or another partner to determine that such transactions reflect market-clearing terms and conditions customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to us and our limited partners.

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into an Administrative Services Agreement with our managing general partner, our Intermediate Partnership, AHGP and its general partner AGP, and ARH II. The Administrative Services Agreement superseded a similar 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, 2014 of $0.4 million from AHGP and $0.1 million from ARH II.

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, director fees and expenses, management s salaries and related benefits (including incentive compensation), and accounting, budgeting, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed to us by our managing general partner and its affiliates were approximately $0.8 million for the year ended December 31, 2014. The executive officers of our managing general partner are employees of and paid by Alliance Coal, and the reimbursement we pay to our managing general partner pursuant to the partnership agreement does not include any compensation expenses associated with them.

Managing General Partner Contribution

During December 2014, an affiliated entity controlled by Mr. Craft contributed $1.5 million to AHGP for the purpose of funding certain of our general and administrative expenses. Upon AHGP s receipt of this contribution, it contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made a special allocation to our managing general partner of certain general and administrative expenses equal to the amount of its contribution.

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White Oak Transactions

On September 22, 2011, we entered into a series of transactions with White Oak and related entities to support development of a longwall mining operation. The initial longwall system commenced operation in late October 2014. The transactions feature several components, including an equity investment containing certain distribution and liquidation preferences, the acquisition and lease-back of certain reserves and surface rights, a coal handling and services agreement and a loan for surface facilities. The transactions are expected to generate equity distributions and have begun generating royalties and throughput revenues. For more information on White Oak, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments.

In addition to the agreements discussed above, White Oak also has agreements with our subsidiaries for the purchase of various services and products, including for coal handling services provided by our Mt. Vernon transloading facility. For the year ended December 31, 2014, we recorded revenues of $3.9 million for services and products provided by Mt. Vernon and Matrix Design to White Oak, which are included in Other sales and operating revenues on our consolidated statements of income. For information on royalties and throughput revenues, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments.

SGP Land, LLC

SGP Land is owned by our special general partner, SGP, which is owned indirectly by Mr. Craft and Kathleen S. Craft.

In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty of $0.3 million until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $0.9 million during the year ended December 31, 2014. As of December 31, 2014, all advanced minimum royalties paid under the lease have been recouped.

SGP

In 2005, Tunnel Ridge entered into a coal lease agreement with SGP, our special general partner, requiring advance minimum royalty payments of $3.0 million per year. As of December 31, 2014, Tunnel Ridge had paid $10.7 million of advance minimum royalty payments pursuant to the lease which are available for recoupment. The advance royalty payments are fully recoupable against earned royalties. Tunnel Ridge also controls surface land and other tangible assets under a separate lease agreement with SGP. Under the terms of the lease agreement, Tunnel Ridge has paid and will continue to pay SGP an annual lease payment of $0.2 million. Lease expense was $0.2 million for the year ended December 31, 2014.

We have a noncancelable lease arrangement for the Gibson North coal preparation plant and ancillary facilities with SGP. The lease arrangement is considered a capital lease based on the terms of the arrangement. Lease payments for the year ended December 31, 2014 were $0.6 million.

Joseph W. Craft III

Our subsidiary, ASI, has a time-sharing agreement with Mr. Craft and Mr. Craft s affiliate, JC Land, concerning their use of aircraft owned by ASI for purposes other than our business. In accordance with the provisions of that agreement, Mr. Craft and JC Land paid ASI $0.1 million for the year ended December 31, 2014 for use of the aircraft. In addition, Alliance Coal has a time-sharing agreement with JC Land concerning Alliance Coal s use of an airplane owned by JC Land. In accordance with the provisions of that agreement, Alliance Coal paid JC Land $0.2 million for the year ended December 31, 2014 for use of the aircraft.

Effective August 1, 2013, Alliance Coal entered into an expense reimbursement agreement with JC Land regarding pilots hired by Alliance Coal to operate aircraft owned by ASI and JC Land. In accordance with the expense reimbursement agreement, JC Land reimburses Alliance Coal for a portion of the compensation expense for its pilots. JC Land paid us $0.2 million in 2014 pursuant to this agreement.

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WKY CoalPlay

On November 17, 2014, SGP Land and the Craft Companies entered into a limited liability company agreement to form WKY CoalPlay. WKY CoalPlay was formed, in part, to purchase and lease coal reserves. WKY CoalPlay is managed by an entity controlled by an officer of ARH who is also a director of ARH II, the indirect parent of SGP, an employee of SGP Land and a trustee of the irrevocable trusts owning the Craft Companies.

In December 2014, WKY CoalPlay acquired approximately 86.6 million tons of proven and probable high-sulfur coal reserves in western Kentucky and southern Indiana through its purchase of two indirect subsidiaries of CONSOL Energy Inc. for $57.2 million. WKY CoalPlay s acquired subsidiaries subsequently leased 72.3 million tons of the acquired reserves to us and, as partial consideration for entering the leases, conveyed the remaining 14.3 million tons of its acquired reserves to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a mine plan. The leases have initial terms ranging from 7 to 20 years and provide for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $6.2 million. All annual minimum royalty payments are recoupable against earned royalty payments. WKY CoalPlay also granted to us an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the leases. We paid WKY CoalPlay $6.2 million in January 2015 for the initial annual minimum royalty payment.

In December 2014, WKY CoalPlay acquired approximately 54.1 million tons of proven and probable high-sulfur coal reserves in western Kentucky through its purchase of a subsidiary of Midwest for $29.6 million. In conjunction with this acquisition, WKY CoalPlay s acquired subsidiary leased 22.6 million tons of the acquired reserves to us and, as partial consideration for entering the leases, conveyed the remaining 31.5 million tons of its acquired reserves to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a mine plan. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $2.5 million. All annual minimum royalty payments are recoupable against earned royalty payments. WKY CoalPlay also granted to us an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the lease. We paid WKY CoalPlay $2.5 million in January 2015 for the initial annual minimum royalty payment.

In February 2015, WKY CoalPlay acquired approximately 39.1 million tons of proven and probable high-sulfur owned coal reserves located in Henderson and Union Counties, Kentucky from Central States, a subsidiary of Patriot, for $25.0 million and in turn leased those reserves to us. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $2.1 million. All annual minimum royalty payments are recoupable against earned royalty payments. An option was also granted to us to acquire the leased reserves at any time during a three-year period beginning in February 2018 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments under the lease. We paid WKY CoalPlay $2.1 million in February 2015 for the initial annual minimum royalty payment.

Cavalier Minerals

On November 10, 2014, Cavalier Minerals contributed $7.4 million in return for a limited partner interest in AllDale Minerals, an entity created to purchase oil and gas mineral interests in various geographical locations within producing basins in the continental United States. Additional contributions totaling $4.2 million were made to AllDale Minerals prior to December 31, 2014 with the remaining commitment of $37.4 million expected to be paid over the next two to four years. AllDale Minerals is managed and controlled by its general partner, AllDale Minerals Management. AllDale Minerals Management is owned by four members, consisting of three parties unrelated to us or our affiliates and Bluegrass Minerals, which is owned by an officer of ARH. See Item 8. Financial Statements and Supplementary Data Note 11. Noncontrolling Interest and Note 12. Equity Investments.

Omnibus Agreement

Concurrent with the closing of our initial public offering, we entered into an omnibus agreement with ARH and our general partners, which govern potential competition among us and the other parties to this agreement. The omnibus agreement was amended in May 2002. Pursuant to the terms of the amended omnibus agreement, ARH agreed, and

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caused its controlled affiliates to agree, for so long as management controls our managing general partner, not to engage in the business of mining, marketing or transporting coal in the U.S., unless it first offers us the opportunity to engage in a potential activity or acquire a potential business, and the Board of Directors, with the concurrence of its Conflicts Committee, elects to cause us not to pursue such opportunity or acquisition. In addition, ARH has the ability to purchase businesses, the majority value of which is not mining, marketing or transporting coal, provided ARH offers us the opportunity to purchase the coal assets following their acquisition. The restriction does not apply to the assets retained and business conducted by ARH at the closing of our initial public offering. Except as provided above, ARH and its controlled affiliates are prohibited from engaging in activities wherein they compete directly with us. In addition to its non-competition provisions, the agreement also provides for indemnification of us against liabilities associated with certain assets and businesses of ARH that were disposed of or liquidated prior to consummating our initial public offering. In May 2006, in connection with the closing of the AHGP IPO, the omnibus agreement was amended to include AHGP and AGP as parties to the agreement.

Director Independence

As a publicly traded limited partnership listed on the NASDAQ Global Select Market, we are required to maintain a sufficient number of independent directors on the board of our managing general partner to satisfy the audit committee requirement set forth in NASDAQ Rule 4350(d)(2). Rule 4350(d)(2) requires us to maintain an audit committee of at least three members, each of whom must, among other requirements, be independent as defined under NASDAQ Rule 4200(a)(15) and meet the criteria for independence set forth in Rule 10A-3(b)(1) under the Exchange Act (subject to the exemptions provided in Rule 10A-3(c)).

All members of the Audit Committee Messrs. Hall, Robinson and Torrence and all members of the Compensation Committee Messrs. Robinson, Neafsey, Hall and Torrence are independent directors as defined under applicable NASDAQ and Exchange Act rules. Please see Item 10. Directors, Executive Officers and Corporate Governance of the Managing General Partner Audit Committee and Item 11. Executive Compensation Compensation Discussion and Analysis.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The firm of Ernst & Young LLP is our independent registered public accounting firm. Fees paid to Ernst & Young LLP during the last two fiscal years were as follows:

Audit Fees. Fees for audit services provided for the years ended December 31, 2014 and 2013 were $0.9 million. Audit services consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with GAAP.

Audit-Related Fees. There were no audit-related fees for the years ended December 31, 2014 and 2013.

Tax Fees. Fees for tax services provided for the years ended December 31, 2014 and 2013 were $0.3 million and $0.4 million, respectively. Tax services consist primarily of services rendered for tax compliance, tax advice, and tax planning.

All Other Fees. There were no other fees for the years ended December 31, 2014 and 2013.

The charter of the Audit Committee provides that the committee is responsible for the pre-approval of all auditing services and permitted non-audit services to be performed for us by our independent registered public accounting firm, subject to the requirements of applicable law. In accordance with such charter, the Audit Committee may delegate the authority to grant such pre-approvals to the Audit Committee chairman or a sub-committee of the Audit Committee, which pre-approvals are then reviewed by the full Audit Committee at its next regular meeting. Typically, however, the Audit Committee itself reviews the matters to be approved. The Audit Committee periodically monitors the services

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rendered by and actual fees paid to the independent registered public accounting firm to ensure that such services are within the parameters approved by the Audit Committee.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements.

The response to this portion of Item 15 is submitted as a separate section herein under Part II, Item 8. Financial Statements and Supplementary Data.

(a)(2) Financial Statement Schedule.

Schedule II Valuation and Qualifying Accounts Years ended December 31, 2014, 2013 and 2012, is set forth under Part II, Item 8. Financial Statements and Supplementary Data. All other schedules are omitted because they are not applicable or the information is shown in the financial statements or notes thereto.

(a)(3) and (c) The exhibits listed below are filed as part of this annual report.

		Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File No. and Film No.**	**Exhibit**	**Filing Date**	**Filed Herewith***
3.1	Third Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 14922391	3.1	06/16/2014	
3.2	Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 051159681	3.1	10/27/2005	
3.3	Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P.	10-K	000-26823 583595	3.2	03/29/2000	
3.4	Certificate of Limited Partnership of Alliance Resource Partners, L.P	S-1	333-78845 99630855	3.6	05/20/1999	

3.5	Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P.	S-1/A	333-78845 99669102	3.8	07/23/1999
3.6	Certificate of Formation of Alliance Resource Management GP, LLC	S-1/A	333-78845 99669102	3.7	07/23/1999
3.7	Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC	S-3	333-85282 02596627	3.4	04/01/2002
3.8	Amendment No. 1 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC	S-3	333-85282 02596627	3.5	04/01/2002
3.9	Amendment No. 2 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC	S-3	333-85282 02596627	3.6	04/01/2002
3.10	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 06993800	3.1	08/01/2006
3.11	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L. P. dated October 25, 2007	10-K	000-26823 08654096	3.10	02/29/2008

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			Incorporated by Reference			
Exhibit Number	Exhibit Description	Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
3.12	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., dated April 14, 2008	8-K	000-26823 08763867	3.1	04/18/2008	
4.1	Form of Common Unit Certificate (Included as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., included in this Exhibit Index as Exhibit 3.1).	8-K	000-26823 08763867	3.1	04/18/2008	
10.1	Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein.	10-K	000-26823 583595	10.2	03/29/2000	
10.2	Amendment and Restatement of Letter of Credit Facility Agreement dated October 2, 2010.	10-Q	000-26823 11823116	10.1	05/09/2011	
10.3	Letter of Credit Facility Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association.	10-Q	000-26823 1782487	10.25	11/13/2001	
10.4	First Amendment to the Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association.	10-Q	000-26823 02827517	10.32	11/14/2002	
10.5	Promissory Note Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, N.A.	10-Q	000-26823 1782487	10.26	11/13/2001	
10.6	Guarantee Agreement, dated as of October 2, 2001, between Alliance Resource GP, LLC and Bank of the Lakes, N.A.	10-Q	000-26823 1782487	10.27	11/13/2001	
10.7	Contribution and Assumption Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. and the other parties named therein	10-K	000-26823 583595	10.3	03/29/2000	
10.8	Omnibus Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC and Alliance Resource Partners, L.P.	10-K	000-26823 583595	10.4	03/29/2000	

10.9(1)	Amended and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.17	03/15/2004
10.10(1)	First Amendment to the Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.18	03/15/2004
10.11(1)	Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 583595	10.12	03/29/2000
10.12(1)	Alliance Coal, LLC Supplemental Executive Retirement Plan	S-8	333-85258 02595143	99.2	04/01/2002

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Exhibit Number	Exhibit Description	Incorporated by Reference: Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.13(1)	Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	S-8	333-85258 02595143	99.3	04/01/2002	
10.14	Guaranty by Alliance Resource Partners, L.P. dated March 16, 2012	10-Q	000-26823 12825281	10.3	05/09/2012	
10.15(2)	Base Contract for Purchase and Sale of Coal, dated March 16, 2012, between Seminole Electric Cooperative, Inc. and Alliance Coal, LLC	10-Q	000-26823 12825281	10.1	05/09/2012	
10.16(2)	Contract of Confirmation, effective March 16, 2012, between Seminole Electric Cooperative, Inc., Alliance Coal, LLC and Alliance Resource Partners, L.P.	10-Q/A	000-26823 12947715	10.2	07/05/2012	
10.17	Amended and Restated Charter for the Audit Committee of the Board of Directors dated February 23, 2009	10-K	000-26823 09647063	10.35	03/02/2009	
10.18	Second Amendment to the Omnibus Agreement dated May 15, 2006 by and among Alliance Resource Partners, L.P., Alliance Resource GP, LLC, Alliance Resource Management GP, LLC, Alliance Resource Holdings, Inc., Alliance Resource Holdings II, Inc., AMH-II, LLC, Alliance Holdings GP, L.P., Alliance GP, LLC and Alliance Management Holdings, LLC	10-Q	000-26823 061017824	10.1	08/09/2006	
10.19	Administrative Services Agreement dated May 15, 2006 among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Holdings GP, L.P. and Alliance GP, LLC	10-Q	000-26823 061017824	10.2	08/09/2006	
10.20(1)	First Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 07660999	10.50	03/01/2007	
10.21(1)	Second Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 08654096	10.50	02/29/2008	
10.22(1)	Second Amendment to the Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan	10-K	000-26823 07660999	10.51	03/01/2007	

10.23(1)	Third Amendment to the Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan	8-K	000-26823 091143421	10.1	10/29/2009
10.24(1)	First Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 07660999	10.52	03/01/2007
10.25(1)	Second Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 08654096	10.53	02/29/2008
10.26	First Amendment to the Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	10-K	000-26823 07660999	10.53	03/01/2007
10.27	Second Amendment to the Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	10-K	000-26823 08654096	10.55	02/29/2008

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.28	Third Amended and Restated Credit Agreement, dated as of May 23, 2012, by and among Alliance Resource Operating Partners, L.P., as borrower, the initial lenders, initial issuing banks and swingline bank named therein, JPMorgan Chase Bank, N.A., as administrative agent, J.P. Morgan Securities, LLC, Wells Fargo Securities, LLC and Citigroup Global Markets Inc. as joint lead arrangers and joint bookrunners, Wells Fargo Bank, National Association and Citibank, N.A., as syndication agents, and the other institutions named therein as documentation agents.	8-K	000-26823 12865660	99.1	05/24/2012	
10.29	Note Purchase Agreement, 6.28% Senior Notes Due June 26, 2015, and 6.72% Senior Notes due June 26, 2018, dated as of June 26, 2008, by and among Alliance Resource Operating Partners, L.P. and various investors	8-K	000-26823 08928968	10.1	07/01/2008	
10.30	First Amendment, dated as of June 26, 2008, to the Note Purchase Agreement, dated August 16, 1999, 8.31% Senior Notes due August 20, 2014, by and among Alliance Resource Operating Partners, L.P. (as successor to Alliance Resource GP, LLC) and various investors	8-K	000-26823 08928968	10.2	07/01/2008	
10.31(1)	Third Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 09647063	10.52	03/02/2009	
10.32(1)	Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan dated as of January 1, 2011	10-K	000-26823 11645603	10.40	02/28/2011	
10.33(1)	Second Amendment to the Amended and Restated Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	10-K	000-26823 09647063	10.53	03/02/2009	
10.34(1)	Amended and Restated Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors dated as of January 1, 2011	10-K	000-26823 11645603	10.42	02/28/2011	
10.35	Amendment No. 2 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association, dated April 13, 2009	10-Q	000-26823 09811514	10.1	05/08/2009	
10.36(2)	Agreement for the Supply of Coal, dated August 20, 2009 between Tennessee Valley	10-Q	000-26823	10.2	11/06/2009	

	Authority and Alliance Coal, LLC		091164883		
10.37	Amended and Restated Charter for the Compensation Committee of the Board of Directors dated February 23, 2010.	10-K	000-26823 10638795	10.49	02/26/2010

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Exhibit Number	Exhibit Description	Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*