ALLIANCE RESOURCE PARTNERS LP
Form 10-K
March 01, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2012

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE TRANSITION PERIOD FROM TO
COMMISSION FILE NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE	**73-1564280**
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(IRS EMPLOYER IDENTIFICATION NO.)

1717 SOUTH BOULDER AVENUE, SUITE 400, TULSA, OKLAHOMA 74119
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND ZIP CODE)
(918) 295-7600
(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

Securities registered pursuant to Section 12(b) of the Act: **Common Units representing limited partner interests**

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	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. ý Yes o 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. o Yes ý 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. ý Yes o No

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

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

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 ý Accelerated Filer o Non-Accelerated Filer o Smaller Reporting Company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes ý 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 $1,159,989,064 as of June 29, 2012, 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 March 1, 2013, 36,963,054 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. Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- 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;
- unexpected changes in raw material costs;
- unexpected changes in the availability of skilled labor;
- our ability to maintain satisfactory relations with our employees;
- any unanticipated increases in labor costs, adverse changes in work rules, or unexpected cash payments or projections associated with post-mine reclamation and workers' compensation claims;
- any unanticipated increases in transportation costs and risk of transportation delays or interruptions;
- unexpected 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;

coal market'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;

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

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

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

You should consider the information above when reading any forward-looking statements contained in this Annual Report on Form 10-K; other reports filed by us with the 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, 2012, we had approximately 919.5 million tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. Approximately 204.9 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. White Oak Transactions." In 2012, we sold a record 35.2 million tons of coal and produced a record 34.8 million tons of coal, of which 3.8% was low-sulfur coal, 18.8% was medium-sulfur coal and 77.4% was high-sulfur coal. In 2012, we sold 93.1% of our total tons to electric utilities, of which 98.7% was sold to utility plants with installed pollution control devices. These devices, also known as scrubbers, eliminate substantially all emissions of sulfur dioxide. We classify low-sulfur coal as coal with a sulfur content of less than 1%, medium-sulfur coal as coal with a sulfur content of 1% to 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

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

ARLP 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

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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 1.0001% managing general partner interest in ARLP and the Intermediate Partnership, respectively. AHGP is a Delaware limited partnership that owns and is the controlling member of MGP. AHGP completed its initial public offering ("AHGP IPO") on May 15, 2006 and is listed on the NASDAQ Global Select Market under the ticker symbol "AHGP." AHGP owns, directly and indirectly, 100% of the members' interest of MGP, a 0.001% managing interest in Alliance Coal, the incentive distribution rights ("IDR") in ARLP and 15,544,169 common units of ARLP. The following diagram depicts our organization and ownership as of December 31, 2012:

(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 (the "Exchange Act").

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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 and Forms 3, 4 and 5 for our Section 16 filers (and amendments and exhibits, such as press releases, to such filings) as soon as reasonably practicable after we electronically file with or furnish such material to the SEC. Information on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. 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 coals with varying sulfur and heat contents, which enables us to satisfy the broad range of specifications required by our customers. The following chart summarizes our coal production by region for the last five years.

	Year Ended December 31,				
Regions	**2012**	**2011**	**2010**	**2009**	**2008**
	(tons in millions)				
Illinois Basin	28.4	25.5	23.7	20.7	20.3
Central Appalachian	1.9	2.5	2.3	2.6	3.2
Northern Appalachian	4.5	2.8	2.9	2.5	2.9
Total	34.8	30.8	28.9	25.8	26.4

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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, 2013, we had 3,002 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 transitioning its 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

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preparation plant in the first quarter of 2009, which has throughput capacity of 1,200 tons of raw coal per hour. Warrior's production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. In 2011, Warrior acquired the Richland No. 9 Mine ("Richland") located near the Warrior complex. Production from Richland, which began in January 2012, is processed through Warrior's preparation plant, and is expected to be exhausted in 2014.

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

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

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

Gibson County Coal is constructing the Gibson South mine, also located near the city of Princeton in Gibson County, Indiana. The Gibson South mine will be an underground mine and will utilize continuous mining units employing room-and-pillar mining techniques to produce medium-sulfur coal. The Gibson South mine's preparation plant will have throughput capacity of 1,800 tons of raw coal per hour. Production from Gibson South mine will be shipped by truck on U.S. and state highways or transported by rail from the Gibson North rail loadout facility directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge delivery. Construction of the mine began in 2011, and we expect production to begin in the fourth quarter of 2014 and annual production to reach approximately 3.0 to 3.5 million tons in 2015 and approximately 5.2 million tons beginning in 2016. Capital expenditures required to develop the Gibson South mine are estimated to be in the range of approximately $200.0 million to $210.0 million, of which approximately $47.5 million has been incurred as of December 31, 2012. These amounts exclude capitalized interest and capitalized mine development costs associated with incidental production. (For more information about mine development costs, please read "Mine Development Costs" under "Item 8. Financial Statements and Supplementary Data Note 2. Summary of Significant Accounting Policies.")

River View Complex. In April 2006, we acquired River View Coal, LLC ("River View"), which controlled coal reserves located in Union County, Kentucky, from ARH. In July 2007, we began

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construction of an underground mining complex to access the reserves. Production began in August 2009. River View utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. River View's preparation plant has throughput capacity of 1,800 tons of raw coal per hour. Coal produced from the River View mine is transported by overland belt to a barge loading facility on the Ohio River.

Sebree Mining Complex. On April 2, 2012, we acquired substantially all of Green River Collieries, LLC's assets related to its coal mining business and operations located in Webster and Hopkins Counties, Kentucky, including the Onton 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 the Sebree Mining complex is transported by overland belt to a barge loading facility on the Green River for shipment to customers, or is shipped via truck on U.S. and state highways directly to customers.

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

Central Appalachian Operations

Our Central Appalachian mining operations are located in eastern Kentucky. As of February 1, 2013, we had 477 employees, and we operate two mining complexes in Central Appalachia.

Pontiki Complex. The Pontiki complex is located near the city of Inez in Martin County, Kentucky. We constructed the mine in 1977. Our subsidiary, Pontiki Coal, LLC ("Pontiki"), 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- and medium-sulfur coal. The preparation plant has throughput capacity of 900 tons of raw coal per hour. Coal produced from the mine is shipped via the NS railroad directly to customers or to various transloading facilities on the Ohio River for barge deliveries, or by truck via U.S. and state highways directly to customers or to various docks on the Big Sandy River for barge deliveries. The complex was idled on August 29, 2012 following a closure order affecting the surface facilities by the Mine Safety and Health Administration ("MSHA"). Operations resumed on November 25, 2012.

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 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 will be transitioned by the end of 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 2012 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.

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Northern Appalachian Operations

Our Northern Appalachian mining operations are located in Maryland and West Virginia. As of February 1, 2013, we had 612 employees, and we operate two mining complexes in Northern Appalachia. We also control undeveloped reserves in West Virginia and Pennsylvania.

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

Tunnel Ridge Complex. Our subsidiary, Tunnel Ridge, LLC ("Tunnel Ridge"), operates the Tunnel Ridge mine, an underground, longwall mine in the Pittsburgh No. 8 coal seam, located near Wheeling, West Virginia. Tunnel Ridge began construction of the mine and related facilities in 2008. Development mining began in 2010, and we had incidental production of approximately 268,000 tons in 2011 as development mining continued. Longwall mining operations began at Tunnel Ridge in the second quarter of 2012 (mid-May). The mine produced just over 2.0 million tons in 2012 and we expect annual production to ultimately reach approximately 5.8 million tons. Coal produced from the Tunnel Ridge mine is transported by conveyor belt to a barge loading facility on the Ohio River. Through an agreement with a third-party, Tunnel Ridge has the ability to transload coal from barges for rail shipment on Wheeling and Lake Erie Railway. Capital expenditures required for development of Tunnel Ridge totaled approximately $280.0 million. This amount excludes 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.")

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

Other Operations

Mt. Vernon Transfer Terminal, LLC

Our subsidiary, Mt. Vernon, leases land and operates a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Coal is delivered to Mt. Vernon by both rail and truck. The terminal has a capacity of

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8.0 million tons per year with existing ground storage of approximately 60,000 to 70,000 tons. During 2012, the terminal loaded approximately 1.1 million tons for customers of Pattiki, Gibson and Elk Creek.

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 2012, we sold approximately 255,000 tons classified as brokerage coal.

Alliance WOR Processing, LLC

In September 2011, we completed a series of transactions with White Oak related to the development of White Oak Mine No. 1 near the city of McLeansboro, Illinois, which is under construction and will be an underground longwall mining operation producing high-sulfur coal from the Herrin No. 6 seam. Initial production from the continuous miner development units is expected to begin in 2013, and longwall mining is expected to begin in 2014. As part of the White Oak transaction, our subsidiary, Alliance WOR Processing, LLC ("WOR Processing"), contracted with White Oak to construct, own, and operate the coal handling and processing facilities associated with the Mine No. 1 mine, which will have the capacity to process 2,000 tons of raw coal per hour. White Oak will have the ability to ship production from the Mine No. 1 mine via rail directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. WOR Processing also has an equity investment in White Oak. For more information about the White Oak transactions, please read "Item 8. Financial Statements and Supplementary Data Note 12. White Oak Transactions."

Alliance Resource Properties, LLC

Alliance Resource Properties owns coal reserves that it leases to certain of our subsidiaries that operate our mining complexes. In September 2011, Alliance Resource Properties' subsidiary, Alliance WOR Properties, LLC ("WOR Properties"), acquired from our affiliate White Oak the rights to approximately 204.9 million tons of proven and probable high-sulfur coal reserves, and leased those reserves back to White Oak. Approximately 105.2 million tons of those reserves are currently being developed for future mining by White Oak. Once coal sales begin from the mine, White Oak will pay WOR Properties earned royalties and during the period beginning January 1, 2015 and ending December 31, 2034 will pay WOR Properties a fully recoupable minimum monthly royalty of $1.625 million. WOR Properties anticipates receiving royalties from White Oak beginning in 2013 with the start-up of incidental production from White Oak's mine development.

Matrix Group

Our subsidiaries, Matrix Design Group, LLC ("Matrix Design") and Alliance Design Group, LLC ("Alliance Design") (collectively, "Matrix Group"), provide a variety of mine products and services for our mining operations and to unrelated parties. We acquired this business in September 2006. Matrix Group's products and services include design and installation of underground mine hoists for transporting employees and materials in and out of mines; design of systems for automating and controlling various aspects of industrial and mining environments; and design and sale of mine safety equipment, including its miner and equipment tracking and proximity detection systems. In 2012, our financial results were not significantly impacted by Matrix Group's activities.

Additional Services

We develop and market additional services in order to establish ourselves as the supplier of choice for our customers. Examples of the kind of services we have offered to date include ash and scrubber sludge removal, coal yard maintenance and arranging alternate transportation services. Historically, and in 2012, revenues from these services have been immaterial. In addition, our affiliate, Mid-America Carbonates, LLC ("MAC"), which is a joint venture with White County Coal, manufactures and sells rock dust to us and to unrelated parties. In 2012, 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 2012, approximately 94.2% and 94.3% 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 2013 to 2020. As of January 28, 2013, our nominal commitment under long-term contracts was approximately 38.5 million tons in 2013, 30.7 million tons in 2014, 23.4 million tons in 2015 and 18.7 million tons in 2016. The commitment of coal under contract is an approximate number because a limited number of our contracts contain provisions that could cause the nominal commitment to increase or decrease; however, the overall variance to total committed sales is minimal. The contractual time commitments for customers to nominate future purchase volumes under these contracts are typically sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal commitment can otherwise change because of reopener provisions contained in certain of these long-term contracts.

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

Reliance on Major Customers

Our two largest customers in 2012 were Louisville Gas and Electric Company and Tennessee Valley Authority. During 2012, we derived approximately 28.5% of our total revenues from these two customers and at least 10.0% of our total revenues from each of the two. For more information about these customers, please read "Item 8. Financial Statements and Supplementary Data Note 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., James River Coal Company, Murray Energy, Inc., Foresight Energy LLC and Peabody Energy Corp. Some of these coal producers are larger and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in the Illinois Basin, Central Appalachian and Northern Appalachian regions. The prices we are able to obtain for our coal are primarily linked to coal consumption patterns of domestic electricity generating utilities, which in turn are influenced by economic activity, government regulations, weather and technological developments. Additionally, we export a portion of our coal into the international coal markets. The prices we are able to obtain for our export coal are influenced by a number of factors, such as global economic conditions, weather patterns and political instability, among others. Further, coal competes with other fuels such as petroleum, natural gas, nuclear energy and renewable energy sources for electrical power generation. Over time, costs and other factors, such as safety and environmental considerations, may affect the overall demand for coal as a fuel. For additional information, please see "Item 1A. Risk Factors." As the price of domestic coal increases, we may also begin to compete with companies that produce coal from one or more foreign countries.

Transportation

Our coal is transported to our customers by rail, truck and barge. Depending on the proximity of the customer to the mine and the transportation available for delivering coal to that customer, transportation costs can range from 2.9% to 48.0% of the total delivered cost of a customer's coal. As a consequence, the availability and cost of transportation constitute important factors in the marketability of coal. We believe our mines are located in favorable geographic locations that minimize transportation costs for our customers, and in many cases we are able to accommodate multiple transportation options. Typically, our customers pay the transportation costs from the mining complex to the destination, which is the standard practice in the industry. Approximately 52.3% of our 2012 sales volume was initially shipped from the mines by rail, 13.1% was shipped from the mines by truck and 34.6% was shipped from the mines by barge. In 2012, the largest volume transporter of our coal shipments was the CSX railroad which moved approximately 33.0% of our tonnage over its rail system. The practices of, and rates set by, the transportation company serving a particular mine or customer may affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mine.

Regulation and Laws

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

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

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

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

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

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. Applications for permits require extensive engineering and data analysis and presentation, and must address a variety of environmental, health and safety matters associated with a proposed mining operation. These matters include the manner and sequencing of coal extraction, the storage, use and disposal of waste and other substances and other 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 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.

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.

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Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since the Federal Coal Mine Health and Safety Act of 1969 ("CMHSA") was adopted. The Federal Mine Safety and Health Act of 1977 ("FMSHA"), and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards of the CMHSA, and imposed extensive and detailed safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations, and numerous other matters. The MSHA monitors and rigorously enforces compliance with these federal laws and regulations. In addition, most of the states where we operate have state programs for mine safety and health regulation and enforcement. Federal and state safety and health regulations affecting the coal mining industry are perhaps the most comprehensive and rigorous system in the United States for protection of employee safety and have a significant effect on our operating costs. Although many of the requirements primarily impact underground mining, our competitors in all of the areas in which we operate are subject to the same laws and regulations.

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

The Federal Mine Improvement and New Emergency Response Act of 2006 ("MINER Act") significantly amended the FMSHA, imposing more extensive and stringent compliance standards, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection, and enforcement activities. Following the passage of the MINER Act, MSHA has issued new or more stringent rules and policies on a variety of topics, including:

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

MSHA continues to interpret and implement various provisions of the MINER Act, along with introducing new proposed regulations and standards. Among these new proposed regulations is MSHA's proposed rule titled "Lowering Miner's Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors." The proposed rule would require a 50% reduction in the allowable respirable coal mine dust exposure limits and require each operation to significantly increase the number of respirable coal mine dust samples taken. The rule would also increase oversight by MSHA regarding coal mine dust and ventilation issues at each mine, including the approval process for ventilation plans at each mine. Federal legislation was enacted in 2011 to prevent MSHA from implementing or enforcing the proposed rule until such time as the General Accounting Office ("GAO") performed an independent assessment of MSHA's data and methodology used in creating the rule. Although the GAO performed this assessment in 2012, MSHA has not yet announced when the final rule will be promulgated.

Additionally, in 2012, MSHA promulgated a final rule to expand the job responsibilities of mine employees who perform pre-shift and on-shift examinations of working areas within underground coal

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mines. These employees examine the mine for hazards and to verify that atmospheric and ventilation conditions are in compliance with regulations. Under MSHA's new rule, examiners are now also required to examine for, and record the presence of, certain types of regulation violations for which MSHA inspectors would be inspecting.

Effective March 25, 2013, MSHA will begin implementing its recently released Pattern of Violation ("POV") regulations under the FMSHA. Under this new POV regulation, MSHA will eliminate the ninety (90) day window, during which mine operators meeting certain initial POV screening criteria could take corrective action and engage in mitigation efforts to avoid being placed on POV status. Additionally, MSHA will make POV determinations based upon enforcement actions as issued, rather than enforcement actions that have been rendered final following the opportunity for administrative or judicial review. If a mine operator is placed on POV status, MSHA will thereafter issue an order withdrawing miners from the area affected by any enforcement action designated by MSHA as posing a significant and substantial, or S&S, hazard to the health and/or safety of miners. Further, the mine operator can be removed from POV status only upon: (1) a complete inspection of the entire mine with no S&S enforcement actions issued by MSHA or (2) no POV-related withdrawal orders being issued by MSHA within ninety (90) days following the mine operator being placed on POV status.

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. Other states may pass similar legislation in the future.

Some of the costs of complying with existing regulations and implementing new safety and health regulations may be passed on to our customers. Although we are unable to quantify the full impact, implementing and complying with these new state and federal safety laws and regulations have had, and are expected to continue to have, an adverse impact on our results of operations and financial position.

Black Lung Benefits Act

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

Revised BLBA regulations took effect in January 2001, relaxing the stringent award criteria established under previous regulations and thus potentially allowing more 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.

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The Patient Protection and Affordable Care Act ("PPACA") 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.

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 ("AMD") control on a statewide basis.

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

The U.S. Office of Surface Mining Reclamation ("OSM") published in November 2009 an Advance Notice of Proposed Rulemaking and announced 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. To date, the OSM has not proposed any new SBZ rule. In January 2013, the environmental groups reopened the litigation against OSM for failure to abide by the terms of the March 2010 settlement. We are unable to predict the impact, if any, of these actions by the OSM, although the actions potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities near streams, and additional enforcement actions. The requirements of the revised SBZ rule, if adopted, will likely be stricter than the prior SBZ rule and may adversely affect our business and operations.

Bonding Requirements

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

As of December 31, 2012, we had approximately $76.0 million in surety bonds outstanding to secure the performance of our reclamation obligations.

Air Emissions

The CAA and similar state and local laws and regulations regulate emissions into the air and affect coal mining operations. The CAA directly impacts our coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, achieve certain emissions standards, or implement certain work practices on sources that emit various air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants and other coal-burning facilities. There have been a series of federal rulemakings focused on emissions from coal-fired electric generating facilities. In addition, there is pending litigation to force the U.S. Environmental Protection Agency ("EPA") to list coal mines as a category of air pollution sources that endanger public health or welfare under Section 111 of the CAA and establish standards to reduce emissions from new or modified coal mine sources of methane and other emissions. Installation of additional emissions control technology and any additional measures required under the laws, as well as regulations promulgated by the EPA, will make it more costly to operate coal-fired power plants and 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 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 2012, we sold 93.1% of our total tons to electric utilities, of which 98.7% was sold to utility plants with installed pollution control devices. These requirements would not be supplanted by a replacement rule for the Clean Air Interstate Rule ("CAIR"), discussed below.

The EPA has promulgated rules, referred to as the "Nitrogen Oxide SIP Call," that, among other things, require coal-fired power plants in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. As a result of the program, many power plants have been or will be required to install additional emission control measures, such as selective catalytic reduction devices. Installation of additional emission control measures will make it more costly to operate coal-fired power plants, potentially making coal a less attractive fuel.

Additionally, in March 2005, the EPA issued the final CAIR which would have permanently capped nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. On July 11, 2008, the D.C. Circuit Court of Appeals vacated CAIR, but on petition for rehearing, the court retracted its decision and remanded the rule to the EPA for further consideration. This remand had the effect of leaving the rule in place while the EPA evaluated possible changes to the rule to correct the defects identified in the court's original opinion. In June 2011, the EPA finalized the Cross State Air Pollution Rule ("CSAPR"), a replacement rule for CAIR, which would have required 28 states in the Midwest and eastern seaboard to reduce power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. However, on August 21, 2012, the D.C. Circuit Court of Appeals vacated CSAPR, finding EPA exceeded its statutory authority under the CAA and striking down EPA's decision to require a federal implementation plan, rather than state implementation plans ("SIPs"), to implement mandated reductions. In its ruling, the Court ordered the EPA to continue administering CAIR but proceed expeditiously to promulgate a replacement rule for CAIR. The Court subsequently denied EPA's petition for an en banc hearing on CSAPR. It is possible that a future replacement rule for CAIR could lead to the premature retirement of coal-fired electric generating units, which could in turn reduce the demand for coal.

In March 2005, the EPA finalized the Clean Air Mercury Rule ("CAMR"), which established a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. On February 8, 2008, the D.C. Circuit Court of Appeals vacated CAMR for further consideration by the EPA. On December 16, 2011, the EPA signed a rule to establish a national standard to reduce mercury and other toxic air pollutants from coal and oil-fired power plants, referred to as the EPA's Mercury and Air Toxics Standards ("MATS"). MATS imposes stricter limitations on mercury emissions from power plants than the vacated CAMR. States, companies and industry groups filed petitions to reconsider the rule and petitions for review in the D.C. Circuit Court of Appeals. EPA agreed on July 20, 2012 to reconsider the standards for new source emissions in the rule, but not other aspects of the rule. Legal challenges in the D.C. Circuit Court of Appeals are still pending. If upheld by the Court, MATS will force generators to make capital investments to retrofit power plans and will also likely lead to the premature retirement of a number of older coal-fired generating units. The retirements are likely to reduce the demand for coal.

The EPA also issued a final rule on January 31, 2013 requiring Utility Boiler Maximum Achievable Control Technology standards ("Boiler MACT") for power plants, which requires 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 for several classes of boilers and process heaters, including large coal-fired boilers and process heaters. Like MATS, Boiler MACT imposes stricter limitations on mercury emissions than those vacated in CAMR. We anticipate legal challenges to Boiler MACT. However, if Boiler MACT is upheld, EPA estimates the rule will affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. Some owners will make capital expenditures to retrofit boilers and process heaters, while a number of boilers and process heaters will be prematurely retired. The retirements are likely to reduce the demand for coal.

The EPA is required by the CAA to periodically re-evaluate the available health effects information to determine whether the national ambient air quality standards ("NAAQS") should be revised. Pursuant to this process, the EPA has adopted more stringent NAAQS for fine particulate matter, 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. Attainment dates for the new standards range between 2013 and 2030, depending on the severity of the non-attainment. In July 2009, the U.S. Court of Appeals for the District of Columbia vacated part of a rule implementing the ozone NAAQS and remanded certain other aspects of the rule to the EPA for further consideration. On July 19, 2012, the EPA released two separate risk assessments for ozone NAAQS recommending a lower ozone standard. EPA has announced plans to release a new ozone NAAQS by August 2013. That 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 nitrogen oxides, which are precursors to ozone formation, 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.

The EPA's regional haze program is designed to protect and to improve visibility at and around national parks, national wilderness areas and international parks. Under the EPA program, states are required to develop SIPs to improve visibility. Typically, these plans call for reductions in SO2 and NOx emissions from coal-fueled electric plants. In recent cases, EPA has decided to negate the SIPs and impose stringent requirements through Federal Implementation Plans ("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. In addition, the EPA's new source review program under certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly increase emissions, to install the more stringent air emissions control equipment. These requirements could limit the demand for coal in some locations.

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The Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the new source review provisions of the CAA. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending, and still more lawsuits may be filed. 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 "greenhouse gas" or "GHG." Future regulation of greenhouse gas emissions in the U.S. could occur pursuant to future U.S. treaty commitments, new domestic legislation or regulation by the EPA. President Obama has expressed support for a mandatory cap and trade program to restrict or regulate emissions of greenhouse gases and Congress has recently considered various proposals to reduce greenhouse gas emissions, and it is possible federal legislation could be adopted in the future. Internationally, the Kyoto Protocol, which set binding emission targets for developed countries (including the United States but has not been ratified by the United States, and Canada officially withdrew from its Kyoto commitment in 2012) 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 greenhouse gas emissions that could, in turn, have a global impact on the demand for coal. Also, many states, regions and governmental bodies have adopted greenhouse gas initiatives and have or are considering the imposition of fees or taxes based on the emission of greenhouse gases by certain facilities, including coal-fired electric generating facilities. Depending on the particular regulatory program that may be enacted, at either the federal or state level, the demand for coal could be negatively impacted which would have an adverse effect on our operations.

Even in the absence of new federal legislation, the EPA has begun to regulate greenhouse gas emissions pursuant to the CAA based on the U.S. Supreme Court's 2007 decision in *Massachusetts v. EPA* that the EPA has authority to regulate greenhouse gas emissions. In 2009, the EPA issued a final rule declaring that greenhouse gas emissions, including carbon dioxide and methane, endanger public health and welfare and that greenhouse gases emitted by motor vehicles contribute to that endangerment ("Endangerment Finding").

In May 2010, the EPA issued its final "tailoring rule" for greenhouse gas emissions, a policy aimed at shielding small emission sources from CAA permitting requirements. The EPA's rule phases in various greenhouse-gas-related permitting requirements beginning in January 2011. Beginning July 1, 2011, the EPA requires facilities that must already obtain new source review permits for other pollutants to include greenhouse gases in their permits for new construction projects that emit at least 100,000 tons per year of greenhouse gases and existing facilities that increase their emissions by at least 75,000 tons per year.

In March of 2012, EPA proposed New Source Performance Standards ("NSPS") for CO2 emissions from new fossil fuel-fired power plants. The proposal requires new coal units to meet a CO2 emissions standard of 1,000 lb CO2/MWh, which is equivalent to the CO2 emitted by a natural gas combined cycle unit. Legal challenges to the proposed NSPS have been filed; more legal challenges are expected once EPA issues a final rule. The timing for promulgating a final rule is unknown, but latest reports are that it will be finalized by mid-year 2013. If the proposed rule is finalized as currently drafted, the rule will likely prevent new coal fired power plants from being built and reduce the demand for coal in the future. EPA has indicated that it may propose NSPS for existing and modified coal plants at some time in the future, which could lead to the premature retirement of coal-fired generating units and reduce the demand for coal.

On June 28, 2010, the EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule requiring all stationary sources that emit more than 25,000 tons of greenhouse gases per year to collect and

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report to the EPA data regarding such emissions. This suite of greenhouse gas 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 greenhouse gas emissions on January 1, 2011 and began reporting to the EPA in 2012.

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 greenhouse gas 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 greenhouse gas 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 greenhouse gas emissions have been appealed to the EPA's Environmental Appeals Board. In addition, over thirty states have currently adopted "renewable energy standards" or "renewable portfolio standards," which encourage or require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect our current and prospective customers, they may reduce the demand for coal-fired power, and may affect long-term demand for our coal. Finally, a federal appeals court allowed a lawsuit pursuing federal common law claims to proceed against certain utilities on the basis that they may have created a public nuisance due to their emissions of carbon dioxide, while a second federal appeals court dismissed a similar case on procedural grounds. The U.S. Supreme Court recently overturned that decision on June 20, 2011, holding that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, but despite this favorable ruling, tort-type liabilities remain a concern.

It is possible that future international, federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, or otherwise adversely affect our operations and demand for our products, which could have a material adverse effect on our business, financial condition and results of operations.

Water Discharge

The Federal Clean Water Act ("CWA") and similar state and local laws and regulations affect coal mining operations by imposing restrictions on effluent discharge into waters and the discharge of dredged or fill material into the waters of the U.S. Regular monitoring, as well as compliance with reporting requirements and performance standards, is a precondition for the issuance and renewal of permits governing the discharge of pollutants into water. Section 404 of the CWA imposes permitting and mitigation requirements associated with the dredging and filling of wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary permits required under CWA Section 404 as it has traditionally been interpreted by the responsible agencies. However, mitigation requirements under existing and possible future "fill" permits may vary considerably. For that reason, the setting of post-mine asset retirement obligation accruals for such mitigation projects is difficult to ascertain with certainty and may increase in the future. Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of such permitting requirements.

The U.S. Army Corps of Engineers ("Corps of Engineers") maintains two permitting programs under CWA Section 404 for the discharge of dredged or fill material: one for "individual" permits and a more streamlined program for "general" permits. In June 2010 the Corps of Engineers suspended the use of "general" permits under Nationwide Permit 21 ("NWP 21") in the Appalachian states. On February 21, 2012, the Corps of Engineers reissued the final 2012 NWP 21. The Center for Biological Diversity later filed a notice of intent to sue the Corps of Engineers based on allegations the 2012 NWP 21 program violated the Endangered Species Act. Our coal mining operations typically require Section 404 permits to authorize activities such as the creation of slurry ponds and stream impoundments. The CWA authorizes the EPA to review Section 404 permits issued by the Corps of Engineers, and in 2009, the EPA began reviewing Section 404 permits issued by the Corps of Engineers for coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

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

The EPA also has statutory "veto" power over a Section 404 permit if the EPA determines, after notice and an opportunity for a public hearing, that the permit will have an "unacceptable adverse effect." On January 14, 2011, the EPA exercised its veto power to withdraw or restrict the use of a previously issued permit for Spruce No. 1 Surface Mine in West Virginia, which is one of the largest surface mining operations ever authorized in Appalachia. This action was the first time that such power was exercised with regard to a previously permitted coal mining project. A challenge to the EPA's exercise of this authority made in the federal District Court in the District of Columbia and on March 23, 2012, the Court ruled that the EPA lacked the statutory authority to invalidate an already issued Section 404 permit retroactively. This decision is currently on appeal. Any future use of the EPA's Section 404 "veto" power could create uncertainly with regard to our continued use of current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting our coal revenues.

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

Hazardous Substances and Wastes

The Federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), otherwise known as the "Superfund" law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for the release of hazardous substances may be subject to joint and several liability under CERCLA for the costs of cleaning up releases of hazardous substances and natural resource damages. Some products used in coal mining operations generate waste containing hazardous substances. We are currently unaware of any material liability associated with the release or disposal of hazardous substances from our past or present mine sites.

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

On June 21, 2010, the EPA released a proposed rule to regulate the disposal of certain coal combustion by-products ("CCB"). The proposed rule sets forth two proposed very different approaches for regulating CCB under RCRA. The first option calls 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 utilizes Subtitle D, which gives the 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 the EPA to compel the EPA to take action on the proposed rule. If CCB were re-classified as hazardous waste, regulations would likely restrict ash disposal, provide specifications for storage facilities, require groundwater testing and impose restrictions on storage locations, which could increase our customers' operating costs and potentially reduce their ability to purchase coal. In addition, contamination caused by the past disposal of CCB, including coal ash, may lead to material liability to our customers under RCRA or other federal or state laws and potentially reduce the demand for coal. Although it is not currently possible to predict how such regulations would impact our operations or those of our customers, the regulation of CCB as hazardous waste could result in increased disposal and compliance costs, which could result in decreased demand for our products.

Other Environmental, Health And Safety Regulations

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

Employees

To conduct our operations, as of February 1, 2013, we employed 4,345 full-time employees, including 4,091 employees involved in active mining operations, 86 employees in other operations, and 168 corporate employees. Our work force is entirely union-free. We believe that relations with our employees are generally good.

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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 ("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, 2012 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*."

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;
- 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.

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

- the level of our capital expenditures;
- the cost of acquisitions, if any;
- our debt service requirements and restrictions on distributions contained in our current or future debt agreements;
- fluctuations in our working capital needs;
- unavailability of financing resulting in unanticipated liquidity restraints;
- our ability to borrow under our credit agreement to make distributions to our unitholders; and
- the amount, if any, of cash reserves established by our managing general partner, in its discretion, for the proper conduct of our business.

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

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

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

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

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

As of December 31, 2012, AHGP owned 15,544,169 of our common units. AHGP also owns our managing general partner. In the future, AHGP may sell some or all of these units or it may distribute our common units to the holders of its equity interests and those holders may dispose of some or all of these units. The sale or disposition of a substantial number of our common units in the public markets could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. We do not know whether any such sales would be made in the public market or in private placements, nor do we know what impact such potential or actual sales would have on our unit price in the future.

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

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

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

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

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

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Our unitholders do not elect our managing general partner or vote on our managing general partner's officers or directors. As of December 31, 2012, AHGP owned approximately 42.2% of our outstanding units, a sufficient number to block any attempt to remove our 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, 2012, AHGP held approximately 42.2% 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.

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."

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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.

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").

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.

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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.

Economic conditions in a number of industries served by our primary customers substantially deteriorated in recent years and reduced the demand for coal. Although global industrial activity has recovered in 2010 and 2011 from 2009 levels, such activity weakened in 2012 and the outlook is uncertain, especially for Europe, which continues to be affected by sovereign debt issues, and the United States, which may increase taxes and cut government spending to address deficits. In addition, in 2008 and 2009, financial markets in the U.S., Europe and Asia also experienced unprecedented turmoil and upheaval. This was characterized by extreme volatility and declines in security prices, severely diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the U.S. federal government and other governments. Although we cannot predict the impacts, renewed weakness in the economic conditions of any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- the demand for electricity in the U.S. may not fully recover or may decline if economic conditions deteriorate, which may negatively impact the revenues, margins and profitability of our business;
- any inability of our customers to raise capital could adversely affect their ability to honor their obligations to us; and
- our future ability to access the capital markets may be restricted as a result of future economic conditions, which could materially impact our ability to grow our business, including development of our coal reserves.

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

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

- the supply of and demand for domestic and foreign coal;
- weather conditions;
- 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.

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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 large coal producers and many small coal producers in various regions of the U.S. for domestic coal sales. The industry has undergone significant consolidation over the last decade. This consolidation has led to several competitors having significantly larger financial and operating resources than us. In addition, we compete to some extent with western surface coal mining operations that have a much lower per ton cost of production and produce low-sulfur coal. Over the last 20 years, growth in production from western coal mines has substantially exceeded growth in production from the east. Declining prices from an oversupply of coal in the market could reduce our revenues and our cash available for distribution.

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

The domestic electric utility industry accounts for approximately 93.0% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as alternative sources of energy. For example, the relatively low price of natural gas has resulted, in some instances, in utilities increasing natural gas consumption while decreasing coal consumption. Future environmental regulation of greenhouse gas 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 the EPA in the last four years, such as CSAPR and MATS, have led to the premature retirement of coal-fired generating units and a significant reduction in the amount of coal-fired generating capacity in the United States. While CSAPR was struck down by the Federal Court of Appeals for the D.C. Circuit and many of the other rules, including MATS, are currently being legally challenged by states and private parties, utilities and other generators of electricity made retirement decisions and retired some units based upon the EPA's proposed and finalized rules. In addition, the EPA has proposed regulations to govern the disposal of coal ash and other coal combustion residuals that include the possibility of categorizing such CCB as a hazardous waste. 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 greenhouse gas 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, the EPA published the "endangerment finding" asserting that emissions of carbon dioxide and other greenhouse gases present an endangerment to public health and the environment, and the EPA has begun to regulate greenhouse gas emissions pursuant to the CAA. The EPA has proposed to regulate greenhouse gas emissions from new power plants. The standard proposed is a natural gas standard and would effectively prevent construction of new coal fired power plants. The EPA has not proposed to regulate greenhouse gas emissions from modified or existing power plants, but could attempt to do so in the future. In addition, it is possible more federal legislation or regulations could be adopted in the future to restrict greenhouse gas emissions, as President Obama has expressed support for a mandatory cap and trade program to restrict or regulate emissions of greenhouse gases and Congress has recently considered various proposals to reduce greenhouse gas emissions. Many states and regions have adopted greenhouse gas initiatives. Also, there have been numerous protests of, and challenges to, the permitting of new coal-fired power plants by environmental organizations and state regulators for concerns related to greenhouse gas emissions. Please read "Item 1. Business Regulation and Laws *Air Emissions*" and " *Carbon Dioxide Emissions*."

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

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

In 2004, eight states and New York City sued five electric utility companies in *Connecticut v. American Electric Power Co.* These defendants were chosen as allegedly the five-largest carbon dioxide emitters in the U.S., through their fossil-fuel-fired electric power plants. 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. Plaintiffs sued both on their own behalf to protect state-owned property and on behalf of their citizens and residents to protect public health and well-being. On September 21, 2009, on appeal of the trial court's dismissal of the case, the Second Circuit issued a ruling holding that the district court erred in dismissing the complaints on political question grounds, that all of the plaintiffs have standing and that plaintiffs validly stated claims under the federal common law on nuisance. In June 2011, the U.S. Supreme Court issued a unanimous decision reversing the Second Circuit's decision and 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 on remand. 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.

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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 2012, we sold approximately 94.2% 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.

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. 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 2012, we derived approximately 28.5% of our total revenues from two customers and at least 10.0% of our 2012 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.

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

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

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

These conditions have had, and can be expected in the future to have, a significant impact on our operating results. Prolonged disruption of production at any of our mines would result in a decrease in our revenues and profitability, which could materially adversely impact our quarterly or annual results.

During October 2012, we completed our annual property and casualty insurance renewal with various insurance coverages effective October 1, 2012. The aggregate maximum limit in the commercial property program is $100.0 million per occurrence, excluding a $1.5 million deductible for property damage, a 90-day waiting period for underground business interruption 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 will not control all of its decisions. Consequently, it may be difficult or impossible for us to cause White Oak to take actions that we believe would be in our or its best interests, and we may be unable to control the amount and timing of cash we will receive from White Oak's operations. Likewise, the White Oak board may control the timing of certain capital investments we are committed to making in White Oak. The lack of control over timing of such revenues and costs could have an adverse impact on the benefits we expect to achieve from the White Oak transactions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We plan to fund capital expenditures for our current growth projects with existing cash balances, future cash flows from operations, borrowings under revolving credit facilities and cash provided from the issuance of debt or equity. Our funding plans may, however, be negatively impacted by numerous factors, including higher than anticipated capital expenditures or lower than expected cash flow from operations. In addition, we may be unable to refinance our current revolving credit facility when it expires or obtain adequate funding prior to expiry because our lending counterparties may be unwilling or unable to meet their funding obligations. Furthermore, additional growth projects and expansion opportunities may develop in the future which could also require significant amounts of financing that may not be available to us on acceptable terms or in the amounts we expect, or at all.

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

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

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because we deplete our reserves as we mine coal, our future success and growth depend, in

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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 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 to 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, 2012, our total long-term indebtedness outstanding was $773.0 million. Our leverage may:

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

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

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

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

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

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

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

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

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

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

We are party to a number of legal proceedings incident to our normal business activities. There is the potential that an individual matter or the aggregation of multiple matters could have an adverse effect on our cash flows, results of operations or financial position. Please see "Item 8. Financial Statements and Supplementary Data Note 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, or 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 limited partnerships 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 amount and the target distribution amounts may be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced and the value of our common units could be negatively impacted.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. One such legislative proposal would 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. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the qualifying income requirement to be treated as a partnership for U.S. federal income tax purposes.

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

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

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 due from you with respect to that 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 decrease 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.

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

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

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

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

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

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

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

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

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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.

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, 2012, we had approximately 919.5 million tons of coal reserves. Approximately 204.9 million tons of those reserves, located in Hamilton County, Illinois, are leased to White Oak and are not reflected in the operations table below. All of the estimates of reserves presented in the tables below are of proven and probable reserves (as defined below) and adhere to the standards described in U.S. Geological Survey ("USGS") Circular 831 and USGS Bulletin 1450-B. For information on the locations of our mines, please read "Mining Operations" under "Item 1. Business."

The following table sets forth reserve information at December 31, 2012, about our mining operations:

			Proven and Probable Reserves Pounds $S0_2$ per MMBTU				**Reserve Assignment**		**Reserve Control**	
Operations	**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										
Dotiki (KY)	Underground	12,100			47.0	47.0	47.0		19.0	28.0
Warrior (KY)	Underground	12,600			123.7	123.7	84.0	39.7	31.1	92.6
Hopkins (KY)	Underground	12,200			29.7	29.7	14.7	15.0	5.0	24.7
	/ Surface	11,500			7.8	7.8	7.8		7.8	
River View (KY)	Underground	11,600			127.2	127.2	127.2		13.2	114.0
Onton (KY)	Underground	11,850			41.4	41.4	41.4		0.6	40.8
Sebree (KY)	Underground	11,400			26.2	26.2		26.2		26.2
Pattiki (IL)	Underground	11,500			46.1	46.1	46.1		0.1	46.0
Gibson (North) (IN)	Underground	11,500		9.8	8.7	18.5	18.5		0.1	18.4
Gibson (South) (IN)	Underground	11,500		21.7	45.2	66.9	66.9		20.8	46.1
Region Total				31.5	503.0	534.5	453.6	80.9	97.7	436.8
Central Appalachian Operations										
Pontiki (KY)	Underground	12,900		2.9		2.9	2.9			2.9
MC Mining (KY)	Underground	12,600	10.0	0.5	1.5	12.0	12.0		1.6	10.4
Region Total			10.0	3.4	1.5	14.9	14.9		1.6	13.3
Northern Appalachian Operations										
Mettiki (MD)	Underground	12,900		1.9	5.3	7.2	7.2			7.2
Mountain View (WV)	Underground	12,900		3.2	2.4	5.6	5.6			5.6
Tunnel Ridge (PA/WV)	Underground	12,700			95.7	95.7	95.7			95.7
Penn Ridge (PA)	Underground	12,500			56.7	56.7	56.7			56.7
Region Total				5.1	160.1	165.2	165.2			165.2

Total	10.0	40.0	664.6	714.6	633.7	80.9	99.3	615.3
% of Total	1.4%	5.6%	93.0%	100.0%	88.7%	11.3%	13.9%	86.1%

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The following table sets forth information related to reserves leased to White Oak at December 31, 2012:

			Proven and Probable Reserves Pounds SO_2 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			204.9	204.9	204.9		11.6	193.3

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 $^1/_2$ mile apart and are projected to extend as a $^1/_4$ mile wide belt around each point of measurement and (b) probable reserves is that points of observation are between $^1/_2$ and $1^1/_2$ miles apart and are projected to extend as a $^1/_2$ mile wide belt that lies $^1/_4$ 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 performed an audit of our reserves and calculation methods in August 2010.

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 10.0 million tons of reserves listed as <1.2 pounds of SO2 per million British thermal units ("MMBTU") are 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 control certain leases for coal deposits that are near, but not contiguous to, our primary reserve bases. The tons controlled by these leases are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits are as follows: Dotiki 6.5 million tons, Pattiki 13.5 million tons, Hopkins County Coal 2.5 million tons, River View 22.6 million tons, Onton 7.2 million tons, Sebree Mining 0.2 million tons, Gibson (North) 6.4 million tons, Gibson (South) 4.7 million tons, Warrior 9.5 million tons, Mettiki 1.8 million tons, Tunnel Ridge 2.3 million tons, Penn Ridge 3.4 million tons and Pontiki 11.7 million tons. In addition, there are 64.3 million tons of coal located near the River View complex and 4.6 million tons of coal located near the Dotiki complex, for total non-reserve coal deposits of 161.2 million tons.

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

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Mining Operations

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

Operations	Location	Tons Produced 2012	2011	2010	Transportation	Equipment
		(in millions)				
Illinois Basin Operations						
Dotiki	Kentucky	3.4	3.6	3.9	CSX, PAL, truck, barge	CM
Warrior	Kentucky	5.9	5.4	5.8	CSX, PAL, truck, barge	CM
Hopkins	Kentucky	3.1	3.3	3.3	CSX, PAL, truck, barge	CM
River View	Kentucky	8.6	7.6	5.9	Barge	CM
Onton	Kentucky	1.6			Barge, truck	CM
Pattiki	Illinois	2.4	2.2	1.7	EVWR, barge	CM
Gibson (North)	Indiana	3.4	3.4	3.1	CSX, NS, truck, barge	CM
Region Total		28.4	25.5	23.7		
Central Appalachian Operations						
Pontiki	Kentucky	0.6	1.0	0.9	NS, truck, barge	CM
MC Mining	Kentucky	1.3	1.5	1.4	CSX, truck, barge	CM
Region Total		1.9	2.5	2.3		
Northern Appalachian Operations						
Mettiki	Maryland	0.2	0.2	0.4	Truck, CSX	CM, CS
Mountain View	West Virginia	2.3	2.3	2.4	Truck, CSX	LW, CM
Tunnel Ridge	West Virginia	2.0	0.3	0.1	Barge, WLE	LW, CM
Region Total		4.5	2.8	2.9		
TOTAL		34.8	30.8	28.9		

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
CS - Contour Strip

ITEM 3. LEGAL PROCEEDINGS

We are subject to various types of litigation in the ordinary course of our business. We are not engaged in any litigation that we believe is material to our operations, including without limitation, any litigation relating to our long-term coal supply contracts or under the various environmental protection statutes to which we are subject. 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 15, 2013, the closing market price for the common units was $62.57 per unit. As of February 15, 2013, there were 36,963,054 common units outstanding. There were approximately 36,248 record holders and beneficial owners (held in street name) of common units at December 31, 2012.

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	Low	Distributions Per Unit
1st Quarter 2011	$ 84.10	$ 62.42	$0.890 (paid May 13, 2011)
2nd Quarter 2011	$ 82.89	$ 66.53	$0.9225 (paid August 12, 2011)
3rd Quarter 2011	$ 80.67	$ 61.00	$0.955 (paid November 14, 2011)
4th Quarter 2011	$ 77.00	$ 58.00	$0.990 (paid February 14, 2012)
1st Quarter 2012	$ 83.80	$ 56.69	$1.025 (paid May 15, 2012)
2nd Quarter 2012	$ 64.99	$ 50.42	$1.0625 (paid August 14, 2012)
3rd Quarter 2012	$ 67.10	$ 55.72	$1.085 (paid November 14, 2012)
4th Quarter 2012	$ 66.47	$ 52.21	$1.1075 (paid February 14, 2013)

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 minimum quarterly distribution ("MQD") and common unit arrearages, if any. Our partnership agreement defines the MQD as $0.25 for each full fiscal quarter ($1.00 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 $0.275 per unit, 25% of the amount we distribute in excess of $0.3125 per unit, and 50% of the amount we distribute in excess of $0.375 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, 2012, 2011, 2010, 2009 and 2008.

(in millions, except unit, per unit and per ton data)	Year Ended December 31,				
	2012	2011	2010	2009	2008
Statements of Income					
Sales and operating revenues:					
Coal sales	$ 1,979.4	$ 1,786.1	$ 1,551.5	$ 1,163.9	$ 1,093.1
Transportation revenues	22.0	31.9	33.6	45.7	44.7
Other sales and operating revenues	32.9	25.6	24.9	21.4	18.7
Total revenues	2,034.3	1,843.6	1,610.0	1,231.0	1,156.5
Expenses:					
Operating expenses (excluding depreciation, depletion and amortization)	1,303.3	1,131.8	1,009.9	797.6	801.9
Transportation expenses	22.0	31.9	33.6	45.7	44.7
Outside coal purchases	38.6	54.3	17.1	7.5	23.8
General and administrative	58.8	52.3	50.8	41.1	37.2
Depreciation, depletion and amortization	218.1	160.3	146.9	117.5	105.3
Asset impairment charge	19.0				
Gain from sale of coal reserves					(5.2)
Net gain from insurance settlement and other(1)					(2.8)
Total operating expenses	1,659.8	1,430.6	1,258.3	1,009.4	1,004.9
Income from operations	374.5	413.0	351.7	221.6	151.6
Interest expense (net of interest capitalized)	(28.7)	(22.0)	(30.1)	(30.8)	(22.1)
Interest income	0.2	0.4	0.2	1.0	3.7
Equity in loss of affiliates, net	(14.7)	(3.4)			
Other income	3.2	1.0	0.9	1.3	0.9
Income before income taxes	334.5	389.0	322.7	193.1	134.1
Income tax expense (benefit)	(1.1)	(0.4)	1.7	0.7	(0.5)
Net income	$ 335.6	$ 389.4	$ 321.0	$ 192.4	$ 134.6
Less: Net loss attributable to noncontrolling interest				(0.2)	(0.4)
Net income attributable to Alliance Resource Partners, L.P. ("Net Income of ARLP")	$ 335.6	$ 389.4	$ 321.0	$ 192.2	$ 134.2
General Partners' interest in Net Income of ARLP	$ 106.8	$ 86.3	$ 73.2	$ 60.7	$ 45.7
Limited Partners' interest in Net Income of ARLP	$ 228.8	$ 303.1	$ 247.8	$ 131.5	$ 88.5
Basic and diluted net income of ARLP per limited partner unit(2)	$ 6.12	$ 8.13	$ 6.68	$ 3.56	$ 2.39
Distributions paid per limited partner unit	$ 4.1625	$ 3.6275	$ 3.205	$ 2.95	$ 2.53
Weighted average number of units outstanding-basic and diluted	36,863,022	36,769,126	36,710,431	36,655,555	36,604,707

Balance Sheet Data:										
Working capital	$	73.0	$	269.3	$	348.7	$	54.9	$	239.8
Total assets		1,956.0		1,731.5		1,501.3		1,051.4		1,030.6
Long-term obligations(3)		791.6		688.5		704.2		422.5		440.8
Total liabilities(4)		1,250.5		1,107.8		1,045.5		730.4		740.4
Partners' capital(4)	$	705.5	$	623.7	$	455.8	$	321.0	$	290.2
Other Operating Data:										
Tons sold		35.2		31.9		30.3		25.0		27.2
Tons produced		34.8		30.8		28.9		25.8		26.4
Coal sales per ton sold(5)	$	56.28	$	55.95	$	51.21	$	46.60	$	40.23
Cost per ton sold(6)	$	38.15	$	37.15	$	33.90	$	32.23	$	30.39
Other Financial Data:										
Net cash provided by operating activities	$	555.9	$	574.0	$	520.6	$	282.7	$	261.0
Net cash used in investing activities		(623.4)		(401.1)		(295.0)		(320.1)		(184.1)
Net cash provided by (used in) financing activities		(177.7)		(238.9)		92.7		(186.6)		166.8
EBITDA(7)		581.1		570.8		499.5		340.4		257.8
Maintenance capital expenditures(8)		282.6		192.7		90.5		96.1		77.7

(1)
Represents a realized gain in 2008 of $2.8 million on settlement of our claim against the third party that provided security services at the time of the MC Mining Fire Incident.

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(2)

Basic and diluted earnings per unit ("EPU") have been restated for the year ending December 31, 2008 due to the adoption of Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 260-10-55-102 through 55-110, *Master Limited Partnerships.* Diluted 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, 2012 and 2011, long-term incentive plan ("LTIP"), Supplemental Executive Retirement Plan ("SERP") and Directors' compensation units of 344,956 and 409,969, respectively, were considered anti-dilutive. For the years ended December 31, 2010, 2009 and 2008, LTIP units of 232,042, 176,743 and 165,175, respectively, were considered anti-dilutive.

(3)

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

(4)

On January 1, 2009, we adopted FASB ASC 810-10-65 and 810-10-45-16, which amended accounting and reporting standards for noncontrolling ownership interests in subsidiaries. As a result, noncontrolling ownership interest in consolidated subsidiaries is now presented in the consolidated balance sheet within partners' capital as a separate component from the parent's equity. Consolidated Net income now includes earnings attributable to both the parent and the noncontrolling interests.

(5)

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

(6)

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

(7)

EBITDA is a financial measure not calculated in accordance with generally accepted accounting principles ("GAAP") and is defined as net income 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):

	Year Ended December 31,				
	2012	**2011**	**2010**	**2009**	**2008**
Cash flows provided by operating activities	$ 555,856	$ 573,983	$ 520,588	$ 282,741	$ 261,041
Non-cash compensation expense	(7,428)	(6,235)	(4,051)	(3,582)	(3,931)
Asset retirement obligations	(2,853)	(2,546)	(2,579)	(2,678)	(2,827)
Coal inventory adjustment to market	(2,978)	(386)	(498)	(3,030)	(452)
Equity in loss of affiliates, net	(14,650)	(3,404)			
Net gain (loss) on foreign currency exchange			(274)	653	

Net gain (loss) on sale of property, plant and equipment	(147)	634	(234)	(136)	911
Gain on sale of coal reserves					5,159
Loss on retirement of vertical hoist conveyor system			(1,204)		
Asset impairment charge	(19,031)				
Other	3,815	(1,488)	(1,448)	(537)	(366)
Net effect of working capital changes	41,109	(10,870)	(42,402)	36,440	(19,661)
Interest expense, net	28,455	21,579	29,862	29,798	18,418
Income tax expense (benefit)	(1,082)	(431)	1,741	708	(480)
EBITDA	581,066	570,836	499,501	340,377	257,812
Depreciation, depletion and amortization	(218,122)	(160,335)	(146,881)	(117,524)	(105,278)
Interest expense, net	(28,455)	(21,579)	(29,862)	(29,798)	(18,418)
Income tax (expense) benefit	1,082	431	(1,741)	(708)	480
Net income	$ 335,571	$ 389,353	$ 321,017	$ 192,347	$ 134,596
Net loss attributable to noncontrolling interest				(190)	(420)
Net income of ARLP	$ 335,571	$ 389,353	$ 321,017	$ 192,157	$ 134,176

(8) 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 2012, we produced a record 34.8 million tons of coal and sold a record 35.2 million tons. The coal we produced in 2012 was approximately 3.8% low-sulfur coal, 18.8% medium-sulfur coal and 77.4% 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 between 1% and 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

We operate eleven underground mining complexes, including the new Tunnel Ridge longwall mine in West Virginia and the Onton mine in west Kentucky acquired on April 2, 2012, and operate a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. We are constructing an additional mine at our southern Indiana Gibson County Coal mining complex and purchasing and funding development of reserves, constructing surface facilities and making equity investments in White Oak's new mining complex in southern Illinois. Please see "Item 1. Business Mining Operations" for further discussion of our mines. At December 31, 2012, we had approximately 919.5 million tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. Approximately 204.9 million tons of those reserves are leased to White Oak. For more information on White Oak, please read "Item 8. Financial Statements and Supplementary Data Note 12. White Oak Transactions." We believe we control adequate reserves to implement our currently contemplated mining plans.

In 2012, approximately 93.1% of our sales tonnage was purchased by electric utilities, with the balance sold to third-party resellers and industrial consumers. In 2012, approximately 94.2% 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 2012, approximately 94.1% 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 greenhouse gas 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."

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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, while we do not pay our customers' transportation costs, they 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 five reportable segments: the Illinois Basin, Central Appalachia, Northern Appalachia, White Oak and Other and Corporate. The first three reportable segments correspond to the three major coal producing regions in the eastern U.S. Factors similarly affecting financial performance of our operating segments within each of these three reportable segments include coal quality, coal seam height, mining and transportation methods and regulatory issues. The White Oak reportable segment is comprised of our activities associated with the White Oak longwall Mine No. 1 development project in southern Illinois 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 project, Hopkins County Coal's Elk Creek mining complex, White County Coal's Pattiki mining complex, Warrior's mining complex, the Sebree Mining complex, which includes the Onton mine, Steamport and certain Sebree Reserves, River View's mining complex, CR Services, and certain properties of Alliance Resource Properties, ARP Sebree and ARP Sebree South. The development of the Gibson South mine is currently underway and we are in the process of permitting the Sebree Reserves and related 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*" and for information regarding the acquisition of the Onton mine which was added to the Illinois Basin segment in April 2012, please read "Item 8. Financial Statements and Supplementary Data Note 4. Acquisition of Business" of this Annual Report on Form 10-K.

- *Central Appalachian* reportable segment is comprised of two operating segments, the MC Mining and Pontiki mining complexes. The Pontiki mining complex was idled on August 29, 2012 and resumed operations on November 25, 2012. Please read "Item 8. Financial Statements and Supplementary Data Note 5. Asset Impairment Charge" of this Annual Report on Form 10-K and discussions below regarding an asset impairment charge of $19.0 million related to the idling of our Pontiki mining complex.

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Northern Appalachian reportable segment is comprised of multiple operating segments, including Mettiki (MD)'s mining complex, Mettiki (WV)'s Mountain View mining complex, two small third-party mining operations (one of which ceased operations in July 2011), the Tunnel Ridge mining complex and the Penn Ridge Coal property. 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 at White Oak currently under construction and the equity investment in White Oak. WOR Properties owns reserves acquired from White Oak and is committed to acquiring additional reserves from White Oak with a lease-back arrangement. WOR Properties has also completed initial funding commitments 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. White Oak Transactions" of this Annual Report on Form 10-K.

Other and Corporate reportable segment includes marketing and administrative expenses, Alliance Service, Inc. ("ASI") and Matrix Group and ASI's ownership of aircraft, the Mt. Vernon dock activities, coal brokerage activity, our equity investment in MAC, and certain activities of Alliance Resource Properties. For more information on ASI, please read "Item 8. Financial Statements and Supplementary Data Note 19. Related-Party Transactions" 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 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;

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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. We define Segment Adjusted EBITDA (a non-GAAP financial measure) as net income 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.

Health Care Reform

On March 23, 2010, President Obama signed into law the PPACA. Additionally, on March 30, 2010, President Obama signed into law a reconciliation measure, the Health Care and Education Reconciliation Act of 2010. Implementation of the PPACA and the Health Care and Education Reconciliation Act (collectively, the "Health Care Act") will result in comprehensive changes to health care in the U.S. Implementation of this legislation is planned to occur in phases, with standard plan changes already taking effect and extending through 2018.

The Health Care Act continues to have implications on benefit plan eligibility, coverage requirements, and benefit standards and limitations. In the long-term, our plan's health care costs are expected to increase for various reasons due to the Health Care Act, including the potential impact of an excise tax on "high cost" plans (beginning in 2018), among other standard requirements. We have chosen not to "grandfather" our health care plan as allowed under the Health Care Act. This decision allows us to make benefit modifications that encourage participants to use high-value, lower-cost medical-care options such as on-site medical services, generic preferred medications, and urgent-care centers instead of emergency rooms.

In June 2012, the U.S. Supreme Court upheld the Health Care Act. As a result, we anticipate that certain government agencies will provide additional regulations or interpretations concerning the application of the Health Care Act and reporting required thereunder. However, until these regulations and interpretations are published, we are unable to reasonably estimate the further impact of the federal mandate requirements on our future health care costs.

The Health Care Act also amended previous legislation related to coal workers' pneumoconiosis, or black lung, providing automatic extension of awarded lifetime benefits to surviving spouses and providing changes to the legal criteria used to assess and award claims. The impact of these changes to our current population of beneficiaries and claimants resulted in an estimated $8.3 million increase to our black lung obligation at December 31, 2010. This increase to our obligation excludes the impact of potential re-filing of closed claims and potential filing rates for employees who terminated more than seven years ago as we do not have sufficient information to determine what, if any, claims will be filed until regulations are issued or claim development patterns are identified through future litigation of claims. The issuance of these regulations, if any, is currently uncertain and may take place over the next several years.

We will continue to evaluate the potential impact of the legislation on our self-insured long-term disability plan, black lung liabilities, results of operations and internal controls as governmental agencies issue interpretations regarding the meaning and scope of the Health Care Act. However, we believe it is likely that our costs will continue to increase as a result of these provisions, which may have an adverse impact on our results of operations and cash flows.

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Analysis of Historical Results of Operations

2012 Compared with 2011

We reported net income of $335.6 million in 2012 compared to $389.4 million in 2011. This decrease of $53.8 million was principally due to higher operating expenses and depreciation, depletion and amortization, reduced coal sales volumes from our Mettiki mine into the metallurgical export markets, an asset impairment charge related to our Pontiki mining complex, and the increase in the pass through of losses, as anticipated, related to our investments in the White Oak Mine No. 1 development project. These decreases to net income were offset partially by record revenues driven by record tons sold, resulting primarily from the start-up of longwall production from our Tunnel Ridge mine, increased production from our River View mine, and production from the recently acquired Onton mine, as well as improved pricing from our Illinois Basin coal contracts. Higher operating expenses resulted from increased sales and production volumes, which particularly impacted materials and supplies expenses, labor-related expenses, maintenance costs and sales-related expenses. Also, higher operating expenses per ton reflect significantly lower coal recoveries from our Dotiki run-of-mine production as the mine completed its transition into a new coal seam during 2012 and the impact of regulatory actions on production and margins at our Central Appalachian mines and particularly our Pontiki mine. Anticipated increases in depreciation, depletion and amortization were attributable to the start-up of longwall production at the Tunnel Ridge mine, the addition of the Onton mine and capital expenditures related to infrastructure improvements at various other operations.

Increased revenues reflect record sales and production volumes, which increased to 35.2 million tons sold and 34.8 million tons produced in 2012 compared to 31.9 million tons sold and 30.8 million tons produced in 2011. A higher average coal sales price in 2012, which increased to $56.28 per ton sold as compared to $55.95 per ton sold in 2011, resulted from improved contract pricing for Illinois Basin coal sales offset partially by lower coal volumes sold by our Mettiki mine into the metallurgical export markets. The increase in produced tons primarily reflects increased production at our Tunnel Ridge mine, which initiated longwall production in May 2012, expansion of production at our River View and Warrior mines and the acquisition of the Onton mine in April 2012.

	December 31,		December 31,	
	2012	2011	2012	2011
	(in thousands)		(per ton sold)	
Tons sold	35,170	31,925	N/A	N/A
Tons produced	34,800	30,753	N/A	N/A
Coal sales	$ 1,979,437	$ 1,786,089	$ 56.28	$ 55.95
Operating expenses and outside coal purchases	$ 1,341,898	$ 1,186,030	$ 38.15	$ 37.15

Coal sales. Coal sales increased 10.8% to $2.0 billion in 2012 from $1.8 billion in 2011. The increase of $193.3 million reflected the benefit of record tons sold (contributing $181.7 million in additional coal sales) and record average coal sales prices (contributing $11.6 million in coal sales). Average coal sales price increased $0.33 per ton sold in 2012 to $56.28 per ton compared to $55.95 per ton in 2011, primarily as a result of improved contract pricing in the Illinois Basin region offset partially by reduced Mettiki coal sales into the metallurgical export markets.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases increased 13.1% to $1.3 billion in 2012 from $1.2 billion in 2011 primarily due to record coal sales and production volumes. On a per ton basis, operating expenses and outside coal purchases increased 2.7% to

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$38.15 per ton sold from $37.15 in 2011. In addition to the impact of record volumes, increased operating expenses reflect various other factors, the most significant of which are discussed below:

Labor and benefit expenses per ton produced, excluding workers' compensation, increased 3.4% to $12.48 per ton in 2012 from $12.07 per ton in 2011. The increase of $0.41 per ton reflects wage increases and higher benefit expenses, particularly increased health care and retirement expenses, the impact of increased headcount at Tunnel Ridge as we continued to hire and train additional employees prior to the start-up of longwall operations and, as discussed above, the production impacts resulting from Dotiki's lower coal recoveries and regulatory actions at our Central Appalachian mines, offset partially by higher production at our Tunnel Ridge mine, subsequent to the start-up of longwall production, and our River View and Warrior mines;

Material and supplies expenses per ton produced increased to $12.36 per ton in 2012 from $12.26 per ton in 2011. The increase of $0.10 per ton resulted from higher costs for certain products and services, primarily contract labor used in the mining process (increase of $0.43 per ton), partially offset by lower roof support expenses per ton (decrease of $0.20 per ton) and certain safety-related materials and supplies expenses per ton (decrease of $0.10 per ton);

Production taxes and royalties (which were incurred as a percentage of coal sales or based on coal volumes) increased $0.24 per produced ton sold in 2012 compared to 2011, primarily resulting from an increased mix of sales and production from certain mines as discussed above, in states with higher severance tax rates; and

Capitalization of mine development expenses related to the construction of the Tunnel Ridge mine declined $23.6 million in 2012 compared to 2011. Capitalized development ceased in May 2012 with the startup of longwall production. 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.

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

Workers' compensation expenses per ton produced decreased to $0.70 per ton in 2012 from $0.79 per ton in 2011. The decrease of $0.09 per ton resulted primarily from favorable reserve adjustments for claims incurred in prior years;

Contract mining expenses decreased $3.1 million in 2012 compared to 2011. The decrease primarily reflects the permanent closure in July 2011 of one third-party mining operation at our Mettiki mining complex in the Northern Appalachian region; and

Outside coal purchases decreased to $38.6 million in 2012 from $54.3 million in 2011. The decrease of $15.7 million was primarily attributable to decreased purchases of brokerage coal and coal for sale into the metallurgical export markets. Coal purchase costs per ton are typically higher than our production costs per ton, thus significantly lower volumes of coal purchases in 2012 compared to 2011 reduced our overall total expense per ton.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, Matrix Design sales and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to $32.8 million in 2012 from $25.5 million in 2011. The increase of $7.3 million was primarily attributable to amounts received from a customer for the partial buy-out of a certain Northern Appalachian coal contract.

General and administrative. General and administrative expenses for 2012 increased to $58.7 million compared to $52.3 million in 2011. The increase of $6.4 million was primarily due to increases in other professional services and higher salary and incentive compensation expenses resulting, in part, from increased headcount.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $218.1 million in 2012 compared to $160.3 million in 2011. The increase of $57.8 million was primarily attributable to the start-up of longwall production at the Tunnel Ridge mine, the addition of the Onton mine and capital expenditures related to 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. Due to regulatory actions requiring certain surface facility repairs, the Pontiki mining complex was idled from August 29, 2012 to November 25, 2012. The asset impairment charge is primarily the result of the mine being idled, increased regulatory costs and uncertainty regarding the mine's future operations and market opportunities as discussed in more detail below and in "Item 8. Financial Statements and Supplementary Data Note 5. Asset Impairment Charge."

Interest expense. Interest expense, net of capitalized interest, increased to $28.7 million in 2012 from $22.0 million in 2011. The increase of $6.7 million was principally attributable to lower capitalized interest in 2012 compared to 2011 due to a nonrecurring adjustment to capitalized interest in 2011, and increased borrowings under our revolving credit facility during 2012, as well as a $1.1 million write-off of deferred debt issuance costs in 2012 related to the early termination of a term loan. These increases were partially offset by reduced interest expense resulting from our August 2012 principal repayment of $18.0 million on our original senior notes issued in 1999 and lower rates and fees under our new term loan and revolving credit facility. The term loan and revolving credit facility entered into during 2012 are discussed in more detail below under "Debt Obligations." For more information on the nonrecurring adjustment to capitalized interest, please read "Item 8. Financial Statements and Supplementary Data Note 23. Selected Quarterly Financial Data (Unaudited)."

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. As anticipated, equity in loss of affiliates was $14.7 million in 2012 compared to $3.4 million in 2011, which was primarily attributable to losses allocated to us due to our equity investment in White Oak which began in September 2011. For more information regarding White Oak, please read "Item 8. Financial Statements and Supplementary Data Note 12. White Oak Transactions" of this Annual Report on Form 10-K.

Transportation revenues and expenses. Transportation revenues and expenses each decreased to $22.0 million in 2012 from $31.9 million in 2011. The decrease of $9.9 million was primarily attributable to reduced tonnage in 2012 for which we arranged the transportation compared to 2011, as well as a decrease in average transportation rates in 2012. 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 benefit. Income tax benefit was $1.1 million in 2012 compared to $0.4 million in 2011. Income taxes are primarily due to the operations of Matrix Design. The income tax benefit for 2012 was due to a net operating loss carryforward 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 2012 Segment Adjusted EBITDA increased 5.7% to $658.8 million from 2011 Segment Adjusted EBITDA of $623.2 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,			
	2012	2011	Increase (Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 593,054	$ 505,113	$ 87,941	17.4%
Central Appalachia	25,712	53,729	(28,017)	(52.1)%
Northern Appalachia	47,933	62,395	(14,462)	(23.2)%
White Oak	(13,987)	(4,407)	(9,580)	(1)
Other and Corporate	6,122	6,340	(218)	(3.4)%
Elimination				
Total Segment Adjusted EBITDA(2)	$ 658,834	$ 623,170	$ 35,664	5.7%
Tons sold				
Illinois Basin	28,294	25,561	2,733	10.7%
Central Appalachia	1,951	2,548	(597)	(23.4)%
Northern Appalachia	4,670	3,277	1,393	42.5%
White Oak				
Other and Corporate	255	539	(284)	(52.7)%
Elimination				
Total tons sold	35,170	31,925	3,245	10.2%
Coal sales				
Illinois Basin	$ 1,485,640	$ 1,289,590	$ 196,050	15.2%
Central Appalachia	156,836	204,673	(47,837)	(23.4)%
Northern Appalachia	315,801	262,286	53,515	20.4%
White Oak				
Other and Corporate	21,160	29,540	(8,380)	(28.4)%
Elimination				
Total coal sales	$ 1,979,437	$ 1,786,089	$ 193,348	10.8%
Other sales and operating revenues				
Illinois Basin	$ 2,183	$ 1,638	$ 545	33.3%
Central Appalachia	23	157	(134)	(85.4)%
Northern Appalachia	9,869	3,427	6,442	(1)
White Oak				
Other and Corporate	37,283	35,478	1,805	5.1%
Elimination	(16,528)	(15,168)	(1,360)	9.0%
Total other sales and operating revenues	$ 32,830	$ 25,532	$ 7,298	28.6%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 894,769	$ 786,116	$ 108,653	13.8%
Central Appalachia	131,148	151,101	(19,953)	(13.2)%
Northern Appalachia	277,736	203,317	74,419	36.6%
White Oak	(1,347)	155	(1,502)	(1)
Other and Corporate	53,005	59,526	(6,521)	(11.0)%
Elimination	(16,528)	(15,168)	(1,360)	9.0%
Total Segment Adjusted EBITDA Expense(3)	$ 1,338,783	$ 1,185,047	$ 153,736	13.0%

(1) Percentage increase or decrease 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 before net interest expense, income taxes, depreciation, depletion and amortization, interest, 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 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,	
	2012	**2011**
Segment Adjusted EBITDA	$ 658,834	$ 623,170
General and administrative	(58,737)	(52,334)
Depreciation, depletion and amortization	(218,122)	(160,335)
Asset impairment charge	(19,031)	
Interest expense, net	(28,455)	(21,579)
Income tax benefit	1,082	431
Net income	$ 335,571	$ 389,353

(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 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,	
	2012	2011
Segment Adjusted EBITDA Expense	$ 1,338,783	$ 1,185,047
Outside coal purchases	(38,607)	(54,280)
Other income	3,115	983
Operating expense (excluding depreciation, depletion and amortization)	$ 1,303,291	$ 1,131,750

Illinois Basin Segment Adjusted EBITDA increased 17.4% to $593.1 million in 2012 from $505.1 million in 2011. The increase of $88.0 million was primarily attributable to increased tons sold, which rose 10.7% to 28.3 million tons sold in 2012, as well as improved contract pricing resulting in a higher average coal sales price of $52.51 per ton in 2012 compared to $50.45 per ton in 2011. Coal sales increased 15.2% to $1.5 billion in 2012 compared to $1.3 billion in 2011. The increase of $0.2 billion reflects the higher average coal sales price discussed above as well as increased tons produced and sold from expansion of production at our River View and Warrior mines and the addition of the Onton mine, offset partially by the impact of difficult mining conditions at our Dotiki and Hopkins mines. Total Segment Adjusted EBITDA Expense in 2012 increased 13.8% to $894.8 million from $786.1 million in 2011 and increased $0.87 per ton sold to $31.62 from $30.75 per ton sold, primarily as a result of certain cost variances described above in the discussion of consolidated operating expenses, lower coal recoveries at our Dotiki mine as it completed transition into a new coal seam and the Hopkins mine due to adverse geological conditions, and higher cost per ton production from the Onton mine acquired on April 2, 2012. The Dotiki mine completed the transfer of all mining units to the new seam in mid-September 2012.

Central Appalachia For 2012, Central Appalachia tons sold decreased 23.4% to 2.0 million tons sold. The decrease in tons sold was primarily due to regulatory actions which idled the Pontiki mining complex from August 29, 2012 to November 25, 2012, in addition to an MSHA required mining unit reduction at both Central Appalachian mines in recent quarters. This decrease in tons sold resulted in lower Segment Adjusted EBITDA, which decreased 52.1% to $25.7 million in 2012 compared to $53.7 million in 2011, and total Segment Adjusted EBITDA Expense for 2012, which decreased 13.2% to $131.1 million from $151.1 million in 2011. Although Segment Adjusted EBITDA Expense decreased in 2012, Segment Adjusted EBITDA Expense per ton increased 13.3% to $67.22 per ton in 2012 from $59.31 per ton in 2011 primarily as a result of production issues discussed above and related lower coal sales volumes, as well as other cost increases described above in the discussion of consolidated operating expenses. For additional detail related to the Pontiki mining complex read below and "Item 8. Financial Statements and Supplementary Data Note 5. Asset Impairment Charge."

Northern Appalachia Segment Adjusted EBITDA decreased 23.2% to $47.9 million in 2012, compared to $62.4 million in 2011. The decrease of $14.5 million was primarily attributable to decreased coal volumes sold into the metallurgical export markets resulting in a lower average sales price of $67.62 per ton sold in 2012 compared to $80.05 per ton sold in 2011. This decrease in coal sales price per ton was partially offset by increased tons sold, which increased 42.5% to 4.7 million tons in 2012 due to the start-up of longwall production at the Tunnel Ridge mine, which began in May 2012. The start-up of longwall production at Tunnel Ridge was also the primary reason for a 36.6% increase in Segment Adjusted EBITDA Expense in 2012 to $277.7 million compared to $203.3 million in 2011. Although Segment Adjusted EBITDA Expense increased in 2012, Segment Adjusted EBITDA Expense per ton decreased by $2.58 per ton sold to $59.47 from $62.05 in 2011, primarily due to the lower cost per ton from longwall production at Tunnel Ridge and lower costs at our Mettiki complex due to reduced coal processing expenses and coal purchases.

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White Oak Segment Adjusted EBITDA was $(14.0) million in 2012 primarily due to losses allocated to us due to our equity investment in White Oak compared to $(4.4) million in 2011. Our investment in White Oak began in September 2011.

Other and Corporate Coal sales decreased $8.4 million to $21.2 million in 2012 due to lower coal brokerage sales. Segment Adjusted EBITDA Expense decreased 11.0% to $53.0 million for 2012, primarily due to lower outside coal purchases, offset in part by increased component expenses related to Matrix Group safety equipment sales.

2011 Compared with 2010

We reported record net income of $389.4 million in 2011 compared to $321.0 million in 2010. This increase of $68.4 million was principally due to increased tons sold and improved contract pricing resulting in an average coal sales price of $55.95 per ton sold, as compared to $51.21 per ton sold in 2010. We sold 31.9 million tons and produced 30.8 million tons in 2011 compared to 30.3 million tons sold and 28.9 million tons produced in 2010. This increase in tons sold and produced primarily reflects increased production from our River View mine and the resumption of full production at our Pattiki mine in early 2011, as well as expanded coal brokerage activity. Higher operating expenses during 2011 resulted primarily from increased sales and production volumes, which particularly impacted materials and supplies expenses, sales-related expenses, maintenance costs and labor costs. Increased operating expenses also reflect increased incidental production at our Tunnel Ridge mine and higher outside coal purchases.

	December 31,		December 31,	
	2011	**2010**	**2011**	**2010**
	(in thousands)		**(per ton sold)**	
Tons sold	31,925	30,295	N/A	N/A
Tons produced	30,753	28,860	N/A	N/A
Coal sales	$ 1,786,089	$ 1,551,539	$ 55.95	$ 51.21
Operating expenses and outside coal purchases	$ 1,186,030	$ 1,027,013	$ 37.15	$ 33.90

Coal sales. Coal sales increased 15.1% to $1.8 billion in 2011 from $1.6 billion in 2010. The increase of $234.6 million reflected the benefit of higher average coal sales prices (contributing $151.2 million in coal sales) and increased tons sold (contributing $83.4 million in additional coal sales). Average coal sales price increased $4.74 per ton sold in 2011 to $55.95 per ton compared to $51.21 per ton in 2010, primarily as a result of improved contract pricing across all regions.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases increased 15.5% to $1.2 billion in 2011 from $1.0 billion in 2010 primarily due to record coal sales and production volumes. On a per ton basis, operating expenses and outside coal purchases increased 9.6% to $37.15 per ton sold. 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, increased 10.0% to $12.07 per ton in 2011 from $10.97 per ton in 2010. The increase of $1.10 per ton represents increased labor costs at our Illinois Basin mines and our Mettiki mine, as well as higher mine development labor and benefits at our Tunnel Ridge mine, partially offset by increased production at our River View, Pattiki and MC Mining mines;

Workers' compensation expenses per ton produced increased to $0.79 per ton in 2011 from $0.72 per ton in 2010. The increase of $0.07 per ton primarily reflected a non-cash charge that resulted from a decrease in the discount rate to 3.75% at the end of 2011 from 4.70% at the end of 2010;

Material and supplies expenses per ton produced increased 16.2% to $12.26 per ton in 2011 from $10.55 per ton in 2010. The increase of $1.71 per ton resulted from increased costs for certain products and services, primarily roof support (increase of $0.57 per ton), outside services and contract labor used in the mining process (increase of $0.44 per ton), power and fuel used in the mining process (increase of $0.27 per ton), certain safety related materials and supplies (increase of $0.17 per ton) and ventilation (increase of $0.14 per ton), in addition to the cost impact resulting from heightened regulatory oversight;

Maintenance expenses per ton produced increased 15.4% to $4.19 per ton in 2011 from $3.63 per ton in 2010. The increase of $0.56 per produced ton was primarily due to higher maintenance costs on continuous miners and shuttle cars in the Illinois Basin and Northern Appalachian regions, increased longwall maintenance costs at our Mettiki mine and higher costs in other various categories;

Mine administration expenses increased $6.3 million in 2011 compared to 2010, primarily due to higher regulatory costs, insurance costs and increased components expense associated with safety equipment sales by Matrix Group;

Contract mining expenses decreased $1.3 million in 2011 compared to 2010. The decrease primarily reflects the permanent closure of one third-party mining operation in the Northern Appalachian region during July 2011;

Production taxes and royalties (which were incurred as a percentage of coal sales or based on coal volumes) increased $0.34 per produced ton sold in 2011 compared to 2010, primarily as a result of increased average coal sales prices across all regions;

Operating expenses per ton sold for 2011 benefited, compared to 2010, from lower sales of beginning-of-the- year coal inventory, which typically bears a seasonally higher cost per ton. Beginning-of-the-year coal inventories were 0.3 million tons and 1.3 million tons for 2011 and 2010, respectively;

Operating expenses in 2010 included $1.2 million for the retirement of certain assets resulting from the failure of the vertical hoist conveyor system at our Pattiki mine. For more information, please read "Part II. Item 8. Financial Statements and Supplementary Data Note 3. Pattiki Vertical Hoist Conveyor System Failure in 2010" of this Annual Report on Form 10-K; and

Outside coal purchases increased to $54.3 million in 2011 from $17.1 million in 2010. The increase of $37.2 million was primarily attributable to increased coal brokerage activity as well as Mettiki's higher tons and cost per ton of coal purchased, both in 2011.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, Matrix Design sales and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to $25.5 million in 2011 from $24.9 million in 2010. The increase of $0.6 million was primarily attributable to increased Matrix Design sales, partially offset by lower transloading revenues.

General and administrative. General and administrative expenses in 2011 increased to $52.3 million compared to $50.8 million in 2010. The increase of $1.5 million was primarily attributable to higher salary and benefit costs related to increased staffing levels.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $160.3 million in 2011 compared to $146.9 million in 2010. The increase of $13.4 million was primarily attributable to additional depreciation expense associated with our River View mine, infrastructure and equipment expenditures at our Dotiki mine and capital expenditures related to various infrastructure improvements and efficiency projects at other mining operations.

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Interest expense. Interest expense, net of capitalized interest, decreased to $22.0 million in 2011 from $30.1 million in 2010. The decrease of $8.1 million was principally attributable to a nonrecurring adjustment to capitalized interest and reduced interest expense resulting from annual principal repayments made during August 2011 and 2010 of $18.0 million on our original senior notes issued in 1999, partially offset by increased interest expense resulting from our $300 million term loan, which was completed in the fourth quarter of 2010 and is discussed in more detail below under " Debt Obligations." For more information on the nonrecurring adjustment to capitalized interest, please read "Item 8. Financial Statements and Supplementary Data Note 23. Selected Quarterly Financial Data (Unaudited)" of this Annual Report on Form 10-K.

Equity in loss of affiliates, net. Equity in loss of affiliates, net includes our new equity investments in White Oak and MAC. For 2011, equity in loss of affiliates was $3.4 million, which was primarily attributable to losses allocated to us due to our equity investment in White Oak.

Transportation revenues and expenses. Transportation revenues and expenses each decreased to $31.9 million in 2011 from $33.6 million in 2010. The decrease of $1.7 million was primarily attributable to reduced tonnage in 2011 for which we arranged the transportation compared to 2010 partially offset by an increase in average transportation rates. 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). The income tax benefit was $0.4 million in 2011 compared to income tax expense of $1.7 million in 2010. Income taxes are primarily due to the operations of Matrix Design, which is owned by our subsidiary, ASI. The income tax benefit was due to operating losses in 2011 from our Matrix Design operation.

Segment Information. Our 2011 Segment Adjusted EBITDA increased 13.2% to $623.2 million from 2010 Segment Adjusted EBITDA of $550.3 million. Segment Adjusted EBITDA, tons sold, coal sales,

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other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows (in thousands):

	Year Ended December 31,			
	2011	2010	Increase (Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 505,113	$ 460,592	$ 44,521	9.7%
Central Appalachia	53,729	36,714	17,015	46.3%
Northern Appalachia	62,395	46,702	15,693	33.6%
White Oak	(4,407)		(4,407)	(1)
Other and Corporate	6,340	6,311	29	0.5%
Elimination				
Total Segment Adjusted EBITDA(2)	$ 623,170	$ 550,319	$ 72,851	13.2%
Tons sold				
Illinois Basin	25,561	24,763	798	3.2%
Central Appalachia	2,548	2,221	327	14.7%
Northern Appalachia	3,277	3,256	21	0.6%
White Oak				
Other and Corporate	539	55	484	(1)
Elimination				
Total tons sold	31,925	30,295	1,630	5.4%
Coal sales				
Illinois Basin	$ 1,289,590	$ 1,176,275	$ 113,315	9.6%
Central Appalachia	204,673	164,834	39,839	24.2%
Northern Appalachia	262,286	207,057	55,229	26.7%
White Oak				
Other and Corporate	29,540	3,373	26,167	(1)
Elimination				
Total coal sales	$ 1,786,089	$ 1,551,539	$ 234,550	15.1%
Other sales and operating revenues				
Illinois Basin	$ 1,638	$ 1,357	$ 281	20.7%
Central Appalachia	157	199	(42)	(21.1)%
Northern Appalachia	3,427	3,520	(93)	(2.6)%
White Oak				
Other and Corporate	35,478	41,681	(6,203)	(14.9)%
Elimination	(15,168)	(21,815)	6,647	30.5%
Total other sales and operating revenues	$ 25,532	$ 24,942	$ 590	2.4%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 786,116	$ 717,040	$ 69,076	9.6%
Central Appalachia	151,101	128,318	22,783	17.8%
Northern Appalachia	203,317	163,876	39,441	24.1%
White Oak	155		155	(1)
Other and Corporate	59,526	38,743	20,783	53.6%
Elimination	(15,168)	(21,815)	6,647	30.5%
Total Segment Adjusted EBITDA Expense(3)	$ 1,185,047	$ 1,026,162	$ 158,885	15.5%

(1)

Percentage increase or decrease was greater than or equal to 100%.

(2) Segment Adjusted EBITDA (a non-GAAP financial measure) is defined as net income 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

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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 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,	
	2011	**2010**
Segment Adjusted EBITDA	$ 623,170	$ 550,319
General and administrative	(52,334)	(50,818)
Depreciation, depletion and amortization	(160,335)	(146,881)
Interest expense, net	(21,579)	(29,862)
Income tax (expense) benefit	431	(1,741)
Net income	$ 389,353	$ 321,017

(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 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,	
	2011	2010
Segment Adjusted EBITDA Expense	$ 1,185,047	$ 1,026,162
Outside coal purchases	(54,280)	(17,078)
Other income	983	851
Operating expense (excluding depreciation, depletion and amortization)	$ 1,131,750	$ 1,009,935

Illinois Basin Segment Adjusted EBITDA increased 9.7% to $505.1 million in 2011 from $460.6 million in 2010. The increase of $44.5 million was primarily attributable to improved contract pricing resulting in a higher average coal sales price of $50.45 per ton during 2011 compared to $47.50 per ton in 2010, as well as increased tons sold, which increased 3.2% to 25.6 million tons sold in 2011. Coal sales increased 9.6% to $1.3 billion in 2011 compared to $1.2 billion in 2010. The increase of $0.1 billion reflects the increase in average coal sales price discussed above and increased tons produced and sold from expansion of production capacity at our River View mine and resumption of full production at our Pattiki mine in the first quarter of 2011, offset partially by difficult mining conditions at our Dotiki and Warrior mines. Total Segment Adjusted EBITDA Expense in 2011 increased 9.6% to $786.1 million from $717.0 million in 2010, an increase of $1.79 per ton sold to $30.75 from $28.96 per ton sold, primarily as a result of certain cost increases described above under consolidated operating expenses, as well as lower production at the Dotiki and Warrior mines due to difficult mining conditions and weather related disruptions at the Gibson North mine. The per ton increases were partially offset by higher production at our River View and Pattiki mines in 2011 and the impact on 2010 of a $1.2 million loss on the retirement of certain assets related to the failed vertical hoist conveyor system at our Pattiki mine. For more information on Pattiki, please read "Item 8. Financial Statements and Supplementary Data Note 3. Pattiki Vertical Hoist Conveyor System Failure in 2010" of this Annual Report on Form 10-K.

Central Appalachia Segment Adjusted EBITDA increased 46.3% to $53.7 million in 2011, compared to $36.7 million in 2010. The increase of $17.0 million was primarily attributable to increased tons sold, which increased 14.7% to 2.5 million tons sold in 2011, as well as improved contract pricing resulting in a higher average coal sales price of $80.34 per ton sold during 2011 compared to $74.19 per ton sold in 2010. Total Segment Adjusted EBITDA Expense during 2011 increased 17.8% to $151.1 million from $128.3 million during 2010, an increase of $1.55 per ton sold to $59.31 from $57.76 per ton sold, primarily as a result of certain cost increases described above under consolidated operating expenses, particularly the impact of increasingly stringent regulatory compliance which caused the idling of our Pontiki mine for approximately 24 consecutive days in the fourth quarter of 2011.

Northern Appalachia Segment Adjusted EBITDA increased to $62.4 million in 2011, compared to $46.7 million in 2010. The increase of $15.7 million was primarily attributable to improved contract pricing in the export coal markets resulting in a higher average sales price of $80.05 per ton sold in 2011 compared to $63.60 per ton sold in 2010. Segment Adjusted EBITDA Expense for 2011 increased 24.1% to $203.3 million from $163.9 million in 2010, an increase of $11.71 per ton sold to $62.05 from $50.34 per ton sold, primarily as a result of increased cost per ton of coal purchased for sale, additional longwall move days at our Mettiki mine in 2011 compared to 2010 and lower coal recoveries due to adverse geologic conditions, as well as the other cost increases described above under consolidated operating expenses, including expenses related to our Tunnel Ridge mine.

White Oak Segment Adjusted EBITDA was $(4.4) million in 2011 primarily due to losses allocated to us due to our new equity interest in White Oak.

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Other and Corporate Tons sold increased to 0.5 million tons during 2011 due to increased coal brokerage activity compared to 2010. Other sales and operating revenues decreased 14.9% to $35.5 million for 2011 compared to $41.7 million for 2010. The decrease of $6.2 million was primarily attributable to lower Matrix Group safety equipment sales. Segment Adjusted EBITDA Expense increased 53.6% to $59.5 million for 2011, primarily due to increased coal brokerage activities and increased component expenses and research costs associated with services revenue and safety equipment sales by Matrix Group.

Pattiki Vertical Hoist Conveyor System Failure in 2010

On May 13, 2010, White County Coal's Pattiki mine was temporarily idled following the failure of the vertical hoist conveyor system used in conveying raw coal out of the mine. Our operating expenses for the year ended December 31, 2010 include $1.2 million for retirement of certain assets related to the failed vertical hoist conveyor system in addition to other repair and clean-up expenses that were not significant on a consolidated or segment basis. As the loss on the vertical hoist conveyor system did not exceed the deductible under our commercial property (including business interruption) insurance policies, we did not recover any amounts under such policies.

While the Pattiki mine was temporarily idled, we expanded coal production at our other coal mines in the region, including the addition of the seventh and eighth production units at the River View mine, to partially offset the loss of production from the Pattiki mine. Consequently, the temporary idling of the Pattiki mine in 2010 did not have a material adverse impact on our results of operations and cash flows. On July 19, 2010, the Pattiki mine resumed limited production while White County Coal continued to assess the effectiveness and reliability of the repaired vertical hoist conveyor system. On January 3, 2011, the Pattiki mine returned to full production capacity.

Pontiki Mine Asset Impairment Charge

Pontiki's mining complex in Martin County, Kentucky was idled from August 29, 2012 to November 25, 2012. MSHA ordered the closure of the coal preparation plant and associated surface facilities at the Pontiki mining complex following the failure on August 23, 2012 of a belt line between two clean coal stacking tubes. MSHA required a comprehensive structural inspection of all the surface facilities by an independent bridge engineering firm before the surface facilities could be reopened. Although the Pontiki mining complex resumed operations to fulfill contractual obligations for the delivery of coal in 2013 under existing coal sales agreements, significant uncertainty remains regarding market demand and pricing for coal from Pontiki beyond 2013. This uncertainty along with the likelihood of future cost increases arising from stringent regulatory oversight places the long-term viability of Pontiki at significant risk.

As a result of the above events, which included uncertainty around the future operations of the mine and the required additional repair costs, and our assessment of related risks, we concluded that indicators of impairment were present and the carrying value of the asset group representing the Pontiki mining complex ("Pontiki Assets") was not fully recoverable. We estimated the fair value of the Pontiki Assets and determined it was exceeded by the carrying value and accordingly, we recorded an asset impairment charge of $19.0 million in our Central Appalachian segment during the quarter ended September 30, 2012 to reduce the carrying value of the Pontiki Assets to their estimated fair value of $16.1 million. The fair value of the Pontiki Assets was determined using the market and cost valuation techniques. The fair value analysis was based on the marketability of coal properties in the current market environment, discounted projected future cash flows, and estimated fair value of assets that could be sold or used at other operations. These estimates incorporate certain assumptions, including replacement cost of equipment and marketability of coal reserves in the Central Appalachian region, and it is possible that the estimates may change in the future resulting in the need to adjust our determination of fair value. The asset impairment established a new cost basis on which depreciation, depletion and amortization is calculated for the Pontiki Assets.

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.

Liquidity and Capital Resources

Liquidity

We have historically satisfied our working capital requirements and funded our capital expenditures 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 additional 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 currently under construction. At December 31, 2012, we had funded $191.0 million related to these transactions and we expect to fund a total of approximately $300.5 million to $425.5 million from the Transaction Date through the next two to three years, which includes the funding made to White Oak through December 31, 2012 discussed above. We plan to utilize existing cash balances, future cash flows from operations, borrowings under credit 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. White Oak Transactions" of this Annual Report on Form 10-K.

Cash Flows

Cash provided by operating activities was $555.9 million in 2012 compared to $574.0 million in 2011. The decrease in cash provided by operating activities was primarily due to lower net income and increased coal inventory levels, certain prepaid expenses and accounts receivable in 2012 compared to 2011.

Net cash used in investing activities was $623.4 million in 2012 compared to $401.1 million in 2011. The increase in cash used for investing activities was primarily attributable to the purchase of the Onton mine, higher capital expenditures for mine infrastructure and equipment at various mines, particularly the Warrior, River View, and MC Mining mines, and our funding of the White Oak project during 2012. For information regarding the acquisition of the Onton mine and White Oak, please read "Item 8. Financial Statements and Supplementary Data Note 4. Acquisition of Business" and "Item 8. Financial Statements and Supplementary Data Note 12. White Oak Transactions" of this Annual Report on Form 10-K.

Net cash used in financing activities was $177.7 million in 2012 compared to $238.9 million in 2011. The decrease in cash used in financing activities was primarily attributable to the proceeds from the $250 million term loan completed on May 23, 2012 and net borrowings under our credit facility during 2012, partially offset by the repayment of the $300 million term loan and $18.0 million in senior notes and increased distributions paid to partners in 2012.

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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 facilities and cash provided from the issuance of debt or equity. The following table provides details regarding our contractual cash obligations as of December 31, 2012 (in thousands):

Contractual Obligations	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	$ 791,000	$ 18,000	$ 266,750	$ 361,250	$ 145,000
Future interest obligations(1)	119,564	33,147	54,615	27,038	4,764
Operating leases	6,010	1,653	1,854	1,820	683
Capital leases(2)	26,394	2,346	4,829	4,390	14,829
Purchase obligations for capital projects	96,926	96,926			
Coal purchase commitments	6,680	6,680			
Reclamation obligations(3)	155,576	3,192	4,155	24,869	123,360
Workers' compensation and pneumoconiosis benefit(3)	304,237	15,619	23,204	19,182	246,232
	$ 1,506,387	$ 177,563	$ 355,407	$ 438,549	$ 534,868

(1) Interest on variable-rate, long-term debt was calculated using rates elected by us at December 31, 2012 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 $2.4 million to the defined benefit pension plan ("Pension Plan") during 2013.

In addition to the above described capital expenditures related to our operating activities, we currently anticipate funding to White Oak during 2013 and 2014 approximately $125.7 million and $61.7 million, respectively, for reserve acquisitions, reserve development, surface facility financing and additional equity investment related to our participation in the White Oak Mine No. 1 development project.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include 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 any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

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, 2012 (in millions):

	Reclamation Obligation	Workers' Compensation Obligation	Other	Total
Surety bonds	$ 76.0	$ 39.9	$ 5.7	$ 121.6
Letters of credit		41.5	12.7	54.2

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Our continuing involvement in our unconsolidated affiliate, White Oak, will primarily consist of our support of the longwall mine currently under development in southern Illinois. We have committed to fund 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 $15.3 million for the year ended December 31, 2012 and expect to incur further allocated losses on our equity investment in White Oak over the next twelve months as White Oak continues in the development stages of its operations. For more information on the White Oak transactions, please read "Part II. Item 8. Financial Statements and Supplementary Data Note 12. White Oak Transactions" of this Annual Report on Form 10-K.

Capital Expenditures

Capital expenditures increased to $424.6 million in 2012 compared to $321.9 million in 2011. See our discussion of "Cash Flows" above concerning this increase in capital expenditures.

We currently project average estimated annual maintenance capital expenditures over the next five years of approximately $5.70 per ton produced. Our anticipated total capital expenditures for 2013 are estimated in a range of $370.0 to $400.0 million. Management anticipates funding 2013 capital requirements with our December 31, 2012 cash and cash equivalents of $28.3 million, future cash flows from operations, borrowings under revolving credit 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

During October 2012, we completed our annual property and casualty insurance renewal with various insurance coverages effective October 1, 2012. The aggregate maximum limit in the commercial property program is $100.0 million per occurrence excluding a $1.5 million deductible for property damage, a 90-day waiting period for underground business interruption 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.

Debt Obligations

Notes Offering and Credit Facility

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 million and a term loan (the "Term Loan") in the aggregate principal amount of $250 million (collectively, the Revolving Credit Facility and Term Loan are referred to as the "Credit Facility"). The Credit Facility replaces the $142.5 million revolving credit facility that was scheduled to mature September 25, 2012 and the $300 million term loan agreement dated December 29, 2010 that was prepaid and terminated early on May 23, 2012. The aggregate unpaid principal amount of $300 million and all unpaid interest was repaid using the proceeds of the Term Loan and borrowings under the Revolving Credit Facility. Our Intermediate Partnership did not incur any early termination penalties in connection with the prepayment of the term loan. 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 1.86% on borrowings outstanding as of

December 31, 2012. The Credit Facility matures May 23, 2017, at which time all amounts outstanding are required to be repaid. Interest is payable quarterly, with principal of the Term Loan due as follows: commencing with the quarter ending June 30, 2014 and for each quarter thereafter ending on March 31, 2016; 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. 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 will become due and payable.

At December 31, 2012, we had borrowings of $155.0 million and $23.5 million of letters of credit outstanding with $521.5 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 0.25% 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 of previously deferred debt issuance cost associated with our previous $300 million term loan.

Senior Notes. Our Intermediate Partnership has $36.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in two remaining equal annual installments of $18.0 million with interest payable semi-annually ("Senior Notes").

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 Senior Notes, 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, the incurrence of additional indebtedness and liens, the sale of assets, the making of investments, the entry into mergers and consolidations and the entry into 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 1.3 to 1.0 and 16.8 to 1.0, respectively, for the trailing twelve months ended December 31, 2012. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2012.

Other. In addition to the letters of credit available under the Revolving 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, 2012, we had $30.7 million in letters of

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credit outstanding under agreements with these two banks. SGP previously guaranteed $5.0 million of these outstanding letters of credit. On May 4, 2011, we entered into an amendment, dated as of October 2, 2010, which released SGP from its guarantee of these outstanding letters of credit.

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 our 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, 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.

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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 $77.0 million and $73.2 million for these costs at December 31, 2012 and 2011, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2012 approximately $6.6 million, which would have a corresponding increase in operating expenses.

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 $61.0 million and $55.6 million for these benefits at December 31, 2012 and 2011, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2012 by approximately $1.2 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 annually 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. For more information please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Health Care Reform," above.

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

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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% and 7.90% at December 31, 2012 and 2011, respectively. Our expected long-term rate of return used to determine our pension expense was 7.90% and 8.35% for the years ended December 31, 2012 and 2011, respectively. 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 8.5%, 10.0% invested in international equities with an expected long-term rate of return of 3.3% and 20.0% invested in fixed income securities with an expected long-term rate of return of 6.0%. 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 14.8% and (2.7)% for the years ended December 31, 2012 and 2011, respectively. Lowering the expected long-term rate of return assumption by 1.0% (from 7.90% to 6.90%) at December 31, 2011 would have increased our pension expense for the year ended December 31, 2012 by approximately $0.5 million; and

- Our weighted average discount rate used to determine our pension liability was 3.99% and 4.49% at December 31, 2012 and 2011, respectively. Our weighted average discount rate used to determine our pension expense was 4.49% and 5.56% at December 31, 2012 and 2011, 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 4.49% to 3.99%) at December 31, 2011 would have increased our pension expense for the year ended December 31, 2012 by approximately $0.1 million.

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 5. Asset Impairment Charge" of this Annual Report on Form 10-K). No impairment charges were recorded in 2011 and 2010.

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, 2012 and 2011, capitalized mine development costs were $32.6 million and $73.8 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.

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 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 $84.8 million and $72.3 million for these costs are recorded at December 31, 2012 and 2011, respectively. The liability for asset retirement and closing procedures is sensitive to changes in cost estimates and estimated mine lives.

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 $12.5 million and $13.5 million for the years ended December 31, 2012 and 2011, respectively. The adjustments to the liability for the year ended December 31, 2012 were primarily attributable to a liability associated with the Onton mine acquisition and increased refuse site reclamation disturbances with new mine development work at Tunnel Ridge and Gibson South, 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 and fluctuations in projected mine life estimates over all locations. These increases were offset in part by reductions for completed reclamation work at certain inactive locations.

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 $70.7 million and $71.3 million at December 31, 2012 and 2011.

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We estimate that the aggregate undiscounted cost of final mine closure is approximately $155.6 million at December 31, 2012. 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 up to an aggregate of $500 million of debt or equity securities. At March 1, 2013, we had not utilized any amounts available under this registration statement.

Related-Party Transactions

The Board of Directors and its conflicts committee ("Conflicts Committee") review each of our related-party transactions 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 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, $0.4 million and $0.3 million for the years ended December 31, 2012, 2011 and 2010, respectively, from AHGP and $0.1 million, $0.2 million and $0.2 million from ARH II for the years ended December 31, 2012, 2011 and 2010, 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 $1.2 million, $0.7 million and $1.3 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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Managing General Partner Contributions

During December 2012 and 2011, an affiliated entity controlled by Mr. Craft contributed $2.0 million and $5.0 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 currently under construction. 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. For more information about the White Oak Transactions, please read "Item 8. Financial Statements and Supplementary Data Note 12. White Oak Transactions" 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 a time-sharing agreement between SGP Land, LLC ("SGP Land"), another subsidiary of SGP, and us. In consideration for this merger, we paid SGP approximately $8.0 million cash at closing.

ASI has agreements with SGP Land, and with Mr. Craft, providing for the use of ASI aircraft by SGP Land and Mr. Craft. SGP and Mr. Craft paid us $0.1 million for aircraft usage in 2012 as a result of these agreements. In addition, Alliance Coal has an agreement with JC Land LLC ("JC Land"), an entity owned by Mr. Craft, providing for the use of JC Land's aircraft by Alliance Coal. As a result of this agreement, we paid JC Land $0.1 million for aircraft usage in 2012.

We reimbursed SGP Land $0.3 million, $1.0 million and $0.8 million for the years ended December 31, 2012, 2011 and 2010, respectively 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 $0.4 million, $0.3 million and $0.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. As of December 31, 2012, $2.3 million of advance minimum royalties paid under the lease is available for recoupment, and management expects that it will be recouped against future production.

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, 2012, 2011 and 2010. As of December 31, 2012, $20.2 million of advance minimum royalties paid under the lease is available for recoupment and management expects that it will be recouped against future production. In August 2010, the coal lease was amended to include approximately 34.4 million additional clean tons of recoverable coal reserves in the proven and probable categories.

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 has 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, 2012, 2011 and 2010.

We have a noncancelable lease arrangement for the Gibson North mine's coal preparation plant and ancillary facilities with SGP. Based on the terms of the original lease, we made monthly payments of approximately $0.2 million through January 2011. Effective February 1, 2011, the lease was amended to extend the term through January 2017 and modify other terms, including reducing the monthly payments to approximately $50,000. The lease arrangement is considered a capital lease based on the terms of the new arrangement. Lease payments for the years ended December 31, 2012, 2011 and 2010 were $0.6 million, $0.8 million and $2.6 million, respectively.

We have agreements with two banks to provide letters of credit in an aggregate amount of $31.1 million (see "Item 8. Financial Statements and Supplementary Data Note 8. Long-Term Debt" of this Annual Report on Form 10-K). SGP previously guaranteed $5.0 million of these outstanding letters of credit. These guarantees were released on May 4, 2011.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $248.7 million and $221.9 million at December 31, 2012 and 2011, 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

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. Any future inflationary or deflationary pressures could adversely affect the results of our operations. Please see "Item 1A. Risk Factors."

New Accounting Standards

New Accounting Standards Issued and Adopted

In May 2011, the FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* ("ASU 2011-04"). ASU 2011-04 amends FASB ASC 820, *Fair Value Measurement*, to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements. ASU 2011-04 was effective for fiscal years, and interim periods within those years, beginning after December 15,

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2011. The adoption of ASU 2011-04 did not have a material impact on our consolidated financial statements.

In June 2011, the FASB issued ASU 2011-05, *Presentation of Comprehensive Income* ("ASU 2011-05"). ASU 2011-05 removes the presentation options in FASB ASC 220, *Comprehensive Income*, and requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. Under the two statement approach, the first statement includes components of net income, and the second statement includes components of other comprehensive income ("OCI"). ASU 2011-05 does not change the items that must be reported in OCI. ASU 2011-05 was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and its provisions had to be applied retrospectively for all periods presented in the financial statements. In December 2011, the FASB issued ASU 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05* ("ASU 2011-12"), which indefinitely deferred a provision of ASU 2011-05 that required entities to present reclassification adjustments out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which OCI is presented. The adoption of ASU 2011-05 did not have a material impact on our consolidated financial statements.

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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 94.2% of our sales tonnage, including approximately 94.6% of our medium-and high-sulfur coal sales tonnage, being sold under long-term contracts in 2012. Virtually all of the long-term coal supply agreements are subject to price adjustment provisions, which permit an increase or decrease periodically in the contract price to principally reflect changes in specified price indices or items such as taxes, royalties or actual production costs resulting from regulatory changes. 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 January 29, 2013, our nominal commitment under long-term contracts was approximately 38.5 million tons in 2013, 30.7 million tons in 2014, 23.4 million tons in 2015 and 18.7 million tons in 2016.

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 2012, approximately 93.1% 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 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 $155.0 million in borrowings under the Revolving Credit Facility and $250.0 million outstanding under the Term Loan at December 31, 2012. A one percentage point increase in the interest rates related to the Revolving Credit Facility and Term Loan would result in an annualized increase in 2013 interest expense of $4.1 million, based on borrowing levels at December 31, 2012. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a decrease of approximately $13.3 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, 2012 and 2011.

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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, 2012	2013	2014	2015	2016	2017	Thereafter	Total	Fair Value December 31, 2012
Fixed rate debt	$ 18,000	$ 18,000	$ 205,000	$	$	$ 145,000	$ 386,000	$ 430,849
Weighted average interest rate	6.61%	6.52%	6.54%	6.72%	6.72%	6.72%		
Variable rate debt	$	$ 18,750	$ 25,000	$ 156,250	$ 205,000	$	$ 405,000	$ 403,411
Weighted average interest rate(1)	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%		

Expected Maturity Dates as of December 31, 2011	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value December 31, 2011
Fixed rate debt	$ 18,000	$ 18,000	$ 18,000	$ 205,000	$	$ 145,000	$ 404,000	$ 444,386
Weighted average interest rate	6.68%	6.61%	6.52%	6.54%	6.72%	6.72%		
Variable rate debt	$	$ 60,000	$ 75,000	$ 165,000	$	$	$ 300,000	$ 302,133
Weighted average interest rate(1)	2.30%	2.30%	2.30%	2.30%				

(1) Interest rate on variable rate debt equal to the rate elected by us as of December 31, 2012, 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, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows, and partners' capital for each of the two years in the period ended December 31, 2012. Our audits also included the 2012 and 2011 information in 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, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the 2012 and 2011 information in 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 2012 and 2011 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, 2012, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 1, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated statements of income, comprehensive income, cash flows, and Partners' capital of Alliance Resource Partners, L.P. and subsidiaries (the "Partnership") for the year ended December 31, 2010. Our audits also included the financial statement schedule for the year ended December 31, 2010 listed in the Index at Item 15. These financial statements and the financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 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 audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of the operations and the cash flows of Alliance Resource Partners, L.P. and subsidiaries for the year ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte and Touche LLP

Tulsa, Oklahoma
February 28, 2011
(March 1, 2013 related to the change in presentation of comprehensive income as described in Note 2)

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2012 AND 2011
(In thousands, except unit data)

	December 31, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 28,283	$ 273,528
Trade receivables	172,724	128,643
Other receivables	1,019	3,525
Due from affiliates	658	5,116
Inventories	46,660	33,837
Advance royalties	11,492	7,560
Prepaid expenses and other assets	20,476	11,945
Total current assets	281,312	464,154
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	2,361,863	1,974,520
Less accumulated depreciation, depletion and amortization	(832,293)	(793,200)
Total property, plant and equipment, net	1,529,570	1,181,320
OTHER ASSETS:		
Advance royalties	23,267	27,916
Due from affiliate	3,084	
Equity investments in affiliates	88,513	40,118
Other long-term assets	30,226	18,010
Total other assets	145,090	86,044
TOTAL ASSETS	$ 1,955,972	$ 1,731,518
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 100,174	$ 96,869
Due to affiliates	327	494
Accrued taxes other than income taxes	19,998	15,873
Accrued payroll and related expenses	38,501	35,876
Accrued interest	1,435	2,195
Workers' compensation and pneumoconiosis benefits	9,320	9,511
Current capital lease obligations	1,000	676
Other current liabilities	19,572	15,326
Current maturities, long-term debt	18,000	18,000
Total current liabilities	208,327	194,820
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	773,000	686,000
Pneumoconiosis benefits	59,931	54,775
Accrued pension benefit	31,078	27,538
Workers' compensation	68,786	64,520
Asset retirement obligations	81,644	70,836
Long-term capital lease obligations	18,613	2,497
Other liabilities	9,147	6,774
Total long-term liabilities	1,042,199	912,940
Total liabilities	1,250,526	1,107,760

COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL:		
Limited Partners Common Unitholders 36,874,949 and 36,775,741 units outstanding, respectively	1,020,823	943,325
General Partners' deficit	(273,113)	(279,107)
Accumulated other comprehensive loss	(42,264)	(40,460)
Total Partners' Capital	705,446	623,758
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,955,972	$ 1,731,518

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, 2012, 2011 AND 2010
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2012	**2011**	**2010**
SALES AND OPERATING REVENUES:			
Coal sales	$ 1,979,437	$ 1,786,089	$ 1,551,539
Transportation revenues	22,034	31,939	33,584
Other sales and operating revenues	32,830	25,532	24,942
Total revenues	2,034,301	1,843,560	1,610,065
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	1,303,291	1,131,750	1,009,935
Transportation expenses	22,034	31,939	33,584
Outside coal purchases	38,607	54,280	17,078
General and administrative	58,737	52,334	50,818
Depreciation, depletion and amortization	218,122	160,335	146,881
Asset impairment charge	19,031		
Total operating expenses	1,659,822	1,430,638	1,258,296
INCOME FROM OPERATIONS	374,479	412,922	351,769
Interest expense (net of interest capitalized of $8,436, $14,797 and $888, respectively)	(28,684)	(21,954)	(30,062)
Interest income	229	375	200
Equity in loss of affiliates, net	(14,650)	(3,404)	
Other income	3,115	983	851
INCOME BEFORE INCOME TAXES	334,489	388,922	322,758
INCOME TAX EXPENSE (BENEFIT)	(1,082)	(431)	1,741
NET INCOME	$ 335,571	$ 389,353	$ 321,017
GENERAL PARTNERS' INTEREST IN NET INCOME	$ 106,837	$ 86,251	$ 73,172
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 228,734	$ 303,102	$ 247,845
BASIC AND DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 6.12	$ 8.13	$ 6.68
DISTRIBUTIONS PAID PER LIMITED PARTNER UNIT	$ 4.1625	$ 3.6275	$ 3.205
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING BASIC AND DILUTED	36,863,022	36,769,126	36,710,431

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, 2012, 2011 AND 2010
(In thousands)

	Year Ended December 31,		
	2012	**2011**	**2010**
NET INCOME	$ 335,571	$ 389,353	$ 321,017
OTHER COMPREHENSIVE INCOME:			
Defined benefit pension plan			
Net actuarial gain (loss)	(6,524)	(17,483)	5,110
Amortization of actuarial loss	1,788	537	366
Total defined benefit pension plan adjustments	(4,736)	(16,946)	5,476
Pneumoconiosis benefits			
Net actuarial gain (loss)	2,156	(4,570)	(6,872)
Amortization of actuarial (gain) loss	776	(223)	(176)
Total pneumoconiosis benefits adjustments	2,932	(4,793)	(7,048)
OTHER COMPREHENSIVE INCOME	(1,804)	(21,739)	(1,572)
TOTAL COMPREHENSIVE INCOME	$ 333,767	$ 367,614	$ 319,445

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011 AND 2010
(In thousands)

	Year Ended December 31,		
	2012	**2011**	**2010**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 335,571	$ 389,353	$ 321,017
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	218,122	160,335	146,881
Non-cash compensation expense	7,428	6,235	4,051
Asset retirement obligations	2,853	2,546	2,579
Coal inventory adjustment to market	2,978	386	498
Loss on retirement of vertical hoist conveyor system			1,204
Equity in loss of affiliates, net	14,650	3,404	
Net loss on foreign currency transaction			274
Net (gain) loss on sale of property, plant and equipment	147	(634)	234
Asset impairment charge	19,031		
Other	(3,815)	1,488	1,448
Changes in operating assets and liabilities:			
Trade receivables	(44,081)	(15,701)	(21,780)
Other receivables	1,960	(1,832)	(689)
Inventories	(16,119)	(2,818)	31,412
Prepaid expenses and other assets	(8,531)	(1,921)	(1,223)
Advance royalties	765	(3,225)	(1,820)
Accounts payable	7,312	21,890	8,055
Due to affiliates	4,291	1,717	1,062
Accrued taxes other than income taxes	4,125	1,972	3,124
Accrued payroll and related benefits	2,625	5,103	8,670
Pneumoconiosis benefits	5,961	4,944	3,647
Workers' compensation	4,075	5,717	4,583
Other	(3,492)	(4,976)	7,361
Total net adjustments	220,285	184,630	199,571
Net cash provided by operating activities	555,856	573,983	520,588
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(424,631)	(321,920)	(289,874)
Changes in accounts payable and accrued liabilities	(4,007)	11,640	(7,480)
Proceeds from sale of property, plant and equipment	114	1,526	381
Purchases of equity investments in affiliate	(59,800)	(42,700)	
Payment for acquisition of business	(100,000)		
Payments to affiliate for acquisition and development of coal reserves	(34,601)	(50,800)	
Advances/loans to affiliate	(5,229)		
Payments from affiliate	4,229		
Other	546	1,146	1,982
Net cash used in investing activities	(623,379)	(401,108)	(294,991)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under term loan	250,000		300,000
Borrowings under revolving credit facilities	278,800		95,000
Payments under revolving credit facilities	(123,800)		(95,000)
Payment on term loan	(300,000)		
Payment on long-term debt	(18,000)	(18,000)	(18,000)
Payments on capital lease obligations	(943)	(812)	(324)
Payment of debt issuance costs	(4,272)		(1,417)

Net settlement of employee withholding taxes on vesting of Long-Term Incentive Plan	(3,734)	(2,324)	(1,265)
Cash contributions by General Partners	2,150	87	43
Distributions paid to Partners	(257,923)	(217,860)	(186,354)
Net cash (used in) provided by financing activities	(177,722)	(238,909)	92,683
EFFECT OF CURRENCY TRANSLATION ON CASH			(274)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(245,245)	(66,034)	318,006
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	273,528	339,562	21,556
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 28,283	$ 273,528	$ 339,562

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, 2012, 2011 AND 2010
(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, 2010	36,661,029	$ 630,165	$ (293,153)	$ (17,149)	$ 1,117	$ 320,980
Comprehensive income:						
Net income		247,845	73,172			321,017
Actuarially determined long-term liability adjustments				(1,572)		(1,572)
Total comprehensive income						319,445
Deconsolidation of Mid-America Carbonates, LLC					(1,117)	(1,117)
Issuance of units to Long-Term Incentive Plan participants upon vesting	55,826	(1,265)				(1,265)
Common unit-based compensation under Long-Term Incentive Plan		4,051				4,051
General Partners contributions			43			43
Distributions on common unit-based compensation		(1,286)				(1,286)
Distributions to Partners		(117,635)	(67,433)			(185,068)
Balance at December 31, 2010	36,716,855	761,875	(287,371)	(18,721)		455,783
Comprehensive income:						
Net income		303,102	86,251			389,353
Actuarially determined long-term liability adjustments				(21,739)		(21,739)
Total comprehensive income						367,614
Issuance of units to Long-Term Incentive Plan participants upon vesting	58,886	(2,324)				(2,324)
Common unit-based compensation		6,235				6,235
Reclassification of SERP and Deferred Compensation Plans (Note 15)		9,223				9,223
General Partners contributions (Note 13)			5,087			5,087
Distributions on common unit-based compensation		(1,433)				(1,433)
Distributions to Partners		(133,353)	(83,074)			(216,427)
Balance at December 31, 2011	36,775,741	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	99,208	(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	36,874,949	$	1,020,823	$	(273,113)	$	(42,264)	$	$	705,446

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, 2012, 2011 AND 2010

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 15,544,169 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 Properties, LLC, Alliance Resource Properties, LLC, ("Alliance Resource Properties"), ARP Sebree, LLC, ARP Sebree South, LLC, Alliance WOR Properties, LLC ("WOR Properties"), Alliance Service, Inc. ("ASI"), Alliance WOR Processing, LLC ("WOR Processing"), Backbone Mountain, LLC, CR Services, LLC ("CR Services"), 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

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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 ("Steamport"), Tunnel Ridge, LLC ("Tunnel Ridge"), Warrior Coal, LLC ("Warrior"), Webster County Coal, LLC ("Webster County Coal"), and White County Coal, LLC ("White County Coal").

The accompanying consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of December 31, 2012 and 2011, 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, 2012. All of our intercompany transactions and accounts have been eliminated.

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 and accounts payable approximate fair value because of the short maturity of those instruments. At December 31, 2012 and 2011, the estimated fair value of long-term debt, including current maturities, was approximately $834.3 million and $746.5 million, respectively (Note 9).

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 no restricted cash and cash equivalents at December 31, 2012 and 2011.

Cash Management The cash flows from operating activities section of our Consolidated Statements of Cash Flows reflects an adjustment for $10.3 million and $6.7 million representing book overdrafts at December 31, 2012 and 2011, respectively. We had no book overdrafts at December 31, 2010.

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. Depreciation and amortization are computed principally on the straight-line method based upon the estimated useful lives of the assets or the estimated life of each mine, whichever is less, ranging from 1 to 16 years. Depreciable lives for mining equipment and processing facilities range from 1 to 16 years. Depletable lives for mineral rights range from 2 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 current operations. 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, 2012 and 2011, land and mineral rights include $118.2 million and $66.9 million, respectively, representing the carrying value of coal reserves attributable to properties where we 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.

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, 2012 and 2011, capitalized mine development costs were $32.6 million and $73.8 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 5). No impairment charges were recorded in 2011 and 2010.

Intangible Assets Intangible assets subject to amortization include contracts with covenants not to compete, customer contracts acquired in a business combination and mining permits. Intangible assets are amortized on a straight-line basis over their useful life. Amortization expense attributable to intangible assets was $2.6 million, $1.4 million and $1.1 million for the years ending December 31, 2012, 2011 and 2010, respectively. Our intangible assets are included in other long-term assets on our consolidated balance sheets at December 31, 2012 and 2011. Our intangible assets at December 31, are summarized as follows (in thousands):

	December 31, 2012			December 31, 2011		
	Original Cost	Accumulated Amortization	Intangibles, Net	Original Cost	Accumulated Amortization	Intangibles, Net
Non-compete agreements	$ 15,236	$ (5,374)	$ 9,862	$ 14,036	$ (3,807)	$ 10,229
Customer contracts	6,171	(1,003)	5,168	120	(24)	96
Mining permits	3,843	(50)	3,793	3,000		3,000
Total	$ 25,250	$ (6,427)	$ 18,823	$ 17,156	$ (3,831)	$ 13,325

Amortization expense attributable to intangible assets is estimated to be $3.0 million per year in 2013-2016 and $1.3 million in 2017.

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

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prepayments estimated to be nonrecoverable are expensed. Our advance royalties at December 31 are summarized as follows (in thousands):

	2012	2011
Advance royalties, affiliates (Note 19)	$ 22,509	$ 22,954
Advance royalties, third-parties	12,250	12,522
Total advance royalties	$ 34,759	$ 35,476

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 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 (Note 17).

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 us. Our subsidiary, ASI, is subject to federal and state income taxes. 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, 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, 2012 and 2011.

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

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("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, compensation increases, 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 Per Unit Basic net income per limited partner unit is determined by dividing net income available to Limited Partners by the weighted average number of outstanding common units. Diluted net income per unit is based on the combined weighted average number of common units and common unit equivalents outstanding (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 2012 and 2011, we determined there were no such material events or changes in circumstances that would indicate the carrying amount of such investments was not recoverable. Our equity method investments include our ownership interests in White Oak Resources LLC ("White Oak") (Note 12) and Mid-America Carbonates, LLC ("MAC").

New Accounting Standards Issued and Adopted In May 2011, the FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* ("ASU 2011-04"). ASU 2011-04 amends FASB ASC 820, *Fair Value Measurement*, to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements. ASU 2011-04 was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The adoption of ASU 2011-04 did not have a material impact on our consolidated financial statements.

In June 2011, the FASB issued ASU 2011-05, *Presentation of Comprehensive Income* ("ASU 2011-05"). ASU 2011-05 removes the presentation options in FASB ASC 220, *Comprehensive Income*, and requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. Under the two statement approach, the first statement includes components of net income, and the second statement includes components of other comprehensive income ("OCI"). ASU 2011-05 does not change the items that must be reported in OCI. ASU 2011-05 was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and its provisions had to be applied retrospectively for all periods presented in the financial statements. In December 2011, the FASB issued ASU 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05* ("ASU 2011-12"), which indefinitely deferred a provision of ASU 2011-05 that required entities to present reclassification adjustments out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which OCI is presented. The adoption of ASU 2011-05 did not have a material impact on our consolidated financial statements.

3. PATTIKI VERTICAL HOIST CONVEYOR SYSTEM FAILURE IN 2010

On May 13, 2010, White County Coal's Pattiki mine was temporarily idled following the failure of the vertical hoist conveyor system used in conveying raw coal out of the mine. Our operating expenses for the twelve months ended December 31, 2010 include $1.2 million for retirement of certain assets related to the failed vertical hoist conveyor system in addition to other repair and clean-up expenses that were not significant on a consolidated or segment basis. As the loss on the vertical hoist conveyor system did not exceed the deductible under our commercial property (including business interruption) insurance policies, we did not recover any amounts under such policies.

While the Pattiki mine was temporarily idled, we expanded coal production at our other coal mines in the region, including the addition of the seventh and eighth production units at the River View mine, to partially offset the loss of production from the Pattiki mine. Consequently, the temporary idling of the Pattiki mine in 2010 did not have a material adverse impact on our results of operations and cash flows. On July 19, 2010, the Pattiki mine resumed limited production while White County Coal continued to assess the effectiveness and reliability of the repaired vertical hoist conveyor system. On January 3, 2011, the Pattiki mine returned to full production capacity.

4. ACQUISITION OF BUSINESS

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.

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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

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 will be 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.

The following unaudited pro forma information for the ARLP Partnership has been prepared for illustrative purposes and assumes that the business combination occurred on January 1, 2011. The unaudited pro forma results have been prepared based upon Green River's historical results with respect to the business acquired and estimates of the effects of the transactions that we believe are reasonable and supportable. The results are not necessarily reflective of the consolidated results of operations had the acquisition actually occurred on January 1, 2011, nor are they indicative of future operating results.

	Year Ended December 31,	
	2012	**2011**
	(in thousands)	
Total revenues		
As reported	$ 2,034,301	$ 1,843,560
Pro forma	$ 2,061,644	$ 1,957,598
Net income		
As reported	$ 335,571	$ 389,353
Pro forma	$ 336,852	$ 400,727

The revenues and net income related to the acquired business are reflected in our consolidated statements of income beginning April 2, 2012 and totaled $81.6 million and $7.6 million, respectively, which are included in the total revenues and net income above for the year ended December 31, 2012.

The pro forma net income includes adjustments to depreciation, depletion and amortization to reflect the new basis in property, plant and equipment and intangible assets acquired, elimination of income tax expense, and the elimination of interest expense of Green River as its debt was paid off in conjunction with the acquisition. Acquisition costs related to the business acquired of $0.6 million were reclassified to the beginning of 2011 in preparation of the pro forma results, as the acquisition was assumed to have been completed January 1, 2011 for the pro forma presentation.

Synergies from the acquisition are not reflected in the pro forma results.

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5. ASSET IMPAIRMENT CHARGE

Pontiki's mining complex in Martin County, Kentucky was idled from August 29, 2012 to November 25, 2012. The Mine Safety and Health Administration ("MSHA") ordered the closure of the coal preparation plant and associated surface facilities at the Pontiki mining complex following the failure on August 23, 2012 of a belt line between two clean coal stacking tubes. MSHA required a comprehensive structural inspection of all the surface facilities by an independent bridge engineering firm before the surface facilities could be reopened. Although the Pontiki mining complex resumed operations to fulfill contractual obligations for the delivery of coal in 2013 under existing coal sales agreements, significant uncertainty remains regarding market demand and pricing for coal from Pontiki beyond 2013. This uncertainty along with the likelihood of future cost increases arising from stringent regulatory oversight places the long-term viability of Pontiki at significant risk. As a result of the above events, which included uncertainty around the future operations of the mine and the required additional repair costs, and our assessment of related risks, we concluded that indicators of impairment were present and the carrying value of the asset group representing the Pontiki mining complex ("Pontiki Assets") was not fully recoverable. We estimated the fair value of the Pontiki Assets and determined it was exceeded by the carrying value and accordingly, we recorded an asset impairment charge of $19.0 million in our Central Appalachian segment during the quarter ended September 30, 2012 to reduce the carrying value of the Pontiki Assets to their estimated fair value of $16.1 million. The fair value of the Pontiki Assets was determined using the market and cost valuation techniques and represents a Level 3 fair value measurement. The fair value analysis was based on the marketability of coal properties in the current market environment, discounted projected future cash flows, and estimated fair value of assets that could be sold or used at other operations. As these estimates incorporate certain assumptions, including replacement cost of equipment and marketability of coal reserves in the Central Appalachian region, and it is possible that the estimates may change in the future resulting in the need to adjust our determination of fair value. The asset impairment established a new cost basis on which depreciation, depletion and amortization is calculated for the Pontiki Assets.

6. INVENTORIES

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

	2012	2011
Coal	$ 14,763	$ 7,794
Supplies (net of reserve for obsolescence of $2,721 and $2,387, respectively)	31,897	26,043
Total inventory	$ 46,660	$ 33,837

7. PROPERTY, PLANT AND EQUIPMENT

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

	2012	2011
Mining equipment and processing facilities	$ 1,434,674	$ 1,213,458
Land and mineral rights	303,725	176,357
Buildings, office equipment and improvements	208,351	183,712
Construction in progress	129,720	171,957
Mine development costs	285,393	229,036
Property, plant and equipment, at cost	2,361,863	1,974,520
Less accumulated depreciation, depletion and amortization	(832,293)	(793,200)
Total property, plant and equipment, net	$ 1,529,570	$ 1,181,320

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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 $22.8 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 $3.8 million and $1.9 million as of December 31, 2012 and 2011, respectively, and amortization expense was $1.9 million, $0.8 million and $0.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. For information regarding the impairment of assets at the Pontiki mine, please see Note 5.

8. LONG-TERM DEBT

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

	2012	2011
Credit facility	$ 155,000	$
Senior notes	36,000	54,000
Series A senior notes	205,000	205,000
Series B senior notes	145,000	145,000
Term loan	250,000	300,000
	791,000	704,000
Less current maturities	(18,000)	(18,000)
Total long-term debt	$ 773,000	$ 686,000

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 million and a term loan (the "Term Loan") in the aggregate principal amount of $250 million (collectively, the Revolving Credit Facility and Term Loan are referred to as the "Credit Facility"). The Credit Facility replaces the $142.5 million revolving credit facility that was schedule to mature September 25, 2012 and the $300 million term loan agreement dated December 29, 2010 that was prepaid and terminated early on May 23, 2012. The aggregate unpaid principal amount of $300 million and all unpaid interest was repaid using the proceeds of the Term Loan and borrowings under the Revolving Credit Facility. Our Intermediate Partnership did not incur any early termination penalties in connection with the prepayment of the term loan. 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 1.86% on borrowings outstanding as of December 31, 2012. The Credit Facility matures May 23, 2017, at which time all amounts outstanding are required to be repaid. Interest is payable quarterly, with principal of the Term Loan due as follows: commencing with the quarter ending June 30, 2014 and for each quarter thereafter ending on March 31, 2016, 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. 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 will become due and payable.

At December 31, 2012, we had borrowings of $155.0 million and $23.5 million of letters of credit outstanding with $521.5 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 0.25% 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 of previously deferred debt issuance cost associated with our previous $300 million term loan.

Senior Notes. Our Intermediate Partnership has $36.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in two remaining equal annual installments of $18.0 million with interest payable semi-annually ("Senior Notes").

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 Senior Notes, 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, the incurrence of additional indebtedness and liens, the sale of assets, the making of investments, the entry into mergers and consolidations and the entry into 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 1.3 to 1.0 and 16.8 to 1.0, respectively, for the trailing twelve months ended December 31, 2012. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2012.

Other. In addition to the letters of credit available under the Revolving 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, 2012, we had $30.7 million in letters of credit outstanding under agreements with these two banks. SGP previously guaranteed $5.0 million of these outstanding letters of credit. On May 4, 2011, we entered into an amendment, dated as of October 2, 2010, which released SGP from its guarantee of these outstanding letters of credit.

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

Year Ending December 31,	
2013	$ 18,000
2014	36,750
2015	230,000
2016	156,250
2017	205,000
Thereafter	145,000
	$ 791,000

9. 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. 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 and accounts payable approximate fair value because of the short maturity of those instruments. At December 31, 2012 and 2011, the estimated fair value of our long-term debt, including current maturities, was approximately $834.3 million and $746.5 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 8). 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.

10. 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 $0.25 per unit ($1.00 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 $0.275 per unit, 25% of the amount we distribute in excess of $0.3125 per unit, and 50% of the amount we distribute in excess of $0.375 per unit.

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For the years ended December 31, 2012, 2011 and 2010, we allocated to our managing general partner incentive distributions of $102.1 million, $83.4 million and $66.8 million, respectively. The following table summarizes the quarterly per unit distribution paid during the respective quarter:

	Year		
	2012	2011	2010
First Quarter	$ 0.9900	$ 0.8600	$ 0.775
Second Quarter	$ 1.0250	$ 0.8900	$ 0.790
Third Quarter	$ 1.0625	$ 0.9225	$ 0.810
Fourth Quarter	$ 1.0850	$ 0.9550	$ 0.830

On January 29, 2013, we declared a quarterly distribution of $1.1075 per unit, totaling approximately $69.1 million (which includes our managing general partner's incentive distributions), on all our common units outstanding, which was paid on February 14, 2013, to all unitholders of record on February 7, 2013.

11. INCOME TAXES

Our subsidiary, ASI, is subject to federal and state income taxes. ASI's income is principally due to its subsidiary, Matrix Design. ASI has minor temporary differences between Matrix Design's financial reporting basis and the tax basis of its assets and liabilities. Components of income tax expense (benefit) are as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Current:			
Federal	$ (37)	$ (337)	$ 1,517
State	(183)	(75)	240
	(220)	(412)	1,757
Deferred:			
Federal	(753)	(17)	(14)
State	(109)	(2)	(2)
	(862)	(19)	(16)
Income tax expense (benefit)	$ (1,082)	$ (431)	$ 1,741

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,		
	2012	2011	2010
Income taxes at statutory rate	$ 117,057	$ 136,122	$ 112,966
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(117,767)	(136,257)	(111,345)
Increase/(decrease) resulting from:			
State taxes, net of federal income tax	(83)	(8)	162
Other	(289)	(288)	(42)
Income tax expense (benefit)	$ (1,082)	$ (431)	$ 1,741

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12. WHITE OAK TRANSACTIONS

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 currently under construction. The transactions 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 backstop equipment financing facility. 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 to White Oak $121.5 million between the Transaction Date and December 31, 2012. We expect to fund a total of approximately $300.5 million to $425.5 million from the Transaction Date through the next two to three years, which includes the funding made to White Oak through December 31, 2012 discussed above. On the Transaction Date, we also entered into a coal handling and services agreement. We expect to fund these additional commitments utilizing existing cash balances, future cash flows from operations, borrowings under credit facilities and cash provided from the issuance of debt or equity. The following information discusses each component of these transactions in further detail.

Hamilton County, Illinois Reserve Acquisition

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 are currently being developed for future 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. In 2011, subsequent to the Transaction Date, WOR Properties provided $17.0 million to White Oak for development of the acquired coal reserves. During the twelve months ended December 31, 2012, WOR Properties provided $34.6 million to White Oak for development of the acquired coal reserves, fulfilling its initial commitment for further development funding and has a remaining commitment of $54.6 million for additional coal reserve acquisitions and development funding. In conjunction with the Reserve Acquisition, WOR Properties entered into a Coal Mining Lease, Sublease and Development Agreement ("Coal Lease Agreement") with White Oak, which provides White Oak the rights to develop and mine the acquired reserves. The Coal Lease Agreement requires, 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 when coal sales begin and a fully recoupable minimum monthly royalty of $1.625 million during the period beginning January 1, 2015 and ending December 31, 2034. The lease term is through December 31, 2034, subject to certain renewal options for White Oak.

Equity Investment 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 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 $7.0 million of additional Series A Units between the Transaction Date and December 31, 2011, and $59.8 million of additional Series A Units during the twelve months ended December 31, 2012, bringing the total investment in Series A Units to $102.5 million at December 31, 2012.

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. Assuming a $150.0 million investment in Series A Units, WOR Processing's ownership interest in White Oak will be 20.0% and it will be entitled to receive 20.0% of all distributions subsequent to satisfaction of the Series A Units minimum return. 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, 2012 and 2011 was 14.6% and 6.6%, respectively, based upon currently outstanding voting units. The remainder of the equity ownership in White Oak, represented by Series 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. We continually review all rights provided to WOR Processing and us by various agreements with White Oak and continue to conclude 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 income/(loss) in our consolidated statements of income. As of December 31, 2012, WOR Processing had invested $102.5 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. White Oak made no distributions from the Transaction Date through December 31, 2012.

We record WOR Processing's equity in earnings or losses of affiliates under the HLBV method of accounting due to the preferences WOR Processing receives on distributions. Under the HLBV method, we determine WOR Processing's share of White Oak earnings 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 December 31, 2012 and 2011, we were allocated losses of $15.3 million and $4.3 million, respectively.

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 will 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 mine. 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. 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 but not limited to, 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 has utilized $3.0 million available under the Construction Loan as of December 31, 2012.

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.

13. NET INCOME 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 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 10). 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 $0.275 per unit, 25% of the amount we distributed in excess of $0.3125 per unit, and 50% of the amount we distribute in excess of $0.375 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 and net income used for calculating EPU and the weighted average units used in computing EPU for the years ended December 31, 2012, 2011 and 2010, respectively (in thousands, except per unit data):

	Year Ended December 31,		
	2012	2011	2010
Net income	$ 335,571	$ 389,353	$ 321,017
Adjustments:			
Managing general partner priority distributions	(104,168)	(85,066)	(68,114)
General partners' 2% equity ownership	(4,669)	(6,185)	(5,058)
General partners' special allocation of certain general and administrative expenses	2,000	5,000	
Limited partners' interest in Net income	228,734	303,102	247,845
Less:			
Distributions to participating securities	(2,095)	(1,985)	(1,244)
Undistributed earnings attributable to participating securities	(922)	(2,337)	(1,282)
Net income available to limited partners	$ 225,717	$ 298,780	$ 245,319
Weighted average limited partner units outstanding Basic and Diluted(1)	36,863	36,769	36,710
Basic and Diluted Net income per limited partner unit(1)	$ 6.12	$ 8.13	$ 6.68

(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, 2012 and 2011, LTIP, SERP and Deferred Compensation Plan units of 344,956 and 409,969, respectively, were considered anti-dilutive. For the year ended December 31, 2010, LTIP units of 232,042 were considered anti-dilutive.

During 2010, accounts under the Deferred Compensation Plan and SERP were payable to participants in cash only. As a result, the phantom units associated with these plans were not considered in the calculation of basic or diluted units during 2010. Effective January 1, 2011, settlement of accounts under these plans will be only in common units of ARLP (Note 15). As a result, phantom units associated with these plans were considered in the calculation of basic or diluted units for the years ended December 31, 2012 and 2011. The non-vested LTIP grants associated with the LTIP Plan continue to entitle the LTIP participants to receive ARLP common units and accordingly are included in the calculation of basic and diluted units (to the extent of EPU dilution).

During 2012 and 2011, our managing general partner made a capital contribution of $2.0 million and $5.0 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 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

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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 $18.9 million, $15.6 million and $13.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. The increases in contribution expense are primarily attributable to increased headcount and higher salaries and wages included in the matching calculation.

Defined Benefit Plan Eligible employees at certain of our mining operations participate in a defined benefit plan (the "Pension Plan") that we sponsor. The benefit formula for the Pension Plan is a fixed-dollar unit based on years of service. Effective during 2008, new employees of these participating operations are no longer eligible to participate in the Pension Plan, but are eligible to participate in the PSSP that we sponsor. Additionally, certain employees participating in the Pension Plan, for some of those participating operations, had the one-time option during 2008 to remain in the Pension Plan or participate in enhanced benefit provisions under the PSSP.

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2012 and 2011 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements at December 31, 2012 and 2011, respectively (dollars in thousands):

	2012	2011
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 73,730	$ 57,278
Service cost	2,682	2,312
Interest cost	3,246	3,184
Actuarial loss	8,318	12,260
Benefits paid	(1,508)	(1,304)
Benefit obligations at end of year	86,468	73,730
Change in plan assets:		
Fair value of plan assets at beginning of year	46,192	43,982
Employer contribution	5,029	4,860
Actual return on plan assets	5,677	(1,346)
Benefits paid	(1,508)	(1,304)
Fair value of plan assets at end of year	55,390	46,192
Funded status at the end of year	$ (31,078)	$ (27,538)
Amounts recognized in balance sheet:		
Non-current liability	$ (31,078)	$ (27,538)
	$ (31,078)	$ (27,538)
Amounts recognized in accumulated other comprehensive income consists of:		
Net actuarial loss	$ (33,356)	$ (28,620)

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	2012	2011
Weighted-average assumptions to determine benefit obligations as of December 31,		
Discount rate	3.99%	4.49%
Expected rate of return on plan assets	8.00%	7.90%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,		
Discount rate	4.49%	5.56%
Expected return on plan assets	7.90%	8.35%

The actuarial loss component of the change in benefit obligation in 2012 was primarily attributable to a decrease in the discount rate partially offset by an increase in the actual rate of return on plan assets compared to December 31, 2011. The actuarial loss component of the change in benefit obligation in 2011 was primarily attributable to a decrease in the discount rate and the actual rate of return on plan assets compared to December 31, 2010.

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 8.5%, 10.0% invested in international equities with an expected long-term rate of return of 3.3% and 20.0% invested in fixed income securities with an expected long-term rate of return of 6.0%. Expected long-term rate of return is based on a 20-year-average annual total return for each investment group. The actual return on plan assets was 14.8% and (2.7)% for the years ended December 31, 2012 and 2011, respectively.

	2012	2011	2010
		(in thousands)	
Components of net periodic benefit cost:			
Service cost	$ 2,682	$ 2,312	$ 2,214
Interest cost	3,246	3,184	2,924
Expected return on plan assets	(3,882)	(3,877)	(3,270)
Amortization of net loss	1,788	537	366
Net periodic benefit cost	$ 3,834	$ 2,156	$ 2,234

	2012	2011
	(in thousands)	
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive income:		
Net actuarial loss	$ (6,524)	$ (17,483)
Reversal of amortization item:		
Net actuarial loss	1,788	537
Total recognized in accumulated other comprehensive loss	(4,736)	(16,946)
Net periodic benefit cost	(3,834)	(2,156)
Total recognized in net periodic benefit cost and accumulated other comprehensive loss	$ 8,570	$ 19,102

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Estimated future benefit payments as of December 31, 2012 are as follows (in thousands):

Year Ending December 31,	
2013	$ 1,814
2014	2,046
2015	2,341
2016	2,641
2017	2,967
2018 - 2022	21,171
	$ 32,980

We expect to contribute $2.4 million to the Pension Plan in 2013. The estimated net actuarial loss for the Pension Plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the 2013 fiscal year is $2.2 million.

On July 6, 2012, new federal legislation entitled Moving Ahead for Progress in the 21st Century Act was passed, which includes a provision aimed at stabilizing the interest rates used to calculate pension plan liabilities for pension funding purposes. We are currently evaluating the impact of this legislation; however, we anticipate that as a result of this new legislation, we will not make any further contributions during 2013 beyond the $2.4 million noted above.

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.

We had unfunded benefit obligations of approximately $31.1 million and $27.5 million at December 31, 2012 and 2011, 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 includes mutual funds, collective funds, or the direct investment in individual stocks,

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bonds or cash equivalent investments, including: (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 under unusual market conditions: (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,	**2012**	**2011**
Domestic equity securities	64%	64%
Foreign equity securities	16%	16%
Fixed income securities/cash	20%	20%
	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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14. EMPLOYEE BENEFIT PLANS

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, 2012			December 31, 2011		
	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	$ 652	$	$	$ 467	$	$
Equity securities(a):						
U.S. large-cap growth	6,210			5,404		
U.S. large-cap value	8,219			6,744		
Fixed income securities:						
U.S. Treasury securities(b)	1,781			1,815		
Corporate bonds(c)		2,266			2,093	
Taxable municipal bonds(c)		202			315	
International bonds(c)		579			528	
Equity mutual funds(d):						
U.S. large-cap growth		3,458			3,902	
U.S. large-cap value		1,661			2,628	
U.S. large-cap blend		2,180				
U.S. mid-cap growth		4,497			3,688	
U.S. mid-cap value		4,439			3,782	
U.S. small-cap growth		1,099			1,887	
U.S. small-cap value		1,158			1,907	
U.S. small-cap blend		2,232				
International		5,185			5,513	
International small/mid-cap blend		1,686				
Emerging Markets		2,241			1,849	
Fixed income mutual funds(d):						
Corporate bond		799			602	
Mortgage backed-securities		1,265			1,037	
Short term investment grade bond		1,673				
Intermediate investment grade bond		1,023			1,444	
High yield bond		553			515	
International bond		262			242	
Stock market index options(e):						
Puts		63			116	
Calls		(53)			(361)	
Accrued income(f)		60			75	
Total	$ 16,862	$ 38,528	$	$ 14,430	$ 31,762	$

(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, 2012.

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.

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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 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 25, 2012, the Compensation Committee determined that the vesting requirements for the 2009 grants of 9,125 restricted units (which is net of 500 forfeitures) and the grants issued during the three months ended December 31, 2008 of 135,305 restricted units (net of 5,840 forfeitures) had been satisfied as of January 1, 2012. As a result of this vesting, on February 14, 2012, we issued 93,938 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 23, 2013, the Compensation Committee authorized additional grants of 156,575 restricted units, of which 146,725 were granted.

During the years ended December 31, 2012, 2011, and 2010, we issued grants of 107,114 units, 108,416 units and 138,130 units, respectively. Grants issued during the year ended December 31, 2012 vest on January 1, 2015. Grants issued during the year ended December 31, 2011 vest on January 1, 2014. Grants issued during the year ended December 31, 2010 vest on January 1, 2013. Vesting of all grants is subject to the satisfaction of certain financial tests, which management currently believes is probable. As of December 31, 2012, 12,782 of these outstanding LTIP grants have been forfeited. On January 23, 2013, the Compensation Committee determined that the vesting requirements for the 2010 grants of 130,102 restricted units (which is net of 8,028 forfeitures) had been satisfied as of January 1, 2013. As a result of this vesting, on February 15, 2013, we issued 82,400 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. After consideration of the January 1, 2013 vesting and subsequent issuance of 82,400 common units, 2.2 million units remain available for issuance in the future, assuming that all grants issued in 2011 and 2012 and currently outstanding are settled with common units, without reduction for tax withholding, and no future forfeitures occur.

For the years ended December 31, 2012, 2011 and 2010, our LTIP expense was $6.4 million, $5.3 million and $4.1 million, respectively. The total obligation associated with the LTIP as of December 31, 2012 and 2011 was $12.1 million and $9.6 million, respectively, and is included in limited partners' capital in our consolidated balance sheets.

The fair value of the 2012, 2011 and 2010 grants is based upon the intrinsic value at the date of grant, which was $77.71, $66.84 and $39.59 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, 2012 is as follows:

Non-vested grants at January 1, 2012	384,218
Granted	107,114
Vested	(144,430)
Forfeited	(6,024)
Non-vested grants at December 31, 2012	340,878

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As of December 31, 2012, there was $7.8 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, 2012, the intrinsic value of the non-vested LTIP grants was $19.8 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.

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.

Amounts that were payable under either the SERP or Deferred Compensation Plan on or prior to January 1, 2011, were paid in either cash or common units of ARLP. Effective for amounts that become payable after January 1, 2011, both the Deferred Compensation Plan and the SERP require that vested benefits be paid to participants only in common units of ARLP, and therefore the phantom units now qualify for equity award accounting treatment. As a result, we reclassified a total of $9.2 million of obligations for the SERP and the Deferred Compensation Plan from due to affiliates and other long-term liabilities to partners' capital in our consolidated balance sheets as required under FASB ASC 718, *Compensation-Stock Compensation*, on January 1, 2011. For the years ended December 31, 2012 and 2011, SERP and Deferred Compensation Plan participant notional account balances were credited with a total of 13,791 and 13,725 phantom units, respectively, and the fair value of these phantom units was $60.91 and $72.83, respectively, on a weighted-average basis. Total SERP and Deferred Compensation Plan expense was approximately $0.8 million, $1.0 million and $3.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

As of December 31, 2012, there were 162,496 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 $9.4 million. As of December 31, 2012, the total obligation associated with the SERP and Deferred Compensation Plan was $10.7 million and is included in the partners' capital-limited partners line item in our consolidated balance sheets. On February 14, 2013, we issued 5,705 ARLP common units to directors under the Deferred Compensation Plan.

16. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Cash Paid For:			
Interest	$ 35,833	$ 36,188	$ 30,787
Income taxes	$	$ 300	$ 1,803
Non-Cash Activity:			
Accounts payable for purchase of property, plant and equipment	$ 20,972	$ 24,979	$ 13,339
Market value of common units vested in Long-Term Incentive Plan before minimum statutory tax withholding requirements	$ 11,070	$ 6,572	$ 3,396
Assets acquired by capital lease	$	$ 3,525	$
Acquisition of business:			
Fair value of assets assumed	$ 126,639	$	$
Cash paid	(100,000)		
Fair value of liabilities assumed	$ 26,639	$	$

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 ("SMCRA"), 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, 2012 and 2011, we had approximately $76.0 million and $70.6 million in surety bonds outstanding to secure the performance of our reclamation obligations.

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Discounting resulted in reducing the accrual for asset retirement obligations by $70.7 million and $71.3 million at December 31, 2012 and 2011, respectively. Estimated payments of asset retirement obligations as of December 31, 2012 are as follows (in thousands):

Year Ending December 31,	
2013	$ 3,192
2014	2,168
2015	1,987
2016	23,762
2017	1,107
Thereafter	123,360
Aggregate undiscounted asset retirement obligations	155,576
Effect of discounting	(70,740)
Total asset retirement obligations	84,836
Less: current portion	(3,192)
Asset retirement obligations	$ 81,644

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

	Year ended December 31,	
	2012	**2011**
Beginning balance	$ 72,342	$ 58,227
Accretion expense	2,853	2,546
Payments	(2,842)	(1,920)
Allocation of liability associated with acquisition, mine development and change in assumptions	12,483	13,489
Ending balance	$ 84,836	$ 72,342

For the year ended December 31, 2012, the allocation of liability associated with acquisition, mine development and change in assumptions is a net increase of $12.5 million which was primarily attributable to the liability associated with the Onton mine acquisition (see Note 4) and increased refuse site reclamation disturbances with new mine development work at Tunnel Ridge and Gibson South, 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 and fluctuations in projected mine life estimates over all locations. These increases were offset in part by reductions for completed reclamation work at certain inactive locations.

For the year ended December 31, 2011, the allocation of liability associated with acquisition, mine development and change in assumptions is a net increase of $13.5 million which was primarily attributable to increased refuse site reclamation disturbances at our Mettiki, River View, MC Mining, Pontiki and Hopkins County Coal operations and new mine development work at Tunnel Ridge, 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 and fluctuations in projected mine life estimates. These increases were offset in part by reductions in the estimated impoundment cover material costs at Pattiki and completed reclamation work at certain inactive locations.

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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.

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 3.78% and 4.25% at December 31, 2012 and 2011, respectively, and for workers' compensation was 3.22% and 3.75% at December 31, 2012 and 2011, respectively.

The black lung and workers' compensation expense consists of the following components for the year ended December 31, 2012, 2011 and 2010 (in thousands):

	2012	2011	2010
Black lung benefits:			
Service cost	$ 3,758	$ 3,345	$ 2,359
Interest cost	2,372	2,382	1,857
Net amortization	776	(223)	(176)
Total black lung	6,906	5,504	4,040
Workers' compensation expense	17,572	18,996	16,776
Total expense	$ 24,478	$ 24,500	$ 20,816

The following is a reconciliation of the changes in the black lung benefit obligation recognized in accumulated other comprehensive income for the years ended December 31, 2012 and 2011 (in thousands);

	2012	2011
Net actuarial gain (loss)	$ 2,156	$ (4,570)
Reversal of amortization item:		
Net actuarial (gain) loss	776	(223)
Total recognized in accumulated other comprehensive income (loss)	$ 2,932	$ (4,793)

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The following is a reconciliation of the changes in workers' compensation liability (including current and long-term liability balances) at December 31, 2012 and 2011 (in thousands):

	2012	2011
Beginning balance	$ 73,201	$ 67,687
Accruals	24,812	22,254
Payments	(10,477)	