ALLIANCE RESOURCE PARTNERS LP
Form 10-K
February 28, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2011

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE TRANSITION PERIOD FROM TO

COMMISSION FILE NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE	**73-1564280**
(STATE OR OTHER JURISDICTION OF	**(IRS EMPLOYER**

INCORPORATION OR ORGANIZATION) **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. x Yes ¨ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the

Act. ¨ Yes x No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 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). x Yes ¨ No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule

12b-2 of the Exchange Act. (check one)

Large Accelerated Filer x	Accelerated Filer ¨
Non-Accelerated Filer ¨	Smaller Reporting Company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange

Act). ¨ Yes x No

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $1,595,566,038 as of June 30, 2011, the last business day of the registrant s most recently completed second fiscal quarter, based on the reported closing price of the common units as reported on the NASDAQ Stock Market, LLC on such date.

As of February 28, 2012, 36,874,949 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None

Table of Contents

TABLE OF CONTENTS

Table of Contents

FORWARD-LOOKING STATEMENTS

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

- changes in competition in coal markets and our ability to respond to such changes;
- changes in coal prices, which could affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;
- the impact of health care legislation;
- 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 due to labor and transportation costs and disruptions, equipment availability, governmental regulations, including those related to carbon dioxide emissions, and other factors;

legislation, regulatory and court decisions and interpretations thereof, including issues related to air and water quality and miner health and safety;

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;

greater than expected environmental regulation, costs and liabilities;

a variety of operational, geologic, permitting, labor and weather-related 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 alternative sources of energy, 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 credits;

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

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

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

Table of Contents

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 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.

Table of Contents

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, 2011, we had approximately 911.4 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 10. White Oak Transactions. In 2011, we produced 30.8 million tons of coal and sold 31.9 million tons of coal, of which 8.1% was low-sulfur coal, 19.2% was medium-sulfur coal and 72.7% was high-sulfur coal. In 2011, we sold 90.6% of our total tons to electric utilities, of which 98.8% was sold to utility plants with installed pollution control devices. These devices, also known as scrubbers, eliminate substantially all emissions of sulfur dioxide. We classify low-sulfur coal as coal with a sulfur content of less than 1%, medium-sulfur coal as coal with a sulfur content between 1% and 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

We operate ten underground mining complexes in Illinois, Indiana, Kentucky, Maryland, and West Virginia, including the new Tunnel Ridge mine in 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 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, 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 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.

Table of Contents

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, 2011:

(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. Certain provisions of the transfer restrictions agreement may cause the parties to it to comprise a group under Rule 13d-5(b) of the Exchange Act.

Our internet address is *http://www.arlp.com*, and we make available free of charge on our website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K 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.

Table of Contents

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934, as amended (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 and Complexes	**2011**	**2010**	**2009**	**2008**	**2007**
	(tons in millions)				
Illinois Basin:					
Dotiki, Warrior, Pattiki, Hopkins, River View and Gibson complexes	25.5	23.7	20.7	20.3	17.9
Central Appalachian:					
Pontiki and MC Mining complexes	2.5	2.3	2.6	3.2	3.2
Northern Appalachian:					
Mettiki and Tunnel Ridge complexes	2.8	2.9	2.5	2.9	3.2
Total	30.8	28.9	25.8	26.4	24.3

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, 2012, we had 2,598 employees, and we operate six 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 is constructing a new preparation plant that is expected to be operational in early 2012 and will have 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 sale to customers capable of receiving barge deliveries.

Warrior Complex. Our subsidiary, Warrior Coal, LLC (Warrior), operates an underground mining complex located near the city of Madisonville in Hopkins County, Kentucky. The Warrior complex was opened in 1985, and we acquired it in February 2003. Warrior utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Warrior completed construction of a new preparation plant in the first quarter of 2009, which has throughput capacity of 1,200 tons of raw coal per hour. Warrior s production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for sale to customers capable of receiving barge deliveries. In 2011, Warrior acquired the Richland No. 9 Mine (Richland), a one-unit mine located near the Warrior complex. Production from Richland, which will be processed through Warrior s preparation plant, will begin in January 2012 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 sale to customers capable of receiving barge deliveries. A failure of the vertical hoist conveyor system temporarily halted production from the Pattiki mine for a period of approximately two months beginning May 13, 2010 and resulted in limited production from the mine until full production was resumed on January 3, 2011.

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 sale to customers capable of receiving barge deliveries.

Gibson Complex. Our subsidiary, Gibson County Coal, LLC (Gibson County Coal), operates the Gibson North mine and our subsidiary Gibson County Coal (South), LLC (Gibson South) is constructing the Gibson South mine. The Gibson North mine is, and the Gibson South mine will be, an underground mine. Both are 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 has throughput capacity of 700 tons of raw coal per hour. Construction of the Gibson South mine, which will utilize continuous mining units employing room-and-pillar mining techniques to produce medium-sulfur coal, began in 2011. The Gibson South mine s preparation plant will have throughput capacity of 1,800 tons of raw coal per hour. We expect Gibson South to begin production in the third quarter of 2014 and to reach annual production capacity of approximately 3.0 to 3.5 million tons in 2015.

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 sale to customers capable of receiving barge deliveries. Production from Gibson South mine, when completed, will be shipped by truck on U.S. and state highways directly to customers or to the Gibson North rail loadout facility. Capital expenditures required to develop the Gibson South mine are estimated to be in the range of approximately $180.0 million to $190.0 million, of which approximately $6.4 million has been incurred as of December 31, 2011. 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 construction of an underground mining complex to access the reserves, which utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Production began in August 2009 and expanded to eight continuous mining units in 2010. A ninth continuous mining unit was added in 2011. 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 Reserves. We control, through our subsidiaries, Alliance Resource Properties, LLC (Alliance Resource Properties) and ARP Sebree, LLC, undeveloped reserves in Webster County, Kentucky, which we refer to as the Sebree Reserves . We are in the process of permitting the Sebree property for future development by our subsidiary Sebree Mining, LLC (Sebree).

Central Appalachian Operations

Our Central Appalachian mining operations are located in eastern Kentucky. As of February 1, 2012, we had 473 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-sulfur coal. The preparation plant has throughput capacity of 900 tons of raw coal per hour. Coal produced in 2011 remained low sulfur, but does not meet 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 NS railroad directly to customers or to various transloading facilities on the Ohio River for sale to customers capable of receiving barge deliveries, or by truck via U.S. and state highways directly to customers or to various docks on the Big Sandy River for shipment to customers capable of receiving barge deliveries. In 2009, we idled one of the four Pontiki production units due to weak coal market conditions and that unit remained idle until resuming production in the second quarter of 2011. During the fourth quarter of 2011, the entire Pontiki mine was idled for approximately 24 consecutive days due to a dispute with federal regulators. As part of the resolution of this dispute, we were required to idle one production unit and the Pontiki mine now operates with only three production units.

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 leases 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 ten million saleable tons of coal, to which all mining will transition in 2012. 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 2011 met or exceeded the compliance requirements of Phase II of the 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 sale to customers capable of receiving barge deliveries, or by truck via U.S. and state highways directly to customers or to various docks on the Big Sandy River for shipment to customers capable of receiving barge deliveries.

Northern Appalachian Operations

Our Northern Appalachian mining operations are located in Maryland and West Virginia. As of February 1, 2012, we had 519 employees, and we operate two mining complexes in Northern Appalachia. We also control undeveloped reserves in West Virginia and Pennsylvania.

Mettiki (MD) Operation. Our subsidiary, Mettiki Coal, LLC (Mettiki (MD)), previously operated an underground longwall mine located near the city of Oakland in Garrett County, Maryland. Underground longwall mining operations ceased at this mine in October 2006 upon the exhaustion of the economically mineable reserves, and the longwall mining equipment was moved from the Mettiki (MD) operation to the operation of our subsidiary, Mettiki Coal (WV), LLC (Mettiki (WV)) (discussed below). Medium-sulfur coal produced from two small-scale third-party mining operations (a surface strip mine and an underground mine) on properties controlled by Mettiki (MD) and another of our subsidiaries, Backbone Mountain, LLC, supplements the Mettiki (WV) production, providing blending optimization and allowing the operation to take advantage of market opportunities as they arise. Production from the surface strip mine was exhausted during 2011 and the mine is in reclamation.

Our Mettiki (MD) preparation plant has throughput capacity of 1,350 tons of raw coal per hour. A portion of the Mettiki (WV) production is transported to this preparation plant for processing and then trucked to a blending facility at the Virginia Electric and Power Company (VEPCO) Mt. Storm Power Station. The preparation plant also is served by the CSX railroad, which provides the opportunity to ship into the domestic and export metallurgical coal markets.

Mettiki (WV) Operation. In July 2005, Mettiki (WV) began continuous miner development of the Mountain View mine located in Tucker County, West Virginia. Upon completion of mining at the Mettiki (MD) longwall operation, the longwall mining equipment was moved to the Mountain View mine and put into operation in November 2006. The Mountain View mine produces medium-sulfur coal which is transported by truck either to the Mettiki (MD) preparation plant (which is served by the CSX railroad) or to the coal blending facility at the VEPCO Mt. Storm Power Station.

Tunnel Ridge Complex. Our subsidiary, Tunnel Ridge, LLC (Tunnel Ridge), controls, through a coal lease agreement with our special general partner, approximately 100.3 million tons of proven and probable high-sulfur coal in the Pittsburgh No. 8 coal seam in West Virginia and Pennsylvania. In 2008, Tunnel Ridge began construction of the mining complex, which is an underground, longwall mine, and development mining began in 2010. During 2011, we had incidental production of approximately 268,000 tons as development mining continued. We expect to begin longwall mining operations at Tunnel Ridge in the second quarter of 2012, with annual production capacity of approximately 6.5 to 6.8 million tons. Coal produced from the Tunnel Ridge mine is transported by conveyor belt to a barge loading facility on the Ohio River. Total capital expenditures required for development of Tunnel Ridge are estimated to be in the range of approximately $290.0 million to $300.0 million, of which approximately $260.0 million has been incurred as of December 31, 2011. 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.)

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). We expect to develop these reserves as an underground mining complex using continuous mining units employing room-and-pillar techniques that will have an annual production capacity of approximately 2.5 to 3.0 million tons.

Other Operations

Mt. Vernon Transfer Terminal, LLC

Our subsidiary, Mt. Vernon, leases land and operates a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Coal is delivered to Mt. Vernon by both rail and truck. The terminal has a capacity of 8.0 million tons per year with existing ground storage of approximately 60,000 to 70,000 tons. During 2011, the terminal loaded approximately 2.3 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 2011, we sold approximately 539,000 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, which 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 sale to customers capable of receiving barge deliveries. For more information about the White Oak transactions, please read Item 8. Financial Statements and Supplementary Data Note 10. White Oak Transactions.

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 2011, 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 2011, revenues from these services have represented less than one percent of our total revenues. 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 2011, our financial results were not significantly impacted by MAC s business.

Table of Contents

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 20. 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 2011, approximately 92.2% and 90.5% 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 2012 to 2016. As of January 28, 2012, our nominal commitment under long-term contracts was approximately 33.8 million tons in 2012, 33.5 million tons in 2013, 27.2 million tons in 2014 and 19.8 million tons in 2015. The commitment of coal under contract is an approximate number because, in some instances, our contracts contain provisions that could cause the nominal commitment to increase or decrease by as much as 20%. 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 2011 were Louisville Gas and Electric Company and Tennessee Valley Authority. During 2011, we derived approximately 26.1% 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 19. Concentration of Credit Risk and Major Customers.

Table of Contents

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., International Coal Group, Inc., James River Coal Company, Murray Energy, Inc., Patriot Coal Corporation, 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 metallurgical coal market. 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 4.0% 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 60.7% of our 2011 sales volume was initially shipped from the mines by rail, 14.3% was shipped from the mines by truck and 25.0% was shipped from the mines by barge. In 2011, the largest volume transporter of our coal shipments was the CSX, railroad which moved approximately 37.5% 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.

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.

Table of Contents

We are committed to conducting mining operations in compliance with applicable federal, state and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, particularly the regulatory system of the Mine Safety and Health Administration (MSHA) where citations can be issued without regard to fault and many of the standards include subjective elements, it is not reasonable to expect any coal mining company to comply with all requirements at all times. 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 we later determine these accruals to be 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.

Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since 1969 when 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 also 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 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.

Table of Contents

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.

In 2006, the Federal Mine Improvement and New Emergency Response Act of 2006 (MINER Act) was enacted. The 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) performs an independent assessment of MSHA s data and methodology used in creating the rule. Despite this enactment, MSHA has announced that it intends to promulgate the final rule in April 2012.

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 in January 2012, West Virginia began consideration of additional mine safety legislation. Other states may pass similar legislation in the future. Additionally, new federal mine safety legislation has been introduced for consideration by the 112th Congress.

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.

Table of Contents

Black Lung Benefits Act

The Federal Black Lung Benefits Act (BLBA) requires businesses that conduct current mining operations to make payments of black lung benefits to 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.

The Patient Protection and Affordable Care Act (PPACA), signed into law on March 23, 2010, includes provisions, retroactive to 2005, which would (1) provide an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim, without requiring proof that the death was due to pneumoconiosis, or black lung, and (2) establish 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.

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 Surface Mining Control and Reclamation Act.

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.

Table of Contents

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 $0.315 per ton and $0.135 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 15. 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 that have been issued since the time of the violations revoked or, in the case of civil penalties and reclamation fees, since the time those amounts 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. 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. In addition, Congress has proposed, and may in the future propose, legislation to restrict the placement of mining material in streams. The requirements of the revised SBZ Rule or future legislation, 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, 2011, we had approximately $70.6 million in surety bonds outstanding to secure the performance of our reclamation obligations.

Table of Contents

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 2011, we sold 90.6% of our total tons to electric utilities, of which 98.8% was sold to utility plants with installed pollution control devices. These requirements would not be supplanted by the Cross-State Air Pollution Rule (CSAPR), discussed below, were it to take effect.

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 Clean Air Interstate Rule (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 CSAPR, a replacement rule for CAIR, which requires 28 states in the Midwest and eastern seaboard to reduce power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. Under CSAPR, the first phase of the nitrogen oxide and sulfur dioxide emissions reductions would commence in 2012 with further reductions effective in 2014. However, on December 30, 2011, the D.C. Circuit Court of Appeals stayed the implementation of CSAPR pending resolution of judicial challenges to the rules and ordered the EPA to continue enforcing CAIR until the pending legal challenges have been resolved. We are unable to predict whether CSAPR program will be upheld but for states to meet their requirements under CSAPR as currently written, a number of coal-fired electric generating units will likely be prematurely retired, rather than retrofitted with emission control technologies. These closures are likely to reduce the demand for coal.

Table of Contents

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). The EPA also issued a proposed rule requiring Utility Boiler Maximum Achievable Control Technology standards (MACT) for power plants, which would regulate the emission of other 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. MATS and MACT impose stricter limitations on mercury emissions from power plants than the vacated CAMR. In addition, certain states have adopted or proposed mercury control regulations that are more stringent than the federal requirements. The Obama Administration has also indicated a desire to negotiate an international treaty to reduce mercury pollution. More stringent regulation of mercury or other emissions by the EPA, state regulators, Congress, or pursuant to an international treaty may decrease the future demand for coal, but we are unable to predict the magnitude of any such impact with any reasonable degree of certainty.

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 state implementation plans (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. Notwithstanding the decision, we expect that additional emissions control requirements may be imposed on new and expanded coal-fired power plants and industrial boilers in the years ahead. 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. On December 23, 2011, the EPA administrator signed a final rule under which the emission caps imposed under CSAPR for a given state would supplant the obligations of that state with regard to visibility protection. That rule has not yet been published, and EPA s plans about publishing this rule in light of the stay of CSAPR have yet to be announced. The regional haze program 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.

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.

Table of Contents

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. In addition, the U.S. is actively participating in international discussions that are currently underway to develop a treaty to replace the Kyoto Protocol after its expiration. 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). Several groups have filed petitions asking the EPA to reconsider the Endangerment Finding. Further, several groups have filed petitions asking the U.S. Court of Appeals for the District of Columbia Circuit to review the legality of the EPA s 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. Sources that are smaller, those with emissions of less than 50,000 tons of greenhouse gases per year, will not be regulated until at least April 30, 2016, and may be permanently excluded from the permitting requirements. In December 2010, the EPA issued its plan to update pollution standards for fossil fuel power plants and petroleum refineries. The EPA had stated that it intended to propose standards for power plants in July 2011 and for refineries in December 2011 and issue final standards in May 2012 and November 2012, respectively. As of early December 2011, the EPA reportedly has prepared a proposal to regulate GHG emissions from only new plants, not existing ones, but that proposal is pending review at the U.S. Office of Management and Budget and is not yet public. The EPA anticipates that a notice of proposed rulemaking will be published in the Federal Register in early 2012. The EPA s failure to propose rules by the required date will delay final action, as well.

Lawsuits challenging the tailoring rule have already been brought, and as a result of such challenges, the rule may be modified or vacated in whole or in part. 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 report to the EPA data regarding such emissions. This rule 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 this rule, including ours, were required to begin monitoring greenhouse gas emissions on January 1, 2011 and must begin reporting to the EPA on September 28, 2012 for monitoring during 2011 and the first six months of 2012.

Table of Contents

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 30 states have currently adopted mandatory renewable portfolio standards, which 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. However, general permits under Nationwide Permit 21 (NWP 21) adopted by the Corps of Engineers under its authority in Section 404 of the CWA are no longer available because the Corps of Engineers suspended the use of NWP 21 in the Appalachian states on June 12, 2010. 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, interim final guidance issued by the EPA on April 1, 2010, encourages EPA Regions 3, 4 and 5 to (1) 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 (2) exercise a greater degree of oversight with regard to state issued general Section 404 permits.

In addition, on April 1, 2010, the EPA issued a guidance document on water quality requirements for coal mines in Appalachia. This guidance follows up on a June 11, 2009 announcement by the EPA that it would undertake a new level of enhanced review of 79 coal mining-related applications for Section 404 permits (Enhanced Coordination Procedures). On October 6, 2011, in a lawsuit challenging the legality of this action by the EPA, the U.S. District Court for the District of Columbia granted partial summary judgment rejecting the EPA s Enhanced Coordination Procedures on several legal grounds including the lack of authority under the CWA and the failure to provide appropriate notice and comment pursuant to the Administrative Procedures Act. As a result of this decision, the Corps of Engineers and the EPA Regions in Appalachia have ceased using the Enhanced Coordination Procedures. Whether this decision reduces the back up and delays in the Section 404 permit application procedures remains to be seen.

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 previously issued permits in connection with the 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. More frequent use of the EPA s Section 404 veto power as well as the increased risk of application of this power to previously permitted projects 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.

These various initiatives by the EPA have extended the time required to obtain some permits required for coal mining and have caused the costs of obtaining and complying with those permits to increase substantially. It is possible that some of our projects may not be able to obtain these permits or may experience delays in securing, utilizing or renewing permits because of the manner in which these rules are being interpreted and applied.

Total Maximum Daily Load (TMDL) regulations under the CWA establish a process to calculate the maximum amount of a pollutant that a 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. This process applies to those waters that states have designated as impaired (i.e., as not meeting present water quality standards). Industrial dischargers, including coal mines, will be required to meet new TMDL allocations for these stream segments. The adoption of new TMDL-related allocations for 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. If CCB is not classified as hazardous waste, it is not anticipated that regulation of CCB will have any material effect on the amount of coal used by electricity generators. However, 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, 2012, we employed 3,832 full-time employees, including 3,590 employees involved in active mining operations, 92 employees in other operations, and 150 corporate employees. Our work force is entirely union-free. We believe that relations with our employees are generally good.

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into an amended and restated administrative services agreement (Administrative Services Agreement) with our managing general partner, the Intermediate Partnership, AGP, AHGP and Alliance Resource Holdings, II (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, 2011 of $0.4 million from AHGP and $0.2 million from ARH II. Please read Item 13 Certain Relationships and Related Transactions, and Director Independence *Administrative Services*.

Table of Contents

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.

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, 2011, 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 over our business activities, including our cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of AHGP, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness.

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

Our unitholders do not elect our managing general partner or vote on our managing general partner s officers or directors. As of December 31, 2011, AHGP owned approximately 42.3% 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, 2011, AHGP held approximately 42.3% 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 17. Related-Party Transactions.

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

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

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

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

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

Table of Contents

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.

Table of Contents

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.
- 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 recovered in 2010 from 2009 levels, the continuation of the recovery, especially for industries in the U.S. and Europe, is uncertain. During recent years, 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.

Table of Contents

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.

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.

Table of Contents

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.

A substantial decrease in the amount of coal we sell pursuant to long-term contracts would reduce the certainty of the price and amounts of coal sold and subject our revenue stream to increased volatility. If that were to happen, changes in spot market coal prices would have a greater impact on our results, and any decreases in the spot market price for coal could adversely affect our profitability and cash flow. In 2011, we sold approximately 92.2% 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.

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. 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*.

Table of Contents

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 its findings 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 reportedly prepared a proposal to regulate greenhouse gas emissions from new power plants but not currently existing power plants. However, this proposal is not finalized and could be modified to require regulation of all fossil fuel power plants. In addition, it is possible more federal legislation 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 recent 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.

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 2011, we derived approximately 26.1% of our total revenues from two customers and at least 10.0% of our 2011 total revenues from each of the two. If we were to lose either of these customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to decrease the amounts of coal purchased or the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition and results of operations.

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

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

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

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

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

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

- 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; and
- fluctuations in transportation costs and the availability or reliability of transportation.

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 September 2011, we completed our annual property and casualty insurance renewal with various insurance coverages effective October 1, 2011. 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.

[Table of Contents](#)

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. In addition, the National Labor Relations Board has adopted new rules that would expedite unionization elections, which could make staying union-free more difficult. 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 quality standards, water pollution, 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*.

Table of Contents

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 recently 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. 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 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.

Despite recent improvements, financial markets remain volatile and persistent weaknesses continue to plague global economies. These conditions continue to negatively impact the debt and equity capital markets and could adversely impact 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.

Table of Contents

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

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

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

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

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

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

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

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

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

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

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

Our coal mining operations are affected by commodity prices. We use significant amounts of steel, petroleum products and other raw materials in various pieces of mining equipment, supplies and materials, including the roof bolts 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, 2011, our total long-term indebtedness outstanding was $686.0 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.

33

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 18. 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 federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service (IRS) on this matter.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a publicly-traded partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we are so treated, a change in our business could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

In addition, current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If we were subject to federal income tax as a corporation or 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.

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 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.

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

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

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

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

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

If you sell your units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those units. Because distributions in excess of your allocable share of our net taxable income 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.

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. Recently, however, the U.S. Treasury Department 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 loaned 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 a unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of the loaned units, he 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 to the short seller, 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 loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

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

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

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

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

Table of Contents

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 our partnership for federal income tax purposes.

We will be considered to have technically terminated our 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 us filing two tax returns for one fiscal year and could result in a 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 his taxable income for the year of termination. A termination does 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 tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has recently announced a relief procedure whereby the IRS may allow a publicly-traded partnership that has technically terminated to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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

In addition to 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 federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

Table of Contents

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, 2011, we had approximately 911.4 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, 2011, about our mining operations:

Operations	Mine Type	Heat Content (BTUs per pound)	Proven and Probable Reserves							
			Pounds $S0_2$ per MMBTU				Reserve Assignment		Reserve Control	
			<1.2	1.2-2.5	>2.5	Total	Assigned	Unassigned	Owned	Leased
			(tons in millions)							
Illinois Basin Operations										
Dotiki (KY)	Underground	12,200			51.9	51.9	51.9		20.3	31.6
Warrior (KY)	Underground	12,600			119.5	119.5	68.1	51.4	32.3	87.2
Hopkins (KY)	Underground	12,200			37.8	37.8	22.7	15.1	6.9	30.9
	/ Surface	11,500			7.8	7.8	7.8		7.8	
River View (KY)	Underground	11,600			128.9	128.9	128.9		13.4	115.5
Sebree (KY)	Underground	11,400			25.2	25.2		25.2		25.2
Pattiki (IL)	Underground	11,500			59.2	59.2	59.2		0.1	59.1
Gibson (North) (IN)	Underground	11,500		15.2	3.9	19.1	19.1		0.1	19.0
Gibson (South) (IN)	Underground	11,500		19.6	41.4	61.0	61.0		17.4	43.6
Region Total				34.8	475.6	510.4	418.7	91.7	98.3	412.1
Central Appalachian Operations										
Pontiki (KY)	Underground	12,900		7.1		7.1	7.1			7.1
MC Mining (KY)	Underground	12,600	12.6	0.5	1.5	14.6	14.6		1.6	13.0
Region Total			12.6	7.6	1.5	21.7	21.7		1.6	20.1
Northern Appalachian Operations										
Mettiki (MD)	Underground	13,200		2.1	5.6	7.7	7.7			7.7
Mountain View (WV)	Underground	13,200		4.6	5.1	9.7	9.7			9.7
Tunnel Ridge (PA/WV)	Underground	12,700			100.3	100.3	100.3			100.3
Penn Ridge (PA)	Underground	12,500			56.7	56.7	56.7			56.7
Region Total				6.7	167.7	174.4	174.4			174.4
Total			12.6	49.1	644.8	706.5	614.8	91.7	99.9	606.6
% of Total			1.8%	6.9%	91.3%	100.0%	87.0%	13.0%	14.1%	85.9%

The following table sets forth information related to reserves leased to White Oak at December 31, 2011:

Operations	Mine Type	Heat Content (BTUs per pound)	Proven and Probable Reserves Pounds SO_2 per MMBTU <1.2	1.2-2.5	>2.5	Total	Reserve Assignment Assigned	Unassigned	Reserve Control Owned	Leased
			(tons in millions)							
Illinois Basin Operations										
White Oak (IL)	Underground	11,700			204.9	204.9	204.9		11.6	193.3

38

Table of Contents

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 12.6 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.

Tons produced by White Oak from reserves we lease to them are not included in the amounts of produced tons that we report, as shown in the below table. There were no tons produced from reserves leased to White Oak for the year ended December 31, 2011.

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 6.4 million tons, Pattiki 3.5 million tons, Hopkins County Coal 2.4 million tons, River View 22.0 million tons, Sebree 0.3 million tons, Gibson (North) 2.4 million tons, Gibson (South) 5.6 million tons, Warrior 8.5 million tons, Mettiki 2.9 million tons, Tunnel Ridge 3.0 million tons, Penn Ridge 3.4 million tons, Pontiki 8.5 million tons, and 64.3 million tons of coal located near the River View complex, for total non-reserve coal deposits of 133.2 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.

Table of Contents

Mining Operations

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

$000,000	$000,000	$000,000	$000,000	$000,000	$000,000	$000,000
			Tons Produced		Transportation	Equipment
Operations	**Location**	**2011**	**2010**	**2009**		
			(in millions)			
Illinois Basin Operations						
Dotiki	Kentucky	3.6	3.9	4.2	CSX, PAL, truck, barge	CM
Warrior	Kentucky	5.4	5.8	6.2	CSX, PAL, truck, barge	CM
Hopkins	Kentucky	3.3	3.3	4.0	CSX, PAL, truck, barge	CM, DL
River View	Kentucky	7.6	5.9	0.5	Barge	CM
Pattiki	Illinois	2.2	1.7	2.5	CSX, EVW, barge	CM
Gibson (North)	Indiana	3.4	3.1	3.3	CSX, NS, truck, barge	CM
Region Total		25.5	23.7	20.7		
Central Appalachian Operations						
Pontiki	Kentucky	1.0	0.9	1.1	NS, truck, barge	CM
MC Mining	Kentucky	1.5	1.4	1.5	CSX, truck, barge	CM
Region Total		2.5	2.3	2.6		
Northern Appalachian Operations						
Mettiki	Maryland	0.2	0.4	0.3	Truck, CSX	CM, CS
Mountain View	West Virginia	2.3	2.4	2.2	Truck, CSX	LW, CM
Tunnel Ridge	West Virginia	0.3	0.1		Barge	LW, CM
Region Total		2.8	2.9	2.5		
TOTAL		30.8	28.9	25.8		

CSX	CSX Railroad
NS	Norfolk Southern Railroad
PAL	Paducah & Louisville Railroad
CM	Continuous Miner
LW	Longwall
EVW	Evansville Western Railroad
DL	Dragline with Stripping Shovel, Front End Loaders and Dozers
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 18. 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.

Table of Contents

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, 2012, the closing market price for the common units was $72.34 per unit. As of February 15, 2011, there were 36,874,949 common units outstanding. There were approximately 39,055 record holders and beneficial owners (held in street name) of common units at December 31, 2011.

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 2010	$45.72	$37.51	$0.790 (paid May 14, 2010)
2nd Quarter 2010	$52.45	$37.96	$0.810 (paid August 13, 2010)
3rd Quarter 2010	$60.95	$43.00	$0.830 (paid November 12, 2010)
4th Quarter 2010	$66.11	$55.99	$0.860 (paid February 14, 2011)
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)

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.

Table of Contents

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, 2011, 2010, 2009, 2008 and 2007.

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

	Year Ended December 31,				
	2011	2010	2009	2008	2007
Statements of Income					
Sales and operating revenues:					
Coal sales	$ 1,786.1	$ 1,551.5	$ 1,163.9	$ 1,093.1	$ 960.3
Transportation revenues	31.9	33.6	45.7	44.7	37.7
Other sales and operating revenues	25.6	24.9	21.4	18.7	35.3
Total revenues	1,843.6	1,610.0	1,231.0	1,156.5	1,033.3
Expenses:					
Operating expenses (excluding depreciation, depletion and amortization)	1,131.8	1,009.9	797.6	801.9	685.1
Transportation expenses	31.9	33.6	45.7	44.7	37.7
Outside coal purchases	54.3	17.1	7.5	23.8	22.0
General and administrative	52.3	50.8	41.1	37.2	34.4
Depreciation, depletion and amortization	160.3	146.9	117.5	105.3	85.3
Gain from sale of coal reserves				(5.2)	
Net gain from insurance settlement and other (1)				(2.8)	(11.5)
Total operating expenses	1,430.6	1,258.3	1,009.4	1,004.9	853.0
Income from operations	413.0	351.7	221.6	151.6	180.3
Interest expense (net of interest capitalized)	(22.0)	(30.1)	(30.8)	(22.1)	(11.7)
Interest income	0.4	0.2	1.0	3.7	1.7
Equity in loss of affiliates, net	(3.4)				
Other income	1.0	0.9	1.3	0.9	1.4
Income before income taxes	389.0	322.7	193.1	134.1	171.7
Income tax expense (benefit)	(0.4)	1.7	0.7	(0.5)	1.6
Net income	389.4	321.0	192.4	134.6	170.1
Less: Net (income) loss attributable to noncontrolling interest			(0.2)	(0.4)	0.3
Net income attributable to Alliance Resource Partners, L.P. (Net Income of ARLP)	$ 389.4	$ 321.0	$ 192.2	$ 134.2	$ 170.4
General Partners interest in Net Income of ARLP	$ 86.3	$ 73.2	$ 60.7	$ 45.7	$ 31.3
Limited Partners interest in Net Income of ARLP	$ 303.1	$ 247.8	$ 131.5	$ 88.5	$ 139.1
Basic and diluted net income of ARLP per limited partner unit (2)	$ 8.13	$ 6.68	$ 3.56	$ 2.39	$ 3.78
Distributions paid per limited partner unit	$ 3.6275	$ 3.205	$ 2.95	$ 2.53	$ 2.20
	36,769,126	36,710,431	36,655,555	36,604,707	36,548,150

Weighted average number of units outstanding-basic and diluted

Balance Sheet Data:					
Working capital	$ 269.3	$ 348.7	$ 54.9	$ 239.8	$ 25.9
Total assets	1,731.5	1,501.3	1,051.4	1,030.6	701.7
Long-term obligations (3)	688.5	704.2	422.5	440.8	137.1
Total liabilities (4)	1,107.8	1,045.5	730.4	740.4	384.0
Partners capital (4)	$ 623.7	$ 455.8	$ 321.0	$ 290.2	$ 317.7
Other Operating Data:					
Tons sold	31.9	30.3	25.0	27.2	24.7
Tons produced	30.8	28.9	25.8	26.4	24.3
Revenues per ton sold (5)	$ 56.75	$ 52.04	$ 47.41	$ 40.88	$ 40.31
Cost per ton sold (6)	$ 38.79	$ 35.58	$ 33.85	$ 31.72	$ 30.02
Other Financial Data:					
Net cash provided by operating activities	$ 574.0	$ 520.6	$ 282.7	$ 261.0	$ 244.0
Net cash used in investing activities	(401.1)	(295.0)	(320.1)	(184.1)	(178.7)
Net cash provided by (used in) financing activities	(238.9)	92.7	(186.6)	166.8	(101.0)
EBITDA (7)	570.8	499.5	340.4	257.8	267.0
Maintenance capital expenditures (8)	192.7	90.5	96.1	77.7	76.3

(1) Represents the net gain from the final settlement in 2007 with our insurance underwriters for claims relating to a fire at the Dotiki mine and a fire at MC Mining (MC Mining Fire Incident), and 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.

Table of Contents

(2) Basic and diluted earnings per unit (EPU) have been restated for the years ending December 31, 2008 and 2007 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, 2011, long-term incentive plan (LTIP), Supplemental Executive Retirement Plan (SERP) and Directors compensation units of 409,970 were considered anti-dilutive. For the years ended December 31, 2010, 2009, 2008 and 2007, LTIP units of 232,042, 176,743, 165,175 and 252,061, 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 of the adoption of the FASB ASC 810-10-65 and 810-10-45-16 amendments, 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) Revenues per ton sold are based on the total of coal sales and other sales and operating revenues divided by tons sold.

(6) Cost per ton sold is based on the total of operating expenses, outside coal purchases and general and administrative expenses 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 of ARLP before income taxes, net income attributable to noncontrolling interest, interest income, interest expense 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).

Table of Contents

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 of ARLP (in thousands):

	Year Ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
Cash flows provided by operating activities	$ 573,983	$ 520,588	$ 282,741	$ 261,041	$ 244,012
Non-cash compensation expense	(6,235)	(4,051)	(3,582)	(3,931)	(3,925)
Asset retirement obligations	(2,546)	(2,579)	(2,678)	(2,827)	(2,419)
Coal inventory adjustment to market	(386)	(498)	(3,030)	(452)	(21)
Equity in loss of affiliates, net	(3,404)				
Net gain (loss) on foreign currency exchange		(274)	653		
Net gain (loss) on sale of property, plant and equipment	634	(234)	(136)	911	3,189
Gain on sale of coal reserves				5,159	
Gain from insurance recoveries for property damage					2,357
Gain from insurance settlement proceeds received in a prior period					5,088
Loss on retirement of vertical hoist conveyor system		(1,204)			
Other	(1,488)	(1,448)	(537)	(366)	(811)
Net effect of working capital changes	(10,870)	(42,402)	36,440	(19,661)	7,898
Interest expense, net	21,579	29,862	29,798	18,418	9,952
Income tax expense (benefit)	(431)	1,741	708	(480)	1,669
EBITDA	570,836	499,501	340,377	257,812	266,989
Depreciation, depletion and amortization	(160,335)	(146,881)	(117,524)	(105,278)	(85,310)
Interest expense, net	(21,579)	(29,862)	(29,798)	(18,418)	(9,952)
Income tax (expense) benefit	431	(1,741)	(708)	480	(1,669)
Net income	389,353	321,017	192,347	134,596	170,058
Net (income) loss attributable to noncontrolling interest			(190)	(420)	332
Net income of ARLP	$ 389,353	$ 321,017	$ 192,157	$ 134,176	$ 170,390

(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.

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 2011, we produced 30.8 million tons of coal and we sold 31.9 million tons. The coal we produced in 2011 was approximately 8.1% low-sulfur coal, 19.2% medium-sulfur coal and 72.7% 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 ten underground mining complexes, including the new Tunnel Ridge mine in West Virginia, and at December 31, 2011, had approximately 911.4 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 10. White Oak Transactions. We believe we control adequate reserves to implement our currently contemplated mining plans. We 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 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.

Table of Contents

As discussed in more detail in Item 1A. Risk Factors, our results of operations could be impacted by prices for fuel, steel, explosives 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.

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 as indicated in Item 2. Properties , most of our operations have access to barge facilities.

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 segments correspond to the three major coal producing regions in the eastern U.S. Coal quality, coal seam height, mining and transportation methods and regulatory issues are similar within each of these three segments. The White Oak segment includes our activities associated with the White Oak longwall Mine No. 1 development project in southern Illinois. These activities currently encompass an equity investment in White Oak, the purchase, leaseback and funding of development of the White Oak coal reserves and the construction and operation of surface facilities.

- *Illinois Basin* segment is comprised of Webster County Coal s Dotiki mining complex, Gibson mining complex, which includes the Gibson North mine and the Gibson South project, Hopkins County Coal s Elk Creek mining complex, White County Coal s Pattiki mining complex, Warrior s mining complex, River View s mining complex, which initiated operations in 2009, the Sebree property and certain properties of Alliance Resource Properties and ARP Sebree, LLC. On July 25, 2011, the Board of Directors approved development of the Gibson South mine, which is currently underway. We are in the process of permitting the Sebree property for future mine development. For more information on the permitting process, and matters that could hinder or delay the process, please read Item 1. Business Regulation and Laws *Mining Permits and Approvals*.

Central Appalachian segment is comprised of Pontiki s and MC Mining s mining complexes.

Table of Contents

Northern Appalachian segment is comprised of 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 mine and the Penn Ridge property. In May 2010, incidental production began from mine development activities at Tunnel Ridge; however, longwall production is not anticipated until the second quarter of 2012. We are in the process of permitting the Penn Ridge property for future mine development. For more information on 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 segment is comprised of Alliance WOR Properties, LLC (WOR Properties) and WOR Processing. WOR Processing includes both the surface operations at White Oak currently under construction and the equity investment in White Oak. WOR Properties owns and controls the coal reserves acquired from White Oak, leases the reserves back to White Oak and is committed to certain funding of future development of these reserves by White Oak. The White Oak reportable segment will also include loans made in the future to White Oak for the construction of certain surface facilities and financing for acquisition of mining equipment. For more information on White Oak, please read Item 8. Financial Statements and Supplementary Data Note 10. White Oak Transactions of this Annual Report on Form 10-K.

Other and Corporate segment includes marketing and administrative expenses, Matrix Group, the Mt. Vernon dock activities, coal brokerage activity, our equity investment in MAC and certain properties of Alliance Resource Properties.

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 of ARLP before net interest expense, income taxes, depreciation, depletion and amortization and net income attributable to noncontrolling interest. 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.

Table of Contents

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

Sources of Our Revenue

In 2011, approximately 90.6% of our sales tonnage was purchased by electric utilities, with the balance sold to third-party resellers and industrial consumers. In 2011, approximately 92.2% of our sales tonnage, including approximately 95.6% of our medium- and high-sulfur coal sales tonnage, was sold under long-term contracts. The balance of our sales were made in the spot market. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2011, approximately 95.0% 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.

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.

We anticipate that certain government agencies will provide additional regulations or interpretations concerning the application of the Health Care Act and reporting required thereunder. In addition, various states, and numerous organizations and individual persons, have filed actions in federal court challenging the constitutionality of PPACA with varying results. The U.S. Supreme Court has agreed to review the suits. Until these regulations or interpretations are published, we are unable to reasonably estimate the further impact of such 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.

Table of Contents

The Dodd Frank Act

On July 21, 2010, President Obama signed into law the Dodd Frank Act. The Dodd Frank Act gives regulators new resolution authority, creates a new council to monitor and address systemic risk, changes the mandate of the Federal Reserve, imposes significant new regulations on banking organizations, makes significant changes to the rules that affect the process of financing business enterprises and creates a new governmental authority, the Bureau of Consumer Financial Protection, to regulate retail financial products and services, among many other provisions.

The additional regulations imposed by the Dodd Frank Act on financial institutions may result in increased costs associated with future borrowings and decreased availability of credit. However, we are presently unable to determine the significance of any potential increase in our borrowing costs or potential liquidity constraints, if any. The Dodd Frank Act also requires public mining companies to report certain safety information regarding citations, penalties and pending legal actions as an exhibit included with each periodic report filed with the SEC and to file Current Reports on Form 8-K for certain compliance matters.

Analysis of Historical Results of Operations

2011 Compared with 2010

We reported record Net Income of ARLP 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 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.

Table of Contents

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 21. 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, Alliance Service, Inc. The income tax benefit was due to operating losses in 2011 from our Matrix Design operation.

Table of Contents

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

	Year Ended December 31, 2011	Year Ended December 31, 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%.

Table of Contents

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

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- 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	Year Ended December 31, 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.

Table of Contents

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.

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.

Table of Contents

2010 Compared with 2009

We reported Net Income of ARLP of $321.0 million in 2010 compared to $192.2 million in 2009. This increase of $128.8 million was principally due to increased tons sold and improved contract pricing resulting in an average coal sales price of $51.21 per ton sold, as compared to $46.60 per ton sold in 2009. We sold 30.3 million tons and produced 28.9 million tons in 2010 compared to 25.0 million tons sold and 25.8 million tons produced in 2009. This increase in tons sold and produced primarily reflects increased production from our River View mine and resulted in higher operating expenses during 2010, particularly impacting materials and supplies expenses, sales-related expenses and labor and labor-related expenses. Expenses were further impacted by increased depreciation, depletion and amortization.

	December 31,		December 31,	
	2010	**2009**	**2010**	**2009**
	(in thousands)		(per ton sold)	
Tons sold	30,295	24,975	N/A	N/A
Tons produced	28,860	25,838	N/A	N/A
Coal sales	$ 1,551,539	$ 1,163,871	$ 51.21	$ 46.60
Operating expenses and outside coal purchases	$ 1,027,013	$ 805,051	$ 33.90	$ 32.23

Coal sales. Coal sales increased 33.3% to $1.6 billion in 2010 from $1.2 billion in 2009. The increase of $387.6 million reflected the benefit of increased tons sold (contributing $247.9 million in coal sales) and higher average coal sales prices (contributing $139.7 million in additional coal sales). Average coal sales price increased $4.61 per ton sold in 2010 to $51.21 per ton compared to $46.60 per ton in 2009, primarily as a result of improved contract pricing across all regions.

Operating expenses. Operating expenses increased 26.6% to $1.0 billion in 2010 from $797.5 million in 2009 primarily due to record coal sales and production volumes. Increased River View production and Tunnel Ridge development combined to increase certain operating expenses $109.0 million during 2010 compared to 2009 and are generally included in the variances discussed further below. In addition to the impact of record volumes, operating expenses were impacted by various other factors, the most significant of which are discussed below:

Labor and benefit expenses per ton produced, excluding workers compensation, decreased 1.0% to $10.97 per ton in 2010 from $11.08 per ton in 2009. The decrease of $0.11 per ton was primarily attributable to lower labor cost per ton resulting from production at our River View mine, a decrease in the cost of training new employees in the Illinois Basin and lower pension plan expense, partially offset by increased mine development labor at our Tunnel Ridge mine, heightened regulatory oversight, particularly at our Central Appalachian mines, and production disruptions at our Dotiki, Gibson and Pattiki mines during 2010;

Workers compensation expenses per ton produced decreased to $0.72 per ton in 2010 from $0.96 per ton in 2009. The decrease of $0.24 per ton primarily reflected favorable reserve adjustments in the fourth quarter of 2010 related to our annual actuary analysis for claims related to prior years, partially offset by a non-cash charge that resulted from a decrease in the discount rate from 5.27% at the end of 2009 to 4.70% at the end of 2010;

Material and supplies expenses per ton produced increased 9.7% to $10.55 per ton in 2010 from $9.62 per ton in 2009. The increase of $0.93 per ton resulted from increased costs for certain products and services, primarily roof support (increase of $0.22 per ton), outside services expenses (increase of $0.19 per ton), power and fuel used in the mining process (increase of $0.17 per ton), contract labor used in the mining process (increase of $0.12 per ton) and rock dust (increase of $0.09 per ton) in addition to the cost impact resulting from heightened regulatory oversight;

Maintenance expenses per ton produced decreased 1.1% to $3.63 per ton in 2010 from $3.67 per ton in 2009. The decrease of $0.04 per ton resulted primarily from the benefit of newer equipment and increased production at our River View mining complex, partially offset by higher maintenance at our Mettiki mine reflecting increased longwall and continuous mining run days and higher maintenance costs at our Tunnel Ridge mine;

Mine administration expenses increased $14.9 million in 2010 compared to 2009, primarily due to increased legal expenses and related contingency accruals, higher third-party product sales by Matrix Design and increased regulatory costs;

Contract mining expenses increased $5.6 million in 2010 compared to 2009. The increase primarily reflects the restart of a third-party mining operation in our Northern Appalachian region during February 2010 that was previously idled in May 2009 and increased production from other existing contract mining operations in Northern Appalachia, both in response to increased demand in the export coal market;

Production taxes and royalties (which were incurred as a percentage of coal sales or based on coal volumes) increased $0.48 per produced ton sold in 2010 compared to 2009, primarily as a result of increased average coal sales prices across all regions;

Operating expenses increased due to a reduction in coal inventory of 1.0 million tons in 2010 reflecting higher coal sales, in comparison to 2009 during which coal inventory increased 1.1 million tons; and

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 Note 3. Pattiki Vertical Hoist Conveyor System Failure in 2010 of this Annual Report on Form 10-K.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, products and services provided by MAC (in 2009 only), Matrix Design and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to $24.9 million in 2010 from $21.4 million in 2009. The increase of $3.5 million was primarily attributable to increased Matrix Design product sales, partially offset by lower transloading revenues and decreased rock dust revenues reflecting the deconsolidation of MAC.

Outside coal purchases. Outside coal purchases increased to $17.1 million in 2010 from $7.5 million in 2009. The increase of $9.6 million was primarily attributable to an increase in outside coal purchases related to our Northern Appalachian region in response to improved demand in the export coal markets and increased coal brokerage activity partially offset by decreased outside coal purchases in the Central Appalachian region due to the lack of attractive sales opportunities in the coal spot markets that were available in the first quarter of 2009.

General and administrative. General and administrative expenses in 2010 increased to $50.8 million compared to $41.1 million in 2009. The increase of $9.7 million was primarily attributable to increased incentive compensation expense and retirement plan expense.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $146.9 million in 2010 compared to $117.5 million in 2009. The increase of $29.4 million was primarily attributable to additional depreciation expense associated with our River View mine in addition to continuing capital expenditures related to infrastructure improvements and efficiency projects.

Interest expense. Interest expense, net of capitalized interest, decreased to $30.1 million in 2010 from $30.8 million in 2009. The decrease of $0.7 million was principally attributable to reduced interest expense resulting from annual principal repayments made during August 2010 and 2009 of $18.0 million on our original senior notes issued in 1999, partially offset by increased interest expense for borrowings under our revolving credit facility during 2010, each of which is discussed in more detail below under Debt Obligations.

Interest income. Interest income decreased to $0.2 million in 2010 from $1.0 million in 2009. The decrease of $0.8 million resulted from reduced interest income earned on short-term investments, which were substantially liquidated throughout 2009.

Transportation revenues and expenses. Transportation revenues and expenses each decreased to $33.6 million in 2010 from $45.7 million in 2009. The decrease of $12.1 million was primarily attributable to reduced tonnage in 2010 for which we arranged the transportation compared to 2009. The cost of transportation services are passed through to our customers. Consequently, we do not realize any gain or loss on transportation revenues.

Table of Contents

Income tax expense. Income tax expense increased to $1.7 million in 2010 from $0.7 million in 2009. The increase of $1.0 million was primarily due to higher net income in 2010 from our Matrix Design operation.

Net income attributable to noncontrolling interest. The noncontrolling interest represents a 50% third-party interest in MAC. The third party s portion of MAC s net income was $0.2 million in 2009. Effective January 1, 2010, we deconsolidated MAC based on amendments to the provisions of FASB ASC 810, *Consolidation*.

Table of Contents

Segment Information. Our 2010 Segment Adjusted EBITDA increased 44.3% to $550.3 million from 2009 Segment Adjusted EBITDA of $381.5 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, 2010	2009	Increase (Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 460,592	$ 315,542	$ 145,050	46.0%
Central Appalachia	36,714	41,149	(4,435)	(10.8)%
Northern Appalachia	46,702	15,552	31,150	(1)
Other and Corporate	6,311	9,621	(3,310)	(34.4)%
Elimination		(370)	370	(1)
Total Segment Adjusted EBITDA (2)	$ 550,319	$ 381,494	$ 168,825	44.3%
Tons sold				
Illinois Basin	24,763	19,660	5,103	26.0%
Central Appalachia	2,221	2,641	(420)	(15.9)%
Northern Appalachia	3,256	2,660	596	22.4%
Other and Corporate	55	14	41	(1)
Elimination				
Total tons sold	30,295	24,975	5,320	21.3%
Coal sales				
Illinois Basin	$ 1,176,275	$ 846,940	$ 329,335	38.9%
Central Appalachia	164,834	179,369	(14,535)	(8.1)%
Northern Appalachia	207,057	136,412	70,645	51.8%
Other and Corporate	3,373	1,150	2,223	(1)
Elimination				
Total coal sales	$ 1,551,539	$ 1,163,871	$ 387,668	33.3%
Other sales and operating revenues				
Illinois Basin	$ 1,357	$ 1,151	$ 206	17.9%
Central Appalachia	199	191	8	4.2%
Northern Appalachia	3,520	3,316	204	6.2%
Other and Corporate	41,681	39,260	2,421	6.2%
Elimination	(21,815)	(22,491)	676	3.0%
Total other sales and operating revenues	$ 24,942	$ 21,427	$ 3,515	16.4%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 717,040	$ 532,549	$ 184,491	34.6%
Central Appalachia	128,318	138,412	(10,094)	(7.3)%
Northern Appalachia	163,876	124,176	39,700	32.0%
Other and Corporate	38,743	30,789	7,954	25.8%
Elimination	(21,815)	(22,122)	307	1.4%
Total Segment Adjusted EBITDA Expense (3)	$ 1,026,162	$ 803,804	$ 222,358	27.7%

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

Table of Contents

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

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- 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 and Net Income of ARLP, the most comparable GAAP financial measure (in thousands):

	$000,000,000	$000,000,000
	Year Ended December 31,	
	2010	**2009**
Segment Adjusted EBITDA	$ 550,319	$ 381,494
General and administrative	(50,818)	(41,117)
Depreciation, depletion and amortization	(146,881)	(117,524)
Interest expense, net	(29,862)	(29,798)
Income tax expense	(1,741)	(708)
Net income	321,017	192,347
Net income attributable to noncontrolling interest		(190)
Net income of ARLP	$ 321,017	$ 192,157

(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.

Table of Contents

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,	
	2010	2009
Segment Adjusted EBITDA Expense	$ 1,026,162	$ 803,804
Outside coal purchases	(17,078)	(7,524)
Other income	851	1,247
Operating expense (excluding depreciation, depletion and amortization)	$ 1,009,935	$ 797,527

Illinois Basin Segment Adjusted EBITDA increased 46.0% to $460.6 million in 2010 from $315.5 million in 2009. The increase of $145.1 million was primarily attributable to increased tons sold, which increased 26.0% to 24.8 million tons sold in 2010, as well as improved contract pricing resulting in a higher average coal sales price of $47.50 per ton during 2010 compared to $43.08 per ton in 2009. Coal sales increased 38.9% to $1.2 billion in 2010 compared to $846.9 million in 2009. The increase of $329.3 million primarily reflects increased sales from our River View mine (which commenced operations in August of 2009 and continued to expand production during 2010), increased sales from coal inventories in the region and the negative impact of weather disruptions in 2009 at our Dotiki, Warrior and Elk Creek mines, partially offset by production disruptions at our Dotiki, Gibson and Pattiki mines during 2010. Total Segment Adjusted EBITDA Expense in 2010 increased 34.6% to $717.0 million from $532.5 million in 2009, an increase of $1.87 per ton sold to $28.96 from $27.09 per ton sold, primarily as a result of certain cost increases described above under consolidated operating expenses as well as a $1.2 million loss on the retirement of certain assets related to the failure of the vertical hoist conveyor system at our Pattiki mine, the aforementioned production disruptions at our Dotiki, Gibson and Pattiki mines and increased sales from coal inventories in the region. For more information on our Pattiki mine, please read Part II. Item 8. Financial Statements Note 3. Pattiki Vertical Hoist Conveyor System Failure in 2010 of this Annual Report on Form 10-K.

Central Appalachia Segment Adjusted EBITDA decreased $4.4 million, or 10.8%, to $36.7 million in 2010, compared to $41.1 million in 2009. The decrease was primarily the result of lower sales volumes due to the impact of heightened regulatory oversight, reduced coal demand in the spot market during 2010, lower clean coal recovery due to mining conditions and the continued impact of idling one mining unit at Pontiki beginning in July 2009, partially offset by improved contract pricing in 2010 that resulted in an increase in the average coal sales price of $6.28 per ton to $74.19 per ton in 2010, as compared to $67.91 per ton in 2009. Segment Adjusted EBITDA Expense per ton sold during 2010 increased to $57.76 compared to $52.41 per ton sold, an increase of $5.35 per ton sold, reflecting certain cost increases described above under consolidated operating expenses, as well as the impact of lower coal sales volumes and decreased coal production in response to lower spot market demand and lower productivity due to Pontiki s transition from the depleted Pond Creek coal seam into the thinner Van Lear coal seam beginning in 2009. Although Segment Adjusted EBITDA Expense per ton sold increased, Segment Adjusted EBITDA Expense for 2010 decreased 7.3% to $128.3 million from $138.4 million in 2009 primarily as a result of lower coal sales offset in part by higher expenses per ton as described above.

Northern Appalachia Segment Adjusted EBITDA increased to $46.7 million in 2010, compared to $15.6 million in 2009. The increase of $31.1 million was primarily attributable to a higher average sales price of $63.60 per ton sold in 2010 compared to $51.28 per ton sold in 2009, and a 22.4% increase in tons sold to 3.3 million tons in 2010, both resulting from improved demand in the export coal markets, as well as the benefit of increased production days and additional contract miner production. Segment Adjusted EBITDA Expense for 2010 increased 32.0% to $163.9 million from $124.2 million in 2009, an increase of $3.66 on a per ton sold basis to $50.34 from $46.68 per ton sold, primarily as a result of higher coal sales volumes, higher costs associated with producing metallurgical quality coal, lower coal recoveries due to adverse geologic conditions, as well as other cost increases described above under consolidated operating expenses, including non-capitalized costs incurred related to our Tunnel Ridge mine.

Table of Contents

Other and Corporate Segment Adjusted EBITDA decreased to $6.3 million in 2010 from $9.6 million in 2009. The decrease of $3.3 million was primarily attributable to the impact of the deconsolidation of MAC effective January 1, 2010, lower EBITDA associated with Matrix Group safety equipment sales to our other subsidiaries (which are eliminated upon consolidation), a loss in 2010 compared to a gain in 2009 associated with United Kingdom (UK) currency previously held for equipment purchases from a UK supplier and lower Mt. Vernon outside transloading revenues and affiliate administrative service revenues, partially offset by higher EBITDA resulting from increased third-party safety equipment sales and services revenue at Matrix Design. Other sales and operating revenues increased 6.2% to $41.7 million for 2010 compared to $39.3 million for 2009. The increase of $2.4 million was primarily attributable to increased services revenue and sales of mine safety equipment by Matrix Group. Segment Adjusted EBITDA Expense increased 25.8% to $38.7 million for 2010, primarily due to increased expenses associated with higher services revenue and safety equipment sales by Matrix Group, higher coal brokerage expenses associated with increased brokerage coal sales offset in part by the impact of the deconsolidation of MAC mentioned above.

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.

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 revolving credit facilities. We believe that existing cash balances, future cash flows from operations, borrowings under revolving credit facilities, and cash provided from the issuance of debt or equity will be sufficient to meet our working capital requirements, anticipated capital expenditures, scheduled debt payments 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.

Table of Contents

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, 2011, we had funded $93.5 million related to these transactions and we expect to additionally fund approximately $306.5 million to $431.5 million over the next three to four years. We plan to utilize existing cash balances, future cash flows from operations, borrowings under revolving 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 10. White Oak Transactions of this Annual Report on Form 10-K.

Our current revolving credit facility matures on September 25, 2012. We are planning to access the bank markets in the near term. As part of our planning, we will evaluate our options in the debt capital markets to ensure we have sufficient liquidity and flexibility to execute our future plans. For more information on our current revolving credit facility, please see Debt Obligations below.

Cash Flows

Cash provided by operating activities was $574.0 million in 2011 compared to $520.6 million in 2010. The increase in cash provided by operating activities was principally attributable to higher net income, an increase in the change in accounts payable in 2011 compared to 2010 and a decrease in the change in accounts receivable in 2011 compared to 2010. These increases in cash provided by operating activities were partially offset by an increase in inventory during 2011 as compared to a significant decrease during 2010.

Net cash used in investing activities was $401.1 million in 2011 compared to $295.0 million in 2010. The increase in cash used for investing activities was primarily attributable to our funding of investments related to the White Oak transactions during 2011 and higher mine infrastructure and equipment expenses at the Dotiki mine as well as increased capital expenditures at other mines, partially offset by decreases in capital expenditures at River View due to the addition of mining units during 2010 as well as timing differences in accounts payable and accrued liabilities compared to 2010.

Net cash used in financing activities was $238.9 million in 2011 compared to net cash provided by financing activities of $92.7 million in 2010. The decrease in cash provided by financing activities was primarily attributable to the proceeds from the $300 million term loan completed on December 29, 2010 (see Debt Obligations) and increased distributions paid to partners in 2011.

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, 2011 (in thousands):

	$000,000,000	$000,000,000	$000,000,000	$000,000,000	$000,000,000
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-term debt	$ 704,000	$ 18,000	$ 171,000	$ 370,000	$ 145,000
Future interest obligations[1]	139,016	34,024	61,199	29,285	14,508
Operating leases	4,321	1,752	1,192	734	643
Capital leases[2]	3,728	913	1,530	1,234	51
Purchase obligations for capital projects	161,943	161,943			
Coal purchase commitments	37,541	37,541			
Reclamation obligations[3]	143,616	1,506	2,400	17,142	122,568
Workers compensation and pneumoconiosis benefit[3]	319,295	15,013	22,517	18,614	263,151
	$ 1,513,460	$ 270,692	$ 259,838	$ 437,009	$ 545,921

(1)

Interest on variable-rate, long-term debt was calculated using rates elected by us at December 31, 2011 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.

Table of Contents

We expect to contribute $5.4 million to the defined benefit pension plan (Pension Plan) during 2012.

In addition to the above described capital expenditures related to our operating activities, we currently anticipate funding to White Oak during 2012 and 2013 approximately $248.1 million and $147.4 million, respectively, for reserve acquisitions, reserve development, construction of surface facilities, equipment 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, 2011 (in thousands):

	Reclamation Obligation	Workers Compensation Obligation	Other	Total
Surety bonds	$ 70,571	$ 39,924	$ 15,196	$ 125,691
Letters of credit		29,697	12,548	42,245

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, equipment financing and the purchase additional equity in White Oak. In addition, we incurred allocated losses related to our equity investment in White Oak of $4.3 million for the year ended December 31, 2011 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 10. White Oak Transactions of this Annual Report on Form 10-K.

Capital Expenditures

Capital expenditures increased to $321.9 million in 2011 compared to $289.9 million in 2010. 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 $5.50 per ton produced. Our anticipated total capital expenditures for 2012 are estimated in a range of $400.0 to $425.0 million, excluding our White Oak commitments. In light of the significant infrastructure projects planned for 2012, estimated capital for operating necessities is expected to be approximately $7.50 per ton in 2012. Management anticipates funding 2012 capital requirements with our December 31, 2011 cash and cash equivalents of $273.5 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 September 2011, we completed our annual property and casualty insurance renewal with various insurance coverages effective October 1, 2011. 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. Our Intermediate Partnership entered into a $150.0 million revolving credit facility (ARLP Credit Facility) dated September 25, 2007, which matures September 25, 2012. The ARLP Credit Facility was decreased to $142.5 million of availability on October 6, 2010 due to a defaulting lender, as discussed below. On September 30, 2009, our Intermediate Partnership entered into Amendment No. 2 (the Credit Amendment) to the ARLP Credit Facility. The Credit Amendment increased the annual capital expenditure limits under the ARLP Credit Facility. The new limit, before carry forward considerations and exclusion of capital expenditures related to acquisitions, is $250.0 million for 2012. The amount of any annual limit in excess of actual capital expenditures for that year carries forward and is added to the annual limit of the subsequent year. As a result, the capital expenditure limit for 2012 is approximately $460.0 million.

Pursuant to the Credit Amendment, the applicable margin for London Interbank Offered Rate borrowings under the ARLP Credit Facility was increased from a range of 0.625% to 1.150% (depending on the Intermediate Partnership s leverage margin) to a range of 1.115% to 2.000%, and the annual commitment fee was increased from a range of 0.15% to 0.35% (also depending on the Intermediate Partnership s leverage margin) to a range of 0.25% to 0.50%. In addition, the Credit Amendment includes certain changes relating to a defaulting lender, including changes which clarify that the overall ARLP Credit Facility commitment would be reduced by the commitment share of a defaulting lender but also provides our Intermediate Partnership with more flexibility in replacing a defaulting lender.

At December 31, 2011, we had $11.6 million of letters of credit outstanding with $130.9 million available for borrowing under the ARLP Credit Facility. We had no borrowings outstanding under the ARLP Credit Facility as of December 31, 2011 and 2010. We utilize the ARLP Credit Facility, as appropriate, to meet working capital requirements, anticipated capital expenditures, scheduled debt payments or distribution payments. We incur an annual commitment fee of 0.375% on the undrawn portion of the ARLP Credit Facility.

The ARLP Credit Facility is underwritten by a syndicate of eleven financial institutions with no individual institution representing more than 11.9% of the $142.5 million revolving credit facility. In the event any financial institution in the ARLP Partnership s syndicate does not fund its future borrowing requests, the ARLP Partnership s borrowing available under the ARLP Credit Facility would be reduced. The obligations of the lenders under the ARLP Credit Facility are individual obligations and the failure of one or more lenders does not relieve the remaining lenders of their funding obligations.

Senior Notes. Our Intermediate Partnership has $54.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in three 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, which bear interest at 6.72% and mature on June 26, 2018 with interest payable semi-annually.

Term Loan. On December 29, 2010, our Intermediate Partnership entered into a term loan agreement (the Term Loan Agreement) with various financial institutions for a term loan (the Term Loan) in the aggregate principal amount of $300 million. The Term Loan bears interest at a variable rate plus an applicable margin which fluctuates depending upon whether we elect the Term Loan (or a portion thereof) to bear interest on the Base Rate or the Eurodollar Rate (as defined in the Term Loan Agreement). We elected the Eurodollar Rate as of December 31, 2011 which, with applicable margin, was 2.3%. Interest is payable quarterly with principal due as follows: $15 million due per quarter beginning March 31, 2013 through December 31, 2013, $18.75 million due per quarter beginning March 31, 2014 through September 30, 2015 and the balance of $108.75 million due on December 31, 2015. 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 Term Loan Agreement. Upon a change of control (as defined in the Term Loan Agreement), the unpaid principal amount of the loan, all interest thereon and all other amounts payable under the Term Loan Agreement will become due and payable.

The net proceeds of the Term Loan have been used for the general corporate, business or working capital purposes of the Intermediate Partnership and its subsidiaries. We incurred debt issuance costs of approximately $1.4 million in 2010 associated with the Term Loan Agreement, which have been deferred and are being amortized as a component of interest expense over the term of the respective notes.

The ARLP Credit Facility, Senior Notes, Series A and Series B Senior Notes (collectively, the 2008 Senior Notes) and the Term Loan Agreement (collectively, the ARLP Debt Arrangements) are guaranteed by all of the 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 the following: (i) debt to cash flow ratio of not more than 3.0 to 1.0 and (ii) cash flow to interest expense ratio of not less than 4.0 to 1.0 in both cases, during the four most recently ended fiscal quarters. The ARLP Credit Facility, Senior Notes and the 2008 Senior Notes limit our Intermediate Partnership s maximum annual capital expenditures, excluding acquisitions, as described above. The debt to cash flow ratio and cash flow to interest expense ratio were 1.2 to 1.0 and 16.1 to 1.0, for the trailing twelve months ended December 31, 2011. Actual capital expenditures were $321.9 million for the year ended December 31, 2011. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2011.

Other. In addition to the letters of credit available under the ARLP 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, 2011, 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.

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, rock dust sales (2009 only) and other handling and service fees. These non-coal sales revenues are recognized when the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; the seller s price to the buyer is fixed or determinable; and collectability is reasonably assured.

Coal Reserve Values

All of the reserves presented in this Annual Report on Form 10-K constitute proven and probable reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may vary considerably from actual results. These factors and assumptions relate to:

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

For these reasons, estimates of the recoverable quantities of coal attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. Certain account classifications within our financial statements such as depreciation, depletion, and amortization 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 $73.2 million and $67.7 million for these costs at December 31, 2011 and 2010, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2011 approximately $5.9 million, which would have a corresponding increase in operating expenses.

Table of Contents

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 $55.6 million and $45.7 million for these benefits at December 31, 2011 and 2010, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2011 by approximately $1.0 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 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 7.90% and 8.35% at December 31, 2011 and 2010. Our expected long-term rate of return used to determine our pension expense was 8.35% for the years ended December 31, 2011 and 2010. The long-term rate of return is determined by an asset allocation assumption of 60.0% invested in domestic equity securities with an expected long-term rate of return of 9.10%, 20.0% invested in international equities with an expected long-term rate of return of 5.84% and 20.0% invested in fixed income securities with an expected long-term rate of return of 6.60%. 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 (2.7)% and 10.4% for the years ended December 31, 2011 and 2010, respectively. Lowering the expected long-term rate of return assumption by 1.0% (from 8.35% to 7.35%) at December 31, 2010 would have increased our pension expense for the year ended December 31, 2011 by approximately $0.5 million; and

Our weighted average discount rate used to determine our pension liability was 4.49% and 5.56% at December 31, 2011 and 2010, respectively. Our weighted average discount rate used to determine our pension expense was 5.56% and 5.88% at December 31, 2011 and 2010, 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 5.56% to 5.06%) at December 31, 2010 would have increased our pension expense for the year ended December 31, 2011 by approximately $0.2 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. The amount of impairment is measured by the difference between the carrying value and the fair value of the asset. We have not recorded an impairment loss for any of the periods presented.

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, 2011 and 2010, capitalized mine development costs were $73.8 million and $35.3 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 $72.3 million and $58.2 million for these costs are recorded at December 31, 2011 and 2010, 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 $13.5 million and $0.8 million for the years ended December 31, 2011 and 2010, respectively. These adjustments to the liability for the year ended December 31, 2011 were 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.

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 $71.3 million and $72.8 million at December 31, 2011 and 2010. We estimate that the aggregate undiscounted cost of final mine closure is approximately $143.6 million at December 31, 2011. 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 April 2009, 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 February 28, 2012, 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 the 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 this agreement of $0.4 million, $0.3 million and $0.4 million for the years ended December 31, 2011, 2010 and 2009, respectively, from AHGP and $0.2 million, $0.2 million and $0.5 million from ARH II for the years ended December 31, 2011, 2010 and 2009, 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 our behalf, including, but not limited to, director fees and expenses, management s salaries and related benefits (including incentive compensation), and accounting, budgeting, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $0.7 million, $1.3 million and $1.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Managing General Partner Contribution

During December 2011, an affiliated entity controlled by Mr. Craft contributed $5.0 million to AHGP for the purpose of funding certain of our general and administrative expenses. Upon AHGP s receipt of this contribution, it contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary Alliance Coal. As provided under our partnership agreement, we made a special allocation to our managing general partner of certain general and administrative expenses equal to the amount of its contribution.

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 leaseback of certain reserves and surface rights, a coal handling and services agreement and a backstop equipment financing facility. For more information about the White Oak Transactions, please read Item 8. Financial Statements and Supplementary Data Note 10. White Oak Transactions of this Annual Report on Form 10-K.

SGP Land, LLC

On May 2, 2007, SGP Land, LLC (SGP Land), a subsidiary of our special general partner, entered into a time-sharing agreement with Alliance Coal, our operating subsidiary, concerning the use of aircraft owned by SGP Land. In accordance with the provisions of the time-sharing agreement as amended, we reimbursed SGP Land $1.0 million, $0.8 million and $0.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, for use of the aircraft.

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 $0.3 million during each of the years ended December 31, 2011, 2010 and 2009. As of December 31, 2011, $2.4 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, 2011, 2010 and 2009. As of December 31, 2011, $20.6 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 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, 2011, 2010 and 2009.

Table of Contents

We have a noncancelable lease arrangement with SGP for the coal preparation plant and ancillary facilities at the Gibson County Coal mining complex. 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, 2011, 2010 and 2009 were $0.8 million, $2.6 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. 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 $221.9 million and $196.9 million at December 31, 2011 and 2010. 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 15. Asset Retirement Obligations and Note 16. Accrued Workers Compensation and Pneumoconiosis Benefits.

Pension Plan

We maintain a Pension Plan, which covers eligible employees at certain of our mining operations.

Our pension expense was $2.2 million, $2.2 million and $4.6 million for the years ended December 31, 2011, 2010 and 2009. Our pension expense is based upon a number of actuarial assumptions, including an expected long-term rate of return on our Pension Plan assets of 8.35% and discount rates of 5.56% and 5.88% for the years ended December 31, 2011 and 2010, respectively. The actual return on plan assets was (2.7)% and 10.4% for the years ended December 31, 2011 and 2010, respectively. 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 expected long-term rate of return assumption is based on broad equity and bond indices. At December 31, 2011, our expected long-term rate of return assumption was 7.90% determined by the above factors and based on an asset allocation assumption of 60.0% invested in domestic equity securities, with an expected long-term rate of return of 9.10%, 20.0% invested in international equities with an expected long-term rate of return of 5.84% and 20.0% invested in fixed income securities, with an expected long-term rate of return of 6.60%. We, along with our Pension Plan investment manager and trustee and the compensation committee of the Board of Directors of our managing general partner (Compensation Committee) regularly review our actual asset allocation in accordance with our investment guidelines and periodically rebalance our investments to our targeted allocation when considered appropriate.

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. At December 31, 2011, the discount rate was determined using high quality bond yield curves adjusted to reflect the plan s estimated payout. The discount rate determined on this basis decreased from 5.56% at December 31, 2010 to 4.49% at December 31, 2011.

As of December 31, 2011, our Pension Plan was underfunded by approximately $27.5 million. We estimate that our Pension Plan expense and cash contributions will be approximately $4.2 million and $5.4 million, respectively, in 2012. Future actual pension expense and contributions will depend on future investment performance, changes in future discount rates and various other factors related to the employees participating in the Pension Plan.

Lowering the expected long-term rate of return assumption by 1.0% (from 8.35% to 7.35%) at December 31, 2010 would have increased our pension expense for the year ended December 31, 2011 by approximately $0.5 million. Lowering the discount rate assumption by 0.5% (from 5.56% to 5.06%) at December 31, 2010 would have increased our pension expense for the year ended December 31, 2011 by approximately $0.2 million.

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 December 2010, the FASB issued Accounting Standards Update (ASU) 2010-29, *Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29). ASU 2010-29 amended FASB ASC 805, *Business Combinations*, to specify that if a public entity presents comparative financial statements and a business combination has occurred during the current reporting period, then the public entity should disclose revenues and earnings of the combined entity as though the business combination that occurred during the current year had occurred at the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures under FASB ASC 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenues and earnings. The adoption of the ASU 2010-29 amendments were effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The adoption of ASU 2010-29 did not have an impact on our condensed consolidated financial statements.

New Accounting Standards Issued and Not Yet 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 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 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 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We do not anticipate the adoption of ASU 2011-04 on January 1, 2012 to 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 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 would include components of net income, and the second statement would include components of other comprehensive income (OCI). ASU 2011-05 does not change the items that must be reported in OCI. ASU 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and its provisions must 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. We do not anticipate the adoption of ASU 2011-05 on January 1, 2012 to have a material impact on our consolidated financial statements.

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

We have significant long-term coal supply agreements as evidenced by approximately 92.2% of our sales tonnage, including approximately 95.6% of our medium- and high-sulfur coal sales tonnage, being sold under long-term contracts in 2011. 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 19. Concentration of Credit Risk and Major Customers. As of January 28, 2012, our nominal commitment under long-term contracts was approximately 33.8 million tons in 2012, 33.5 million tons in 2013, 27.2 million tons in 2014 and 19.8 million tons in 2015.

We have exposure to price risk for supplies that are used directly or indirectly in the normal course of coal production such as diesel fuel, steel, explosives 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 2011, approximately 90.6% of our sales tonnage was purchased by electric utilities. Therefore, our credit risk is primarily with domestic electric power generators. Our policy is to independently evaluate each customer s creditworthiness prior to entering into transactions and to constantly monitor outstanding accounts receivable against established credit limits. When deemed appropriate by our credit management department, we will take steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps may include obtaining letters of credit or cash collateral, requiring prepayments for shipments or establishing customer trust accounts held for our benefit in the event of a failure to pay.

Exchange Rate Risk

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

Interest Rate Risk

Borrowings under the ARLP Credit Facility and Term Loan Agreement 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 no borrowings under the ARLP Credit Facility and $300.0 million outstanding under Term Loan Agreement at December 31, 2011. A one percentage point increase in the interest rates related to the Term Loan Agreement would result in an annualized increase in 2012 interest expense of $3.0 million, based on borrowing levels at December 31, 2011. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a decrease of approximately $16.9 million in the estimated fair value of these borrowings.

Table of Contents

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, 2011 and 2010. The carrying amounts and fair values of financial instruments are as follows (in thousands):

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%				

Expected Maturity Dates as of December 31, 2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**	**Fair Value December 31, 2010**
Fixed rate debt	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 205,000	$ 145,000	$ 422,000	$ 509,483
Weighted average interest rate	6.75%	6.68%	6.61%	6.52%	6.54%	6.72%		
Variable rate debt	$	$	$ 60,000	$ 75,000	$ 165,000	$	$ 300,000	$ 300,000
Weighted average interest rate (1)	2.30%	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, 2011, held constant for the remaining term of the outstanding borrowing.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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 balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2011, and the related consolidated statements of income, cash flows, and partners capital for the year then ended. Our audit also included the 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 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, 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, 2011, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the 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 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, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 28, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of the Managing

General Partner and the Partners of

Alliance Resource Partners, L.P.:

We have audited the accompanying consolidated balance sheet of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2010 and the related consolidated statements of income, cash flows, and Partners capital for each of the two years in the period ended December 31, 2010. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules 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 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, such consolidated financial statements present fairly, in all material respects, the financial position of Alliance Resource Partners, L.P. and subsidiaries as of December 31, 2010 and the results of their operations and their cash flows for each of the two years in the period 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, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte and Touche LLP

Tulsa, Oklahoma

February 28, 2011

Table of Contents

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2011 AND 2010

(In thousands, except unit data)

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 273,528	$ 339,562
Trade receivables	128,643	112,942
Other receivables	3,525	2,537
Due from affiliates	5,116	1,912
Inventories	33,837	31,548
Advance royalties	7,560	4,812
Prepaid expenses and other assets	11,945	10,024
Total current assets	464,154	503,337
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	1,974,520	1,598,130
Less accumulated depreciation, depletion and amortization	(793,200)	(648,883)
Total property, plant and equipment, net	1,181,320	949,247
OTHER ASSETS:		
Advance royalties	27,916	27,439
Equity investments in affiliates	40,118	
Other long-term assets	18,010	21,255
Total other assets	86,044	48,694
TOTAL ASSETS	$ 1,731,518	$ 1,501,278
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 96,869	$ 63,339
Due to affiliates	494	573
Accrued taxes other than income taxes	15,873	13,901
Accrued payroll and related expenses	35,876	30,773
Accrued interest	2,195	2,491
Workers compensation and pneumoconiosis benefits	9,511	8,518
Current capital lease obligation	676	295
Other current liabilities	15,326	16,715
Current maturities, long-term debt	18,000	18,000
Total current liabilities	194,820	154,605
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	686,000	704,000
Pneumoconiosis benefits	54,775	45,039

Accrued pension benefit	27,538	13,296
Workers compensation	64,520	59,796
Asset retirement obligations	70,836	56,045
Due to affiliates		1,954
Long-term capital lease obligation	2,497	165
Other liabilities	6,774	10,595
Total long-term liabilities	912,940	890,890
Total liabilities	1,107,760	1,045,495
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Limited Partners Common Unitholders 36,775,741 and 36,716,855 units outstanding, respectively	943,325	761,875
General Partners deficit	(279,107)	(287,371)
Accumulated other comprehensive loss	(40,460)	(18,721)
Total Partners Capital	623,758	455,783
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 1,731,518	$ 1,501,278

See notes to consolidated financial statements.

76

Table of Contents

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2011	2010	2009
SALES AND OPERATING REVENUES:			
Coal sales	$ 1,786,089	$ 1,551,539	$ 1,163,871
Transportation revenues	31,939	33,584	45,733
Other sales and operating revenues	25,532	24,942	21,427
Total revenues	1,843,560	1,610,065	1,231,031
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	1,131,750	1,009,935	797,527
Transportation expenses	31,939	33,584	45,733
Outside coal purchases	54,280	17,078	7,524
General and administrative	52,334	50,818	41,117
Depreciation, depletion and amortization	160,335	146,881	117,524
Total operating expenses	1,430,638	1,258,296	1,009,425
INCOME FROM OPERATIONS	412,922	351,769	221,606
Interest expense (net of interest capitalized of $14,797, $888 and $1,291, respectively)	(21,954)	(30,062)	(30,847)
Interest income	375	200	1,049
Equity in loss of affiliates, net	(3,404)		
Other income	983	851	1,247
INCOME BEFORE INCOME TAXES	388,922	322,758	193,055
INCOME TAX EXPENSE (BENEFIT)	(431)	1,741	708
NET INCOME	389,353	321,017	192,347
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST			(190)
NET INCOME ATTRIBUTABLE TO ALLIANCE RESOURCE PARTNERS, L.P. (NET INCOME OF ARLP)	$ 389,353	$ 321,017	$ 192,157
GENERAL PARTNERS INTEREST IN NET INCOME OF ARLP	$ 86,251	$ 73,172	$ 60,639
LIMITED PARTNERS INTEREST IN NET INCOME OF ARLP	$ 303,102	$ 247,845	$ 131,518
BASIC AND DILUTED NET INCOME OF ARLP PER LIMITED PARTNER UNIT	$ 8.13	$ 6.68	$ 3.56
DISTRIBUTIONS PAID PER LIMITED PARTNER UNIT	$ 3.6275	$ 3.205	$ 2.95
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING BASIC AND DILUTED	36,769,126	36,710,431	36,655,555

See notes to consolidated financial statements.

Table of Contents

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

(In thousands)

	Year Ended December 31,		
	2011	**2010**	**2009**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 389,353	$ 321,017	$ 192,347
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	160,335	146,881	117,524
Non-cash compensation expense	6,235	4,051	3,582
Asset retirement obligations	2,546	2,579	2,678
Coal inventory adjustment to market	386	498	3,030
Loss on retirement of vertical hoist conveyor system		1,204	
Equity in loss of affiliates, net	3,404		
Net (gain) loss on foreign currency transaction		274	(653)
Net (gain) loss on sale of property, plant and equipment	(634)	234	136
Other	1,488	1,448	537
Changes in operating assets and liabilities:			
Trade receivables	(15,701)	(21,780)	(3,301)
Other receivables	(1,832)	(689)	2,838
Inventories	(2,818)	31,412	(40,917)
Prepaid expenses and other assets	(1,921)	(1,223)	1,269
Advance royalties	(3,225)	(1,820)	(3,403)
Accounts payable	21,890	8,055	(6,142)
Due to (from) affiliates	1,717	1,062	(34)
Accrued taxes other than income taxes	1,972	3,124	(418)
Accrued payroll and related benefits	5,103	8,670	1,546
Pneumoconiosis benefits	4,944	3,647	2,908
Workers compensation	5,717	4,583	6,526
Other	(4,976)	7,361	2,688
Total net adjustments	184,630	199,571	90,394
Net cash provided by operating activities	573,983	520,588	282,741
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(321,920)	(289,874)	(328,162)
Changes in accounts payable and accrued liabilities	11,640	(7,480)	5,727
Proceeds from sale of property, plant and equipment	1,526	381	8
Purchases of equity investments in affiliate	(42,700)		
Purchase of marketable securities			(4,527)
Proceeds from marketable securities			4,527
Payments to affiliate for acquisition and development of coal reserves	(50,800)		
Other	1,146	1,982	2,295
Net cash used in investing activities	(401,108)	(294,991)	(320,132)
CASH FLOWS FROM FINANCING ACTIVITIES:			

Payments on long-term debt	(18,000)	(18,000)	(18,000)
Borrowings under term loan		300,000	
Borrowings under revolving credit facilities		95,000	
Payments under revolving credit facilities		(95,000)	
Payments on capital lease obligation	(812)	(324)	(351)
Payment of debt issuance costs		(1,417)	(339)
Net settlement of employee withholding taxes on vesting of Long-Term Incentive Plan	(2,324)	(1,265)	(791)
Cash contributions by General Partners	87	43	31
Distributions paid to Partners	(217,860)	(186,354)	(167,131)
Net cash (used in) provided by financing activities	(238,909)	92,683	(186,581)
EFFECT OF CURRENCY TRANSLATION ON CASH		(274)	653
NET CHANGE IN CASH AND CASH EQUIVALENTS	(66,034)	318,006	(223,319)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	339,562	21,556	244,875
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 273,528	$ 339,562	$ 21,556

See notes to consolidated financial statements, including Note 14 for supplemental cash flow information.

Table of Contents

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

(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, 2009	36,613,458	$ 604,998	$ (295,834)	$ (19,899)	$ 927	$ 290,192
Comprehensive income:						
Net income		131,518	60,639		190	192,347
Actuarially determined long-term liability adjustments				2,750		2,750
Total comprehensive income						195,097
Issuance of units to Long-Term Incentive Plan participants upon vesting	47,571	(791)				(791)
Common unit based compensation under Long-Term Incentive Plan		3,582				3,582
General Partners contributions			31			31
Distributions on common unit-based compensation		(1,026)				(1,026)
Distributions to Partners		(108,116)	(57,989)			(166,105)
Balance at December 31, 2009	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 13)		9,223				9,223

General Partners contribution (Note 11)			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

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

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 have a time-sharing agreement for the use of aircraft and we lease certain assets, including coal reserves and certain surface facilities, owned by SGP (Note 17).

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 Alliance WOR Properties, LLC (WOR Properties), Alliance Service, Inc. (Alliance Service), Alliance WOR Processing, LLC (WOR Processing), Backbone Mountain, LLC, Excel Mining, LLC, Gibson County Coal, LLC (Gibson County Coal), Gibson County Coal (South), LLC (Gibson South), Hopkins County Coal, LLC (Hopkins County Coal), Matrix Design Group, LLC (Matrix Design), MC Mining, LLC (MC Mining), Mettiki Coal, LLC (Mettiki (MD)), Mettiki Coal (WV), LLC (Mettiki (WV)), Mt. Vernon Transfer Terminal, LLC (Mt. Vernon), Penn Ridge Coal, LLC (Penn Ridge), Pontiki Coal, LLC (Pontiki), River View Coal, LLC (River View), Sebree Mining, LLC (Sebree), 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, 2011 and 2010, and results of our operations, cash flows and changes in partners capital for each of the three years in the period ended December 31, 2011. 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 accounts receivable, marketable securities, and accounts payable approximate fair value because of the short maturity of those instruments. At December 31, 2011 and 2010, the estimated fair value of long-term debt, including current maturities, was approximately $746.5 million and $809.5 million, respectively (Note 7).

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, 2011 and 2010.

Cash Management The cash flows from operating activities section of our Consolidated Statements of Cash Flows reflects an adjustment for $6.7 million representing book overdrafts at December 31, 2011. We had no book overdrafts at December 31, 2010 and 2009.

Inventories Coal inventories are stated at the lower of cost or market on a first-in, first-out basis. Supply inventories are stated at the lower of cost or market on 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 20 years. Depreciable lives for mining equipment and processing facilities range from 1 to 20 years. Depletable lives for mineral rights range from 2 to 20 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 20 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, 2011 and 2010, land and mineral rights include $66.9 million and $33.0 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, 2011 and 2010, capitalized mine development costs were $73.8 million and $35.3 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.

Table of Contents

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. The amount of impairment is measured by the difference between the carrying value and the fair value of the asset. We have not recorded an impairment loss for any of the periods presented.

Intangible Assets Costs allocated to contracts with covenants not to compete (Non-Compete Agreements) are amortized on a straight-line basis over the life of the Non-Compete Agreements. Amortization expense associated with Non-Compete Agreements was $1.4 million, $1.1 million and $0.5 million for the years ending December 31, 2011, 2010 and 2009, respectively. Our Non-Compete Agreements are included in other long-term assets on our consolidated balance sheets at December 31, 2011 and 2010. Our Non-Compete Agreements at December 31, are summarized as follows (in thousands):

	2011	2010
Non-Compete Agreements, original cost	$ 14,036	$ 13,689
Accumulated amortization	(3,807)	(2,419)
Non-Compete Agreements, net	$ 10,229	$ 11,270

Amortization expense related to Non-Compete Agreements is estimated to be $1.4 million per year in 2012-2015 and $1.3 million in 2016.

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

	2011	2010
Advance royalties, affiliates (Note 17)	$ 22,954	$ 19,955
Advance royalties, third-parties	12,522	12,296
Total advance royalties	$ 35,476	$ 32,251

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 15).

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 actuarial determined calculations (Note 16).

Table of Contents

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, Alliance Service, 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, rock dust sales (in 2009 only) 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, 2011 and 2010.

Pension Benefits Our defined benefit pension obligation and the related benefit cost are accounted for in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 715, *Compensation-Retirement Benefits*. Pension cost and obligations are actuarially determined and are affected by assumptions including expected return on plan assets, discount rates, compensation increases, employee turnover rates and health care cost trend rates. We evaluate our assumptions periodically and make adjustments to these assumptions and the recorded liability as necessary (Note 12).

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 awards, as appropriate over the requisite service period. Compensation expense is fully recognized on the grant date for SERP and Deferred Compensation Plan awards. The corresponding liability is classified as equity and included in limited partners capital in the consolidated financial statements (Note 13).

Net Income Per Unit Basic net income per limited partner unit is determined by dividing Net Income of ARLP available to Limited Partners by the weighted average number of outstanding common units. Diluted net income per unit is based on the combined weighted average number of common units and common unit equivalents outstanding (Note 11).

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, 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 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 10) and Mid-America Carbonates, LLC (MAC).

New Accounting Standards Issued and Adopted In December 2010, FASB issued Accounting Standards Update (ASU) 2010-29, *Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29). ASU 2010-29 amended FASB ASC 805, *Business Combinations*, to specify that if a public entity presents comparative financial statements and a business combination has occurred during the current reporting period, then the public entity should disclose revenues and earnings of the combined entity as though the business combination that occurred during the current year had occurred at the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures under FASB ASC 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenues and earnings. The adoption of the ASU 2010-29 amendments were effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The adoption of ASU 2010-29 did not have an impact on our consolidated financial statements.

New Accounting Standards Issued and Not Yet 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 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 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 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We do not anticipate the adoption of ASU 2011-04 on January 1, 2012 to 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 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 would include components of net income, and the second statement would include components of other comprehensive income (OCI). ASU 2011-05 does not change the items that must be reported in OCI. ASU 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and its provisions must 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. We do not anticipate the adoption of ASU 2011-05 on January 1, 2012 to have a material impact on our consolidated financial statements.

Table of Contents

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. INVENTORIES

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

	2011	2010
Coal	$ 7,794	$ 11,897
Supplies (net of reserve for obsolescence of $2,387 and $2,244, respectively)	26,043	19,651
Total inventory	$ 33,837	$ 31,548

5. PROPERTY, PLANT AND EQUIPMENT

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

	2011	2010
Mining equipment and processing facilities	$ 1,213,458	$ 1,056,670
Land and mineral rights	176,357	140,432
Buildings, office equipment and improvements	183,712	155,621
Construction in progress	171,957	76,766
Mine development costs	229,036	168,641
Property, plant and equipment, at cost	1,974,520	1,598,130
Less accumulated depreciation, depletion and amortization	(793,200)	(648,883)
Total property, plant and equipment, net	$ 1,181,320	$ 949,247

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 $5.4 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 lease was $1.9 million and $1.1 million as of December 31, 2011 and 2010, respectively, and amortization expense was $0.8 million, $0.3 million and $0.2 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Table of Contents

6. LONG-TERM DEBT

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

	2011	2010
Credit facility	$	$
Senior notes	54,000	72,000
Series A senior notes	205,000	205,000
Series B senior notes	145,000	145,000
Term loan	300,000	300,000
	704,000	722,000
Less current maturities	(18,000)	(18,000)
Total long-term debt	$ 686,000	$ 704,000

Credit Facility. Our Intermediate Partnership entered into a $150.0 million revolving credit facility (ARLP Credit Facility) dated September 25, 2007, which matures September 25, 2012. The ARLP Credit Facility was decreased to $142.5 million of availability on October 6, 2010 due to a defaulting lender, as discussed below. On September 30, 2009, our Intermediate Partnership entered into Amendment No. 2 (the Credit Amendment) to the ARLP Credit Facility. The Credit Amendment increased the annual capital expenditure limits under the ARLP Credit Facility. The new limits, before carry forward considerations and exclusion of capital expenditures related to acquisitions, are $250.0 million for 2012. The amount of any annual limit in excess of actual capital expenditures for that year carries forward and is added to the annual limit of the subsequent year. As a result, the capital expenditure limit for 2012 is approximately $460.0 million.

Pursuant to the Credit Amendment, the applicable margin for London Interbank Offered Rate borrowings under the ARLP Credit Facility was increased from a range of 0.625% to 1.150% (depending on the Intermediate Partnership s leverage margin) to a range of 1.115% to 2.000%, and the annual commitment fee was increased from a range of 0.15% to 0.35% (also depending on the Intermediate Partnership s leverage margin) to a range of 0.25% to 0.50%. In addition, the Credit Amendment includes certain changes relating to a defaulting lender, including changes which clarify that the overall ARLP Credit Facility commitment would be reduced by the commitment share of a defaulting lender but also provides our Intermediate Partnership with more flexibility in replacing a defaulting lender.

At December 31, 2011, we had $11.6 million of letters of credit outstanding with $130.9 million available for borrowing under the ARLP Credit Facility. We had no borrowings outstanding under the ARLP Credit Facility as of December 31, 2011 and 2010. We utilize the ARLP Credit Facility, as appropriate, to meet working capital requirements, anticipated capital expenditures, scheduled debt payments or distribution payments. We incur an annual commitment fee of 0.375% on the undrawn portion of the ARLP Credit Facility.

Lehman Commercial Paper, Inc. (Lehman), a subsidiary of Lehman Brothers Holding, Inc., held a 5%, or $7.5 million, commitment in the original $150 million ARLP Credit Facility. Lehman filed for protection under Chapter 11 of the Federal Bankruptcy Code in early October 2008. On February 11, 2010, the ARLP Partnership gave its lenders a notice of borrowing under the ARLP Credit Facility and, in response to that notice, Lehman notified the ARLP Partnership that it would not fund its proportionate share of the borrowing. As a result, as of February 11, 2010, Lehman became a defaulting lender and on October 6, 2010, was removed as a commitment holder under the ARLP Credit Facility. Consequently, availability for borrowing under the ARLP Credit Facility was reduced by $7.5 million on October 6, 2010. The ARLP Credit Facility is underwritten by a syndicate of eleven financial institutions (excluding Lehman) with no individual institution representing more than 11.9% of the $142.5 million revolving credit facility. In the event any other financial institution in the ARLP Partnership s syndicate does not fund its future borrowing requests, the ARLP Partnership s borrowing available under the ARLP Credit Facility would be reduced. The obligations of the lenders under the ARLP Credit Facility are individual obligations and the failure of one or more lenders does not relieve the remaining lenders of their funding obligations.

Senior Notes. Our Intermediate Partnership has $54.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in three 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, which bear interest at 6.72% and mature on June 26, 2018 with interest payable semi-annually.

Term Loan. On December 29, 2010, our Intermediate Partnership entered into a Term Loan Agreement, (the Term Loan Agreement) with various financial institutions for a term loan (the Term Loan) in the aggregate principal amount of $300 million. The Term Loan bears interest at a variable rate plus an applicable margin which fluctuates depending upon whether we elect the Term Loan (or a portion thereof) to bear interest on the Base Rate or the Eurodollar Rate (as defined in the Term Loan Agreement). We elected the Eurodollar Rate as of December 31, 2011 which, with applicable margin, was 2.3%. Interest is payable quarterly with principal due as follows: $15 million due per quarter beginning March 31, 2013 through December 31, 2013, $18.75 million due per quarter beginning March 31, 2014 through September 30, 2015 and the balance of $108.75 million due on December 31, 2015. 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 Term Loan Agreement. Upon a change of control (as defined in the Term Loan Agreement), the unpaid principal amount of the loan, all interest thereon and all other amounts payable under the Term Loan Agreement will become due and payable.

The net proceeds of the Term Loan have been used for the general corporate, business or working capital purposes of the Intermediate Partnership and its subsidiaries. We incurred debt issuance costs of approximately $1.4 million in 2010 associated with the ARLP Term Loan and $0.3 million in 2009 associated with the ARLP Credit Facility, which have been deferred and are being amortized as a component of interest expense over the term of the respective notes.

The ARLP Credit Facility, Senior Notes, Series A and Series B Senior Notes (collectively, the 2008 Senior Notes) and the Term Loan Agreement (collectively, the ARLP Debt Arrangements) are guaranteed by all of the 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, as defined in the ARLP Debt Arrangements, the following: (i) debt to cash flow ratio of not more than 3.0 to 1.0 and (ii) cash flow to interest expense ratio of not less than 4.0 to 1.0 in both cases, during the four most recently ended fiscal quarters. The ARLP Credit Facility, Senior Notes and the 2008 Senior Notes limit our Intermediate Partnership s maximum annual capital expenditures, excluding acquisitions, as described above. The debt to-cash-flow ratio and cash-flow-to-interest-expense ratio were 1.2 to 1.0 and 16.1 to 1.0, for the trailing twelve months ended December 31, 2011. The capital expenditure limit for 2011 was $531.9 million and actual capital expenditures were $321.9 million for the year ended December 31, 2011. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2011.

Other. In addition to the letters of credit available under the ARLP 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, 2011, 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.

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

Year Ending December 31,	
2012	$ 18,000
2013	78,000
2014	93,000
2015	370,000
2016	
Thereafter	145,000
	$ 704,000

7. FAIR VALUE MEASUREMENTS

We apply the provisions of FASB ASC 820, *Fair Value Measurements and Disclosures* which, among other things, defines fair value, requires enhanced 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 accounts receivable and accounts payable approximate fair value because of the short maturity of those instruments. At December 31, 2011 and 2010, the estimated fair value of our debt, including current maturities, was approximately $746.5 million and $809.5 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 6).

8. 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).

Table of Contents

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. For the years ended December 31, 2011, 2010 and 2009, we allocated to our managing general partner incentive distributions of $83.4 million, $66.8 million and $58.0 million, respectively. The following table summarizes the quarterly per unit distribution paid during the respective quarter:

	Year		
	2011	**2010**	**2009**
First Quarter	$ 0.8600	$ 0.775	$ 0.715
Second Quarter	$ 0.8900	$ 0.790	$ 0.730
Third Quarter	$ 0.9225	$ 0.810	$ 0.745
Fourth Quarter	$ 0.9550	$ 0.830	$ 0.760

On January 27, 2012, we declared a quarterly distribution of $0.99 per unit, totaling approximately $60.2 million (which includes our managing general partner s incentive distributions), on all our common units outstanding, which was paid on February 14, 2012, to all unitholders of record on February 7, 2012.

9. INCOME TAXES

Our subsidiary, Alliance Service, is subject to federal and state income taxes. Alliance Service s income is principally due to its subsidiary, Matrix Design. Alliance Service 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,		
	2011	**2010**	**2009**
Current:			
Federal	$ (337)	$ 1,517	$ 620
State	(75)	240	118
	(412)	1,757	738
Deferred:			
Federal	(17)	(14)	(25)
State	(2)	(2)	(5)
	(19)	(16)	(30)
Income tax expense (benefit)	$ (431)	$ 1,741	$ 708

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,		
	2011	**2010**	**2009**
Income taxes at statutory rate	$ 136,122	$ 112,966	$ 67,569
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(136,257)	(111,345)	(66,939)
Increase/(decrease) resulting from:			
State taxes, net of federal income tax	(8)	162	70
Other	(288)	(42)	8

Income tax expense (benefit)	$ (431)	$ 1,741	$ 708

10. 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 leaseback of certain reserves and surface rights, a coal handling and services agreement and a backstop equipment financing facility. Our initial investment at the Transaction Date, consummated utilizing existing cash on hand, was $69.5 million and we committed to additionally fund approximately $330.5 million to $455.5 million over the next three to four years, of which $24.0 million was funded between the Transaction Date and December 31, 2011. We expect to fund these additional commitments utilizing existing cash balances, future cash flows from operations, borrowings under revolving credit facilities and cash provided by 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 and has a remaining commitment of $34.6 million for further 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 leaseback of the coal reserves and the funding of development of those coal reserves, White Oak to pay WOR Properties earned royalties when coal production begins 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.

In addition, WOR Properties committed up to $54.6 million to purchase and leaseback up to an additional 100.0 million tons of coal reserves from White Oak during the next 12 to 24 months.

Equity Investment Series A Units

Concurrent with the Reserve Acquisition, WOR Processing made an 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. In 2011, subsequent to the Transaction Date, WOR Processing purchased $7.0 million of additional Series A Units, bringing the total investment in Series A Units to $42.7 million at December 31, 2011.

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, 2011 was 6.6% 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 undertook an extensive review of all such rights provided to WOR Processing and us and concluded 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 four 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, 2011, WOR Processing had invested $42.7 million in Series A Units of White Oak equity, which represents our current maximum exposure to loss as a result of our involvement with White Oak. White Oak made no distributions from the Transaction Date through December 31, 2011.

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. 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 period from the Transaction Date through December 31, 2011, we were allocated losses of $4.3 million. There were no losses allocated to us for any period prior to the Transaction Date.

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. The expected cost to construct the facilities contemplated by the Services Agreement is approximately $99.5 million and will be expended by WOR Processing over the next three years. 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 not utilized any amounts available under the Construction Loan as of December 31, 2011.

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. White Oak had not utilized any amounts available under the equipment financing as of December 31, 2011.

11. 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 of ARLP is allocated to the general partners and limited partners in accordance with their respective partnership percentages, after giving effect to any special income or expense allocations, including incentive distributions to our managing general partner, the holder of the IDR pursuant to our partnership agreement, which are declared and paid following the end of each quarter (Note 8). 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.

The following is a reconciliation of Net Income of ARLP and net income used for calculating EPU and the weighted average units used in computing EPU for the years ended December 31, 2011, 2010 and 2009, respectively (in thousands, except per unit data):

	Year Ended December 31,		
	2011	**2010**	**2009**
Net Income of ARLP	$ 389,353	$ 321,017	$ 192,157
Adjustments:			
General partner s priority distributions	(85,066)	(68,114)	(57,955)
General partners 2% equity ownership	(6,185)	(5,058)	(2,684)
General partners special allocation of certain general and administrative expenses	5,000		
Limited partners interest in Net Income of ARLP	303,102	247,845	131,518
Less:			
Distributions to participating securities	(1,985)	(1,244)	(1,002)
Undistributed earnings attributable to participating securities	(2,337)	(1,282)	(185)
Net Income of ARLP available to limited partners	$ 298,780	$ 245,319	$ 130,331
Weighted average limited partner units outstanding Basic and Diluted (1)	36,769	36,710	36,656
Basic and Diluted Net Income of ARLP per limited partner unit (1)	$ 8.13	$ 6.68	$ 3.56

(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, 2011, LTIP, SERP and Deferred Compensation Plan units of 409,969 were considered anti-dilutive. For the years ended December 31, 2010 and 2009, LTIP units of 232,042 and 176,743, respectively, were considered anti-dilutive.

During 2009 and 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 2009 and 2010. Effective January 1, 2011, settlement of accounts under these plans will be only in common units of ARLP (Note 13). As a result, phantom units associated with these plans were considered in the calculation of basic or diluted units for the year ended December 31, 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).

Table of Contents

During 2011, our managing general partner made a capital contribution of $5.0 million 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 17).

12. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans Our eligible employees currently participate in a defined contribution profit sharing and savings plan (PSSP) that we sponsor. The PSSP covers substantially all regular full-time employees. PSSP participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. We make matching contributions based on a percent of an employee s eligible compensation and also make an additional nonmatching contribution. Our contribution expense for the PSSP was approximately $15.6 million, $13.3 million and $11.2 million for the years ended December 31, 2011, 2010 and 2009, 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.

Beginning with the year ended December 31, 2009, we adopted amendments to FASB ASC 715, *Compensation Retirement Benefits*. These amendments required us to provide more detailed annual disclosures of Pension Plan assets, concentrations of risk within Pension Plan assets, and valuation techniques used to measure the fair value of Pension Plan assets.

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2011 and 2010 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements at December 31, 2011 and 2010, respectively (dollars in thousands):

	2011	2010
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 57,278	$ 57,790
Service cost	2,312	2,214
Interest cost	3,184	2,924
Actuarial (gain) loss	12,260	(4,625)
Benefits paid	(1,304)	(1,025)
Benefit obligations at end of year	73,730	57,278
Change in plan assets:		
Fair value of plan assets at beginning of year	43,982	38,094
Employer contribution	4,860	3,159
Actual return on plan assets	(1,346)	3,754
Benefits paid	(1,304)	(1,025)
Fair value of plan assets at end of year	46,192	43,982
Funded status at the end of year	$ (27,538)	$ (13,296)
Amounts recognized in balance sheet:		
Non-current liability	$ (27,538)	$ (13,296)
	$ (27,538)	$ (13,296)
Amounts recognized in accumulated other comprehensive income consists of:		
Net actuarial loss	$ (28,620)	$ (11,673)
Weighted-average assumptions to determine benefit obligations as of December 31,		
Discount rate	4.49%	5.56%
Expected rate of return on plan assets	7.90%	8.35%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,		
Discount rate	5.56%	5.88%
Expected return on plan assets	8.35%	8.35%

The actuarial loss component of the change in benefit obligation in 2011 was primarily attributable to decreases in the discount rate and the actual rate of return on plan assets at December 31, 2011 compared to December 31, 2010. The actuarial gain component of the change in benefit obligation in 2010 was primarily attributable to an update in assumptions related to Pension Plan participant retirement age.

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 Pension Plan s expected long-term rate of return of 7.90% is determined by the above factors and an asset allocation assumption of 60.0% invested in domestic equity securities with an expected long-term rate of return of 9.10%, 20.0% invested in international equities with an expected long-term rate of return of 5.84% and 20.0% invested in fixed income securities with an expected long-term rate of return of 6.60%. 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 (2.7)% and 10.4% for the years ended December 31, 2011 and 2010, respectively.

Table of Contents

	2011	2010	2009
		(in thousands)	
Components of net periodic benefit cost:			
Service cost	$ 2,312	$ 2,214	$ 2,580
Interest cost	3,184	2,924	3,083
Expected return on plan assets	(3,877)	(3,270)	(2,518)
Amortization of net loss	537	366	1,499
Net periodic benefit cost	$ 2,156	$ 2,234	$ 4,644

	2011	2010
	(in thousands)	
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive income:		
Net actuarial (gain) loss	$ 17,483	$ (5,110)
Reversal of amortization item:		
Net actuarial gain	(537)	(366)
Total recognized in accumulated other comprehensive (income) loss	16,946	(5,476)
Net periodic benefit cost	2,156	2,234
Total recognized in net periodic benefit cost and accumulated other comprehensive loss	$ 19,102	$ (3,242)

Estimated future benefit payments as of December 31, 2011 are as follows (in thousands):

Year Ending December 31,	
2012	$ 1,434
2013	1,638
2014	1,846
2015	2,096
2016	2,349
2017-2021	16,137
	$ 25,500

We expect to contribute $5.4 million to the Pension Plan in 2012. 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 2012 fiscal year is $1.7 million.

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

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

Table of Contents

We had unfunded benefit obligations of approximately $27.5 million and $13.3 million at December 31, 2011 and 2010. 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, 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,

	2011	**2010**
Domestic equity securities	64%	59%
Foreign equity securities	16%	21%
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.

Table of Contents

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, 2011			December 31, 2010		
	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	$ 467	$	$	$ 839	$	$
Equity securities (a):						
U.S. large-cap growth	5,404			6,151		
U.S. large-cap value	6,744			5,922		
International large-cap core				2,725		
Fixed income securities:						
U.S. Treasury securities (b)	1,815			1,552		
Corporate bonds (c)		2,093			1,754	
Preferred stock (a)				184		
Taxable municipal bonds (c)		315			271	
International bonds (c)		528			673	
Equity mutual funds (d):						
U.S. large-cap growth		3,902			225	
U.S. large-cap value		2,628			747	
U.S. mid-cap growth		3,688			4,172	
U.S. mid-cap value		3,782			4,059	
U.S. small cap growth		1,887			2,627	
U.S. small cap value		1,907			2,195	
International		5,513			4,020	
Emerging Markets		1,849			2,534	
Fixed income mutual funds (d):						
Corporate bond		602			879	
Mortgage backed-securities		1,037			722	
Intermediate investment grade bond		1,444			1,016	
High yield bond		515			644	
International bond		242			297	
Stock market index options (e):						
Puts		116			212	
Calls		(361)			(438)	
Accrued income (f)		75				
Total	$ 14,430	$ 31,762	$	$ 17,373	$ 26,609	$

(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 not 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, 2011.

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.

13. 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. The aggregate number of units reserved for issuance under the LTIP was 1.2 million prior to October 23, 2009. On October 23, 2009, the LTIP was amended to increase the number of common units available for issuance from 1.2 million to 3.6 million.

On January 25, 2011, the Compensation Committee determined that the vesting requirements for the 2008 grants of 91,100 restricted units (which is net of 2,500 forfeitures) had been satisfied as of January 1, 2011. As a result of this vesting, on February 11, 2011, we issued 58,886 unrestricted common units to LTIP participants. The remaining units were settled in cash to satisfy the tax withholding obligations for the LTIP participants. On February 6, 2012, the Compensation Committee authorized additional grants of 106,779 restricted units.

During the years ended December 31, 2011, 2010, and 2009 and the three months ended December 31, 2008, we issued grants of 108,416 units, 138,130 units, 9,625 units and 141,145 units, respectively. 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. Grants issued during the year ended December 31, 2009 and the three months ended December 31, 2008 vest on January 1, 2012. Vesting of all grants is subject to the satisfaction of certain financial tests, which management currently believes is probable. As of December 31, 2011, 13,098 of these outstanding LTIP grants have been forfeited. 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 (which is 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 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, 2012 vesting and subsequent issuance of 93,938 common units, 2.3 million units remain available for issuance in the future, assuming that all grants issued in 2010 and 2011 and currently outstanding are settled with common units, without reduction for tax withholding, and no future forfeitures occur.

For the years ended December 31, 2011, 2010 and 2009, our LTIP expense was $5.3 million, $4.1 million and $3.6 million, respectively. The total obligation associated with the LTIP as of December 31, 2011 and 2010 was $9.6 million and $7.6 million, respectively, and is included in limited partners capital in our consolidated balance sheets.

The fair value of the 2011, 2010 and 2009 grants is based upon the intrinsic value at the date of grant, which was $66.84, $39.59 and $25.60 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, 2011 is as follows:

Non-vested grants at January 1, 2011	372,723
Granted	108,416
Vested	(91,100)
Forfeited	(5,821)
Non-vested grants at December 31, 2011	384,218

As of December 31, 2011, there was $6.5 million in total unrecognized compensation expense related to the non-vested LTIP grants that are expected to vest. That expense is expected to be recognized over a weighted-average period of 1.4 years. As of December 31, 2011, the intrinsic value of the non-vested LTIP grants was $29.0 million.

Table of Contents

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, 2011 and 2010, SERP and Deferred Compensation Plan participant notional account balances were credited with a total of 13,725 and 13,944 phantom units, respectively, and the fair value of these phantom units was $72.83 and $65.76, respectively, on a weighted-average basis. Total SERP and Deferred Compensation Plan expense was approximately $1.0 million, $3.9 million and $3.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

As of December 31, 2011, there were 153,975 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 $11.6 million. As of December 31, 2011, the total obligation associated with the SERP and Deferred Compensation Plan was $10.2 million and is included in the partners capital-limited partners line item in our consolidated balance sheets. On February 14, 2012, we issued 5,270 ARLP common units to directors under the Deferred Compensation Plan.

14. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2011	**2010** (in thousands)	**2009**
Cash Paid For:			
Interest	$ 36,188	$ 30,787	$ 32,186
Income taxes	$ 300	$ 1,803	$ 225
Non-Cash Activity:			
Accounts payable for purchase of property, plant and equipment	$ 24,979	$ 13,339	$ 20,819
Market value of common units vested in Long-Term Incentive Plan before minimum statutory tax withholding requirements	$ 6,572	$ 3,396	$ 2,333
Assets acquired by capital lease	$ 3,525	$	$

Table of Contents

15. 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, 2011, we had approximately $70.6 million in surety bonds outstanding to secure the performance of our reclamation obligations.

Discounting resulted in reducing the accrual for asset retirement obligations by $71.3 million and $72.8 million at December 31, 2011 and 2010, respectively. Estimated payments of asset retirement obligations as of December 31, 2011 are as follows (in thousands):

Year Ending December 31,	
2012	$ 1,506
2013	1,143
2014	1,257
2015	1,877
2016	15,265
Thereafter	122,568
Aggregate undiscounted asset retirement obligations	143,616
Effect of discounting	(71,274)
Total asset retirement obligations	72,342
Less: current portion	(1,506)
Asset retirement obligations	$ 70,836

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

	Year ended December 31, 2011	**2010**
Beginning balance	$ 58,227	$ 55,851
Accretion expense	2,546	2,574
Payments	(1,920)	(966)
Allocation of liability associated with acquisition, mine development and change in assumptions	13,489	768
Ending balance	$ 72,342	$ 58,227

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.

100

Table of Contents

For the year ended December 31, 2010, the allocation of liability associated with acquisition, mine development and change in assumptions is a net increase of $0.8 million which was primarily attributable to increased refuse site reclamation disturbances at our Hopkins County Coal operation 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 a reduction in the impoundment cover material at Pontiki and MC Mining.

16. 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 4.25% and 5.38% at December 31, 2011 and 2010, respectively, and for workers compensation was 3.75% and 4.70% at December 31, 2011 and 2010, respectively.

The black lung and workers compensation expense consists of the following components for the year ended December 31, 2011, 2010 and 2009 (in thousands):

	2011	2010	2009
Black lung benefits:			
Service cost	$ 3,345	$ 2,359	$ 2,187
Interest cost	2,382	1,857	1,535
Net amortization	(222)	(176)	(536)
Total black lung	5,505	4,040	3,186
Workers compensation expense	18,996	16,776	21,585
Total expense	$ 24,501	$ 20,816	$ 24,771

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, 2011 and 2010 (in thousands);

	2011	2010
Net actuarial loss	$ 4,570	$ 6,871
Reversal of amortization item:		
Net actuarial loss	222	176
Total recognized in accumulated other comprehensive income	$ 4,792	$ 7,047

Table of Contents

The following is a reconciliation of the changes in workers compensation liability (including current and long-term liability balances) at December 31, 2011 and 2010 (in thousands):

	2011	2010
Beginning balance	$ 67,687	$ 63,220
Accruals	22,254	20,047
Payments	(11,235)	(9,944)
Interest accretion	3,174	3,332
Valuation gain	(8,679)	(8,968)
Ending balance	$ 73,201	$ 67,687

The following is a reconciliation of the changes in black lung benefit obligations at December 31, 2011 and 2010 (in thousands):

	2011	2010
Benefit obligations at beginning of year	$ 45,666	$ 34,855
Service cost	3,345	2,359
Interest cost	2,382	1,857
Actuarial loss	4,570	6,871
Benefits and expenses paid	(358)	(276)
Benefit obligations at end of year	$ 55,605	$ 45,666
Amount recognized in accumulated other comprehensive income consist of:		
Net actuarial loss	$ 11,840	$ 7,048

Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for black lung and workers compensation benefits at December 31, 2011 and 2010 (in thousands):

	2011	2010
Black lung claims	$ 55,605	$ 45,666
Workers compensation claims	73,201	67,687
Total obligations	128,806	113,353
Less current portion	(9,511)	(8,518)
Non-current obligations	$ 119,295	$ 104,835

Both the black lung and workers compensation obligations were unfunded at December 31, 2011 and 2010.

As of December 31, 2011 and 2010, we had $69.6 million, in surety bonds and letters of credit outstanding to secure workers compensation obligations.

The Patient Protection and Affordable Care Act, which was signed into law by President Obama on March 23, 2010, amended previous legislation related to coal workers 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 the December 31, 2010 measurement date. As of December 31, 2010, we recorded this estimate as an increase to our black lung liability and a decrease to our actuarial gain included in accumulated other comprehensive income on our consolidated balance sheet. 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. We will continue to evaluate the impact of these changes on such claims and record any necessary changes in the period in which the impact is estimable.

17. RELATED-PARTY TRANSACTIONS

The board of directors of our managing general partner (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. 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 an Amended and Restated Administrative Services Agreement (the Administrative Services Agreement) with our managing general partner, our Intermediate Partnership, AHGP and its general partner AGP, and Alliance Resource Holdings II, Inc. (ARH II), the indirect parent of SGP. The Administrative Services Agreement superseded the administrative services agreement signed in connection with the AHGP IPO in 2006. Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services to our managing general partner, AHGP, AGP, ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these affiliates as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under the Administrative Services Agreement of $0.4 million, $0.3 million and $0.4 million for the years ended December 31, 2011, 2010 and 2009, respectively, from AHGP and $0.2 million, $0.2 million and $0.5 million from ARH II for the years ended December 31, 2011, 2010 and 2009, respectively.

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, director fees and expenses, management s salaries and related benefits (including incentive compensation), and accounting, budgeting, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $0.7 million, $1.3 million and $1.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Managing General Partner Contribution During December 2011, an affiliated entity controlled by Mr. Craft contributed $5.0 million to AHGP for the purpose of funding certain of our general and administrative expenses. Upon AHGP s receipt of this contribution, it contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made a special allocation to our managing general partner of certain general and administrative expenses equal to the amount of its contribution (Note 11).

White Oak On September 22, 2011, we entered into a series of transactions with White Oak and related entities to support development of a longwall mining operation currently under construction. The transactions feature several components, including an equity investment containing certain distribution and liquidation preferences, the acquisition and leaseback of certain reserves and surface rights, a coal handling and services agreement and a backstop equipment financing facility. See Note 10 for further information on these related party transactions.

SGP Land, LLC On May 2, 2007, SGP Land, a subsidiary of our special general partner, entered into a time-sharing agreement with Alliance Coal, our operating subsidiary, concerning the use of aircraft owned by SGP Land. In accordance with the provisions of the time-sharing agreement as amended, we reimbursed SGP Land $1.0 million, $0.8 million and $0.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, for use of the aircraft.

Table of Contents

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 $0.3 million during each of the years ended December 31, 2011, 2010 and 2009. As of December 31, 2011, $2.4 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, 2011, 2010 and 2009. As of December 31, 2011, $20.6 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, 2011, 2010 and 2009.

We have a noncancelable lease arrangement with SGP for the coal preparation plant and ancillary facilities at the Gibson County Coal mining complex. 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, 2011, 2010 and 2009 were $0.8 million, $2.6 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 (Note 6). SGP previously guaranteed $5.0 million of these outstanding letters of credit. These guarantees were released on May 4, 2011.

18. COMMITMENTS AND CONTINGENCIES

Commitments We lease buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. We also have a noncancelable lease with SGP (Note 17) and a noncancelable lease for equipment under a capital lease obligation. Future minimum lease payments are as follows (in thousands):

	Capital	Other Operating Leases		
Year Ending December 31,	**Lease**	**Affiliate**	**Others**	**Total**
2012	$ 758	$ 240	$ 1,512	$ 1,752
2013	701		824	824
2014	630		367	367
2015	617		367	367
2016	617		367	367
Thereafter	51		643	643
Total future minimum lease payments	$ 3,374	$ 240	$ 4,080	$ 4,320
Less: amount representing interest	(201)			
Present value of future minimum lease payments	3,173			
Less: current portion	(676)			
Long-term capital lease obligation	$ 2,497			

Rental expense (including rental expense incurred under operating lease agreements) was $5.3 million, $7.2 million and $6.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Contractual Commitments In connection with planned capital projects, we have contractual commitments of approximately $161.9 million at December 31, 2011. As of December 31, 2011, we had commitments to purchase, from external production sources, coal at an estimated cost up to $37.5 million in 2012.

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. Our various investments related to White Oak as of December 31, 2011 were $93.5 million and we expect to additionally fund approximately $306.5 million to $431.5 million over the next three to four years. We plan to utilize existing cash balances, future cash flows from operations, borrowings under revolving 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 Note 10.

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

Other During September 2011, we completed our annual property and casualty insurance renewal with various insurance coverages effective October 1, 2011. 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.

19. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

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

		Year Ended December 31,		
	Segment (Note 20)	**2011 (1)**	**2010 (1)**	**2009**
Customer A	Illinois Basin	$ 249,047	$ 191,225	$ 140,921
Customer B	Illinois Basin	231,838	279,516	120,915
Customer C	Northern Appalachia			129,265
Customer D	Illinois Basin			122,961

Trade accounts receivable from these customers totaled approximately $34.1 million and $35.9 million at December 31, 2011 and 2010, respectively. Our bad debt experience has historically been insignificant. Financial conditions of our customers could result in a material change to our bad debt expense in future periods. We have various coal agreements with our significant customers with expiration dates ranging from 2012 to 2016.

(1) Customer C & D are below the 10% threshold of total revenues for 2011 and 2010.

Table of Contents

20. SEGMENT INFORMATION

We operate in the eastern U.S. as a producer and marketer of coal to major utilities and industrial users. We aggregate multiple operating segments into 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. Similar economic characteristics for 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 includes our activities associated with the White Oak longwall Mine No. 1 development project. These activities currently encompass an equity investment in White Oak, the purchase and funding of development of the White Oak coal reserves and the construction and operation of surface facilities.

The Illinois Basin reportable segment is comprised of multiple operating segments, including Webster County Coal s Dotiki mining complex, Gibson mining complex which includes the Gibson North mine and the Gibson South project, Hopkins County Coal s Elk Creek mining complex, White County Coal s Pattiki mining complex, Warrior s mining complex, River View s mining complex, which initiated operations in 2009, the Sebree property and certain properties of Alliance Resource Properties, and ARP Sebree, LLC. On July 25, 2011, the board of directors of our managing general partner approved development of the Gibson South mine, which is currently underway. We are in the process of permitting the Sebree property for future mine development.

The Central Appalachian reportable segment is comprised of two operating segments, the Pontiki and MC Mining mining complexes.

The 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 mine and the Penn Ridge property. In May 2010, incidental production began from mine development activities at Tunnel Ridge, however, longwall production is not anticipated until the second quarter of 2012. We are in the process of permitting the Penn Ridge property for future mine development.

The White Oak reportable segment is comprised of two operating segments, WOR Properties and WOR Processing. WOR Processing includes both the surface operations at White Oak currently under construction and the equity investment in White Oak. WOR Properties owns coal reserves acquired from White Oak and is committed to fund future development of these reserves by White Oak. The White Oak reportable segment will also include loans made in the future to White Oak for the construction of surface facilities and the financing of mining equipment (Note 10).

Other and Corporate includes marketing and administrative expenses, Matrix Design, Alliance Design (collectively, Matrix Design and Alliance Design are referred to as Matrix Group), the Mt. Vernon dock activities, coal brokerage activity, our equity investment in MAC and certain properties of Alliance Resource Properties. Reportable segment results as of and for the years ended December 31, 2011, 2010 and 2009 are presented below.

	Illinois Basin	Central Appalachia	Northern Appalachia	White Oak (in thousands)	Other and Corporate	Elimination (1)	Consolidated
Reportable segment results as of and for the year ended December 31, 2011 were as follows:							
Total revenues (2)	$ 1,313,148	$ 206,323	$ 274,233	$	$ 65,024	$ (15,168)	$ 1,843,560
Segment Adjusted EBITDA Expense (3)	786,116	151,101	203,317	155	59,526	(15,168)	1,185,047
Segment Adjusted EBITDA (4)	505,113	53,729	62,395	(4,407)	6,340		623,170
Total assets	787,923	96,099	452,407	89,690	306,254	(855)	1,731,518
Capital expenditures (5)	153,118	28,477	137,040	51,198	2,888		372,721
Reportable segment results as of and for the year ended December 31, 2010 were as follows:							
Total revenues (2)	$ 1,202,442	$ 165,175	$ 219,211	$	$ 45,052	$ (21,815)	$ 1,610,065
Segment Adjusted EBITDA Expense (3)	717,040	128,318	163,876		38,743	(21,815)	1,026,162
Segment Adjusted EBITDA (4)	460,592	36,714	46,702		6,311		550,319
Total assets	745,626	81,818	313,515		364,405	(4,086)	1,501,278
Capital expenditures	149,149	10,012	128,961		1,752		289,874
Reportable segment results as of and for the year ended December 31, 2009 were as follows:							
Total revenues (2)	$ 883,800	$ 181,029	$ 148,253	$	$ 40,441	$ (22,492)	$ 1,231,031
Segment Adjusted EBITDA Expense (3)	532,549	138,412	124,176		30,789	(22,122)	803,804
Segment Adjusted EBITDA (4)	315,542	41,149	15,552		9,621	(370)	381,494
Total assets	725,243	86,011	199,443		43,132	(2,429)	1,051,400
Capital expenditures	228,522	14,895	81,009		3,736		328,162

(1) The elimination column represents the elimination of intercompany transactions and is primarily comprised of sales from Matrix Group and MAC to our mining operations.

(2) Revenues included in the Other and Corporate column are primarily attributable to Matrix Group revenues, Mt. Vernon transloading revenues, administrative service revenues from affiliates, MAC rock dust revenues (2009 only) and brokerage sales.

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

Table of Contents

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

	Year Ended December 31,		
	2011	2010	2009
Segment Adjusted EBITDA Expense	$ 1,185,047	$ 1,026,162	$ 803,804
Outside coal purchases	(54,280)	(17,078)	(7,524)
Other income	983	851	1,247
Operating expenses (excluding depreciation, depletion and amortization)	$ 1,131,750	$ 1,009,935	$ 797,527

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

	Year Ended December 31,		
	2011	2010	2009
Consolidated Segment Adjusted EBITDA	$ 623,170	$ 550,319	$ 381,494
General and administrative	(52,334)	(50,818)	(41,117)
Depreciation, depletion and amortization	(160,335)	(146,881)	(117,524)
Interest expense, net	(21,579)	(29,862)	(29,798)
Income tax (expense) benefit	431	(1,741)	(708)
Net income	389,353	321,017	192,347
Net income attributable to noncontrolling interest			(190)
Net Income of ARLP	$ 389,353	$ 321,017	$ 192,157

(5) Capital expenditures shown above for the year ended December 31, 2011, include reserves acquired from White Oak and related development funding of $33,841 and $16,959, respectively (Note 10).

21. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our consolidated quarterly operating results in 2011 and 2010 is as follows (in thousands, except unit and per unit data):

	Quarter Ended			
	March 31, 2011	June 30, 2011	September 30, 2011	December 31, 2011 (1) (2)
Revenues	$ 423,258	$ 457,946	$ 487,747	$ 474,609
Income from operations	103,769	107,179	112,115	89,859
Income before income taxes	95,151	98,503	103,776	91,492
Net income	95,380	98,178	104,093	91,702
	$ 1.99	$ 2.04	$ 2.16	$ 1.93

Basic and diluted net income per limited partner unit				
Weighted average number of units outstanding basic and diluted	36,748,915	36,775,741	36,775,741	36,775,741

	Quarter Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010 (1)
Revenues	$ 380,661	$ 400,343	$ 410,448	$ 418,613
Income from operations	82,850	92,971	81,322	94,626
Income before income taxes	75,156	85,884	74,196	87,522
Net income	74,988	85,461	73,201	87,367
Basic and diluted net income per limited partner unit	$ 1.56	$ 1.82	$ 1.48	$ 1.82
Weighted average number of units outstanding basic and diluted	36,690,803	36,716,855	36,716,855	36,716,855

(1) The comparability of our December 31, 2011 and 2010 quarterly results were affected by a $13.6 million and $13.9 million decrease in our workers compensation liability, excluding discount rate changes, due to the completion of our annual actuarial study, which reflected a favorable development in our disability emergence patterns and claims estimates, as well as improved visibility of our Mettiki (WV) claims experience.

(2) During the quarter ended December 31, 2011, the ARLP Partnership corrected the interest rate used to account for capitalized interest to utilize the Partnership s overall borrowing rate. This correction resulted in a $10.0 million increase in property, plant and equipment (net of $1.2 million of related depreciation, depletion and amortization) and an $11.2 million offsetting decrease to interest expense ($9.4 million of which was related to prior years). Management concluded the effect of the correction was not material to prior periods, 2011 results or the trend of earnings.

22. SUBSEQUENT EVENTS

On February 23, 2012, Alliance Coal entered into a definitive agreement with Green River Collieries, LLC (Green River) to acquire substantially all of its coal related assets located in Webster and Hopkins Counties, Kentucky. The transaction includes the Onton No. 9 mining complex and an estimated 40.0 million tons of coal reserves in the West Kentucky No. 9 coal seam. We currently anticipate closing of the transaction following the completion by Green River of certain closing requirements.

Other than the event described above and those events described in Notes 8 and 13, there were no other subsequent events.

Table of Contents

SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	Balance At Beginning of Year	Additions Charged to Income	Deductions	Balance At End of Year
		(in thousands)		
2011				
Allowance for doubtful accounts	$	$	$	$
2010				
Allowance for doubtful accounts	$	$	$	$
2009				
Allowance for doubtful accounts	$	$	$	$

Table of Contents

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. We maintain controls and procedures designed to provide reasonable assurance that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Exchange Act) as of December 31, 2011. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures are effective as of December 31, 2011.

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

Table of Contents

Management s Annual Report on Internal Control over Financial Reporting. Management of the ARLP Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Exchange Act. The ARLP Partnership s internal control over financial reporting is designed to provide reasonable assurance to our management and Board of Directors of our managing general partner regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the ARLP Partnership s assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are complemented by a staff of competent business process owners and an internal auditor supported by competent and qualified external resources used to assist in testing the operating effectiveness of the ARLP Partnership s internal control over financial reporting. Management concluded that the design and operations of our internal controls over financial reporting at December 31, 2011 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the ARLP Partnership.

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on its assessment, management concluded that, as of December 31, 2011, the ARLP Partnership s internal control over financial reporting was effective based on those criteria, and management believes that we have no material internal control weaknesses in our financial reporting process.

Ernst & Young, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2011, as stated in their report which is included herein.

Changes in Internal Controls Over Financial Reporting. There has been no change in our internal controls over financial reporting (as defined in Rule 13a-15(f) or Rule 15d-15(f) of the Exchange Act) in the three months ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Table of Contents

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 Alliance Resource Partners, L.P. s (the Partnership) internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Partnership s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Alliance Resource Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet Alliance Resource Partners, L.P. and subsidiaries as of December 31, 2011, and the related consolidated statements of income, cash flows, and partners capital for the year then ended and our report dated February 28, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 28, 2012

Table of Contents

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

PART III

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

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

Name	Age	Position With Our Managing General Partner
Joseph W. Craft III	61	President, Chief Executive Officer and Director
Brian L. Cantrell	52	Senior Vice President and Chief Financial Officer
R. Eberley Davis	54	Senior Vice President, General Counsel and Secretary
Robert G. Sachse	63	Executive Vice President Marketing
Charles R. Wesley	57	Executive Vice President and Director
Thomas M. Wynne	55	Senior Vice President and Chief Operating Officer
Michael J. Hall	67	Director and Member of Audit* and Compensation Committees
John P. Neafsey	72	Chairman of the Board and Member of Compensation and Conflicts* Committees
John H. Robinson	61	Director and Member of Audit, Compensation* and Conflicts Committees
Wilson M. Torrence	70	Director and Member of Audit, Compensation and Conflicts Committees

* Indicates Chairman of Committee

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

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

R. Eberley Davis has been Senior Vice President, General Counsel and Secretary since February 2007. Mr. Davis also serves as Senior Vice President, General Counsel and Secretary of AGP, the general partner of AHGP. Mr. Davis has over 25 years experience in the coal and energy industries. From 2003 to February 2007, Mr. Davis practiced law in the Lexington, Kentucky office of Stoll Keenon Ogden PLLC. Prior to joining Stoll Keenon Ogden, Mr. Davis was Vice President, General Counsel and Secretary of Massey Energy Company for one year. Mr. Davis also served in various positions, including Vice President and General Counsel, for Lodestar Energy, Inc. from 1993 to 2002. Mr. Davis is an alumnus of the University of Kentucky, where he received a Bachelor of Arts degree in Economics and his Juris Doctorate degree. He also holds a Masters of Business Administration degree from the University of Kentucky. Mr. Davis is a Trustee of the Energy and Mineral Law Foundation, and a member of the American, Kentucky and Fayette County Bar Associations.

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

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

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

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

John P. Neafsey has served as Chairman of the Board of Directors since June 1996. Mr. Neafsey is also Chairman of the Conflicts Committee and a member of the Compensation Committee. Mr. Neafsey is President of JN Associates, an investment consulting firm formed in 1993. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and a Director since its founding in 1983. Positions that Mr. Neafsey held during a 23-year career at The Sun Company include Director; Executive Vice President responsible for Canadian operations, Sun Coal Company and Helios Capital Corporation; Chief Financial Officer; and other executive and director positions with numerous subsidiary companies. He is or has been active in a number of organizations, including the following: former Director and Chairman of the audit committee for The West Pharmaceutical Services Company and former Chairman and a member of the audit and compensation committees of Constar, Inc., former Chairman and member of the audit and compensation committees of NES Rentals, Inc., Trustee Emeritus and Presidential Counselor, Cornell University, and Overseer of Cornell-Weill Medical Center. Mr. Neafsey holds a Bachelor of Science degree in Engineering and a Masters of Business Administration degree from Cornell University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Neafsey should serve as a Director include his extensive service in senior corporate leadership positions in both the energy and financial services industries, and his technical expertise, knowledge and experience with financial markets.

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

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

Table of Contents

Board of Directors

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

Our Board of Directors generally administers its risk oversight function through the board as a whole. Our President and Chief Executive Officer, who reports to the Board of Directors, and the other executives named above, who report to our President and Chief Executive Officer, have day-to-day risk management responsibilities. At the Board of Director s request, each of these executives attends the meetings of our Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations and our safety performance, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, management provides a monthly report of the Partnership s financial and operational performance to each member of the Board of Directors, which often prompts questions or feedback from the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership s internal auditor, who reports directly to the Audit Committee, and reviews the Partnership s contingencies, significant transactions and subsequent events, among other matters, with management and our independent auditors.

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

Audit Committee

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

Report of the Audit Committee

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

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

118

Table of Contents

In fulfilling its oversight and other responsibilities, the Audit Committee met ten times during 2011. The Audit Committee s activities included, but were not limited to, (a) selecting the independent registered public accounting firm, (b) meeting periodically in executive session with the independent registered public accounting firm, (c) reviewing the Quarterly Reports on Form 10-Q for the three months ended March 31, June 30, and September 30, 2011, (d) performing a self-assessment of the committee, (e) reviewing the Audit Committee charter, and (f) reviewing the overall scope, plans and findings of our internal auditor. Based on the results of the annual self-assessment, the Audit Committee believes that it satisfied the requirements of its charter. The Audit Committee also reviewed and discussed with management and the independent registered public accounting firm this Annual Report on Form 10-K, including the audited financial statements.

Our independent registered public accounting firm, Ernst & Young LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with generally accepted accounting principles. The Audit Committee reviewed with Ernst & Young LLP its judgment as to the quality, not just the acceptability, of our accounting principles and such other matters as are required to be discussed with the Audit Committee under generally accepted auditing standards.

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

Based on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2011 for filing with the SEC.

Members of the Audit Committee:

Michael J. Hall, Chairman
John H. Robinson
Wilson M. Torrence

Code of Ethics

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

Communications with the Board

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

Table of Contents

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms they file. Based upon a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that during 2011 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a).

Reimbursement of Expenses of our Managing General Partner and its Affiliates

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

ITEM 11. EXECUTIVE COMPENSATION
Compensation Discussion and Analysis

Introduction

The Compensation Committee oversees the compensation of our managing general partner s executive officers, including the President and Chief Executive Officer, our principal executive officer, the Senior Vice President and Chief Financial Officer, our principal financial officer, and the three most highly compensated executive officers in 2011, each of whom is named in the Summary Compensation Table (collectively, our Named Executive Officers). Our Named Executive Officers are employees of our operating subsidiary, Alliance Coal. Certain of our Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, Alliance Coal is reimbursed for such services by those related parties pursuant to an administrative services agreement. Please see Item 13 Certain Relationships and Related Transactions, and Director Independence *Administrative Services.* We do not have employment agreements with any of our Named Executive Officers.

Compensation Objectives and Philosophy

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

Setting Executive Compensation

Role of the Compensation Committee

The Compensation Committee discharges the Board of Directors responsibilities relating to our managing general partner s executive compensation program. The Compensation Committee oversees our compensation and benefit plans and policies, administers our incentive bonus and equity participation plans, and reviews and approves annually all compensation decisions relating to our Named Executive Officers. The Compensation Committee is empowered by the Board of Directors and by the Compensation Committee s charter to make all decisions regarding compensation for our Named Executive Officers without ratification or other action by the Board of Directors. The Compensation Committee has authority to secure services for executive compensation matters, legal advice, or other expert services, both from within and outside the company. While the Compensation Committee is empowered to delegate all or a portion of its duties to a subcommittee, it has not done so.

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

Role of Executive Officers

Each year, the President and Chief Executive Officer submits recommendations to the Compensation Committee for adjustments to the salary, bonuses and long-term equity incentive awards payable to our Named Executive Officers, excluding himself. The President and Chief Executive Officer bases his recommendations on his assessment of each executive s performance, experience, demonstrated leadership, job knowledge and management skills. The Compensation Committee considers the recommendations of the President and Chief Executive Officer as one factor in making compensation decisions regarding our Named Executive Officers. Historically, and in 2011, the Compensation Committee and the President and Chief Executive Officer have been substantially aligned on decisions regarding compensation of the Named Executive Officers. As executive officers are promoted or hired during the year, the President and Chief Executive Officer makes compensation recommendations to the Compensation Committee and works closely with the Compensation Committee to ensure that all compensation arrangements for executive officers are consistent with our compensation philosophy and are approved by the Compensation Committee. At the direction of the Compensation Committee, the President and Chief Executive Officer and the Senior Vice President, General Counsel and Secretary attend certain meetings of the Compensation Committee.

Role of Compensation Consultants

The Compensation Committee engaged Mercer (US) Inc. (Mercer) as an outside compensation consultant to assist it in collecting and analyzing peer group compensation information and in assessing the competitiveness of our compensation program for 2011. Mercer took instructions from and reported to the Chairman of the Compensation Committee. Mercer reviewed published survey data and peer group proxy information, and provided a comparative analysis of competitive practices regarding base salaries, short-term incentives, total cash compensation, long-term incentives and total direct compensation.

Mercer analyzed survey sources published by Mercer and Watson Wyatt to collect compensation data for companies of similar size based on annual revenue. Mercer s peer group proxy analysis included Peabody Energy Corp, CONSOL Energy Inc., Arch Coal, Inc., Massey Energy Company, Alpha Natural Resources Inc., Patriot Coal Corp., Cloud Peak Energy, International Coal Group Inc., James River Coal Company, and Westmoreland Coal Company. This peer group was selected by Mercer and approved by the Compensation Committee. Mercer did not provide any non-executive compensation services for us or our managing general partner during 2011.

Table of Contents

Use of Peer Group Comparisons and Survey Data

The Compensation Committee believes that it is important to review and compare our performance with that of peer companies in the coal industry, and reviews the composition of the peer group annually. In setting executive compensation in 2011, the Compensation Committee reviewed the compensation information compiled by Mercer. The Compensation Committee uses the peer group and survey data as a point of reference for comparative purposes, but it is not the determinative factor for the compensation of our Named Executive Officers. The Compensation Committee exercises discretion in determining the nature and extent of the use of comparative pay data.

Consideration of Equity Ownership

Mr. Craft, the President and Chief Executive Officer, is evaluated and treated differently with respect to compensation than our other Named Executive Officers. Mr. Craft and his related entities own significant equity positions in AHGP, which owns MGP, the IDR in ARLP and, as of December 31, 2011, 42.3% of ARLP s outstanding common units. Because of these ownership positions, the interests of Mr. Craft are directly aligned with those of our unitholders. Mr. Craft has not received an increase in base salary since 2002 and has not received a bonus under our short-term incentive plan (STIP) or any grants of LTIP awards since 2005.

Compensation Components

Overview

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

- base salary;
- annual cash incentive bonus awards under the STIP; and
- awards of restricted units under the LTIP.

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

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

Base Salary

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

Annual Cash Incentive Bonus Awards

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

The performance target historically has been EBITDA-based, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the pure operating results of the core mining business. (EBITDA is defined as net income of ARLP before net interest expense, income taxes, depreciation, depletion and amortization and net income attributable to noncontrolling interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target, and it increases in relationship to our EBITDA, as adjusted, exceeding the minimum threshold. The Compensation Committee may determine satisfactory results and adjust the size of the pay-out pool in its sole discretion. In 2011, the Compensation Committee approved a minimum financial performance target of $428.6 million in EBITDA from current operations, normalized by excluding any charges for unit-based compensation and affiliate contributions, if any, and we exceeded the minimum target.

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

The performance measure for the STIP in 2012 will be EBITDA for current operations, excluding charges for unit-based compensation and affiliate contributions, if any. As discussed above, the Compensation Committee may, in its discretion, make equitable adjustments to the performance criteria under the STIP and adjust the amount of the aggregate pay-out. The Compensation Committee believes that the STIP performance criteria for 2012 will be reasonably difficult to achieve and therefore support our key compensation objectives discussed above.

Equity Awards under the LTIP

Equity compensation pursuant to the LTIP is a key component of our executive compensation program. Our LTIP is sponsored by Alliance Coal. Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. The Compensation Committee has authority to determine the participants to whom restricted units are granted, the number of restricted units to be granted to each such participant, and the conditions under which the restricted units may become vested, including the duration of any vesting period. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our managing general partner s President and Chief Executive Officer, subject to review and approval by the Compensation Committee. Grant levels are intended to support the objectives of the comprehensive compensation package described above. The LTIP grants provide our Named Executive Officers with the opportunity to achieve a meaningful ownership stake in the Partnership, thereby assuring that their interests are aligned with our success. However, as noted above, because Mr. Craft s interests are directly aligned with the interests of our unitholders as a result of his ownership positions, Mr. Craft has not been granted any awards under the LTIP since 2005. There is no formula for determining the size of awards to any individual recipient and, as it does when reviewing base salaries and individual STIP payments, the Compensation Committee considers its assessment of the individual s performance, compensation levels at peer companies in the coal industry and the recommendation of the President and Chief Executive Officer. Amounts realized from prior grants, including amounts realized due to changes in the value of our common units, are not considered in setting grant levels or other compensation for our Named Executive Officers.

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

The performance target applicable to restricted unit awards under the LTIP is based on a normalized EBITDA measure, with that measure typically being the same as the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. Historically, we have issued grants under the LTIP at the beginning of each year, with the exceptions of new employees who begin employment with us at some other time and job promotions that may occur at some other time. In 2008, we also issued grants in October in lieu of issuing grants at the beginning of 2009. The compensation expense associated with LTIP grants is recognized over the vesting period in accordance with FASB ASC 718, *Compensation Stock Compensation*.

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

The most recent grants under the LTIP, made February 6, 2012, will cliff vest on January 1, 2015 provided we achieve a target level of aggregate EBITDA for current operations, excluding charges for unit-based compensation, if any, for the period January 1, 2012 through December 31, 2014. The LTIP provides the Compensation Committee with discretion to determine the conditions for vesting (as well as all other terms and conditions) associated with any award under the plan, and to amend any of those conditions so long as an amendment does not materially reduce the benefit to the participant. The Compensation Committee believes the performance-related vesting conditions of all outstanding awards under the LTIP will be reasonably difficult to satisfy and therefore support our key compensation objectives discussed above.

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

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

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

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

Supplemental Executive Retirement Plan

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

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

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

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

(2) the participant terminates employment for good reason ;

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

(4) death of the participant;

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

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

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

Other Compensation-Related Matters

Trading in Derivatives

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

Tax Deductibility of Compensation

With respect to the deduction limitations imposed under Section 162(m) of the Internal Revenue Code, we are a limited partnership and do not meet the definition of a corporation under Section 162(m). Accordingly, such limitations do not apply to compensation paid to our Named Executive Officers.

Table of Contents

Perquisites and Personal Benefits

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

Compensation Committee Report

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

Our Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K with management. Based on our Compensation Committee s review of and the discussions with management with respect to the Compensation Discussion and Analysis, our Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

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

Members of the Compensation Committee:

John H. Robinson, Chairman
Michael J. Hall
John P. Neafsey
Wilson M. Torrence

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

Table of Contents

Summary Compensation Table for 2011

Name and Principal Position	Year	Salary (2)	Bonus (3)	Unit Awards (4)	Option Awards (1)	Non-Equity Incentive Plan Compensation (5)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (1)	All Other Compensation (6)	Total
Joseph W. Craft III,	2011	$ 334,828	$	$	$	$	$	$ 262,995	$ 597,823
	2010	334,828						288,579	623,407
President, Chief Executive Officer and Director	2009	341,267						197,634	538,901
Brian L. Cantrell,	2011	245,794		334,000		364,000		60,133	1,003,927
	2010	237,269		227,268		370,000		43,599	878,136
Senior Vice President Chief Financial Officer	2009	233,873				175,000		40,724	449,597
R. Eberley Davis	2011	272,447		334,000		370,000		75,284	1,051,731
	2010	260,473		227,268		370,000		54,920	912,661
Senior Vice President, General Counsel and Secretary	2009	254,442	70,000			185,000		56,906	566,348
Robert G. Sachse,	2011	289,968		464,260		380,000		106,735	1,240,963
	2010	283,577		350,837		390,000		84,419	1,108,833
Executive Vice President-Marketing	2009	280,148				220,000		75,349	575,497
Thomas M. Wynne,	2011	319,887		467,600		370,000		65,926	1,223,413
Senior Vice President and	2010	305,384		332,828		390,000		50,173	1,078,385
Chief Operating Officer	2009	264,807		175,988		200,000		54,387	695,182

(1) Column is not applicable.

(2) Certain of our Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, the base salary of those executive officers is reimbursed to Alliance Coal by those related parties pursuant to an administrative services agreement. Please see Item 1. Business Employees *Administrative Services Agreement*. In 2011 and 2010, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 4% for Mr. Cantrell and 8% for Mr. Davis. In 2009, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 6% for Mr. Cantrell, 8.5% for Mr. Davis, and 1% for Mr. Sachse.

(3) Amount represents a retention bonus paid to Mr. Davis in 2009.

(4) The Unit Awards represent the aggregate grant date fair value of equity awards granted (computed in accordance with FASB ASC 718) to each Named Executive Officer under the LTIP in the respective year. Please see Item 11. Compensation Discussion and Analysis Compensation Program Components *Equity Awards under the LTIP*. Messrs. Cantrell, Davis and Sachse received awards in January 2008 and October 2008. The Compensation Committee approved the awards in October 2008 in lieu of making awards in January

2009.

(5) Amounts represent the STIP bonus earned for the respective year. STIP payments are made in the first quarter of the year following the year in which they are earned. Other than this bonus, there were no other applicable bonuses earned or deferred associated with year 2011. Please see Item 11. Compensation Discussion and Analysis Compensation Program Components *Annual Cash Incentive Bonus Awards*.

127

Table of Contents

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

	Year	SERP	Profit Sharing Plan Employer Contribution	Perquisites (a)	Total
Joseph W. Craft	2011	$ 243,395	$ 19,600	$	$ 262,995
	2010	205,058	19,600	63,921	288,579
	2009	178,034	19,600		197,634
Brian L. Cantrell	2011	40,533	19,600		60,133
	2010	24,617	18,982		43,599
	2009	22,014	18,710		40,724
R. Eberley Davis	2011	55,684	19,600		75,284
	2010	35,320	19,600		54,920
	2009	37,306	19,600		56,906
Robert G. Sachse	2011	70,764	19,600	16,371	106,735
	2010	49,260	19,600	15,559	84,419
	2009	41,854	19,600	13,895	75,349
Thomas M. Wynne	2011	46,326	19,600		65,926
	2010	30,573	19,600		50,173
	2009	22,582	19,600	12,205	54,387

a) For Mr. Craft, the 2010 amount includes perquisites and other personal benefits totaling $63,921, comprising club dues of $8,621 and tax preparation fees of $55,300. For Mr. Sachse, the 2011 amount includes perquisites and other personal benefits totaling $16,371, comprising club dues of $13,091 and tax preparation fees of $3,280, the 2010 amount includes perquisites and other personal benefits totaling $15,559, comprising club dues of $6,479 and tax preparation fees of $9,080 and the 2009 amount includes perquisites and other personal benefits totaling $13,895, comprising club dues of $8,150 and tax preparation fees of $5,745. For Mr. Wynne, the 2009 amount includes perquisites and other personal benefits totaling $12,205, all of which were tax preparation fees.

Table of Contents

Grants of Plan-Based Awards Table for 2011

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Unit Awards:	All Other Option Awards: Number of Securities	Exercise or Base Price of	G Dat Va
	Grant Date	Approved Date	Threshold (8)	Target (7)	Maximum (8)	Threshold (4)	Target (2)	Maximum (4)	Number of Units (3)	Underlying Options (1)	Options Awards (1)	U Awa
W. Craft, III	February 14, 2011	(6)							726			$ 5
	May 13, 2011	(6)							722			5
	August 12, 2011	(6)							796			5
	November 14, 2011	(6)							808			5
	December 30, 2011	January 26, 2012							287			2
									3,339			24
. Cantrell	January 25, 2011	January 25, 2011					5,000					33
	February 14, 2011	(6)							35			
	May 13, 2011	(6)							35			
	August 12, 2011	(6)							38			
	November 14, 2011	(6)							39			
	December 30, 2011	January 26, 2012							395			2
		February 6, 2012		$ 364,000								
				364,000			5,000		542			37
ley Davis	January 25, 2011	January 25, 2011					5,000					33
	February 14, 2011	(6)							32			
	May 13, 2011	(6)							32			
	August 12, 2011	(6)							35			
	November 14, 2011	(6)							36			
	December 30, 2011	January 26, 2012							607			4
		February 6, 2012		370,000								
				370,000			5,000		742			38
G. Sachse	January 25, 2011	January 25, 2011					6,950					46
	February 14, 2011	(6)							47			
	May 13, 2011	(6)							47			
	August 12, 2011	(6)							52			
	November 14, 2011	(6)							52			
	December 30, 2011	January 26, 2012							746			5
		February 6, 2012		380,000								
				380,000			6,950		944			53
M. Wynne	January 25, 2011	January 25, 2011					7,000					46
	February 14, 2011	(6)							49			
	May 13, 2011	(6)							49			
	August 12, 2011	(6)							54			
	November 14, 2011	(6)							55			
	December 30, 2011	January 26, 2012							414			3

February 6, 2012	370,000			
	$ 370,000	7,000	621	$ 51

(1) Column not applicable.

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

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

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

(5) We calculated the fair value of LTIP awards using a value of $66.80 per unit, the unit price applicable for 2011 grants. We calculated the fair value of SERP phantom unit awards using the market closing price on the date the phantom unit award was granted. Phantom units granted under the SERP vest on the date granted.

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

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

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

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

Annual Cash Incentive Bonus Awards

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

Long-Term Incentive Plan

Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our managing general partner s President and Chief Executive Officer, subject to the review and approval of the Compensation Committee. Restricted units granted under the LTIP are phantom or notional units that upon vesting entitle the participant to receive an ARLP unit. Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. The performance target is based on a normalized EBITDA measure, with that measure typically being the same as the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

Table of Contents

Supplemental Executive Retirement Plan

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

Salary and Bonus in Proportion to Total Compensation

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

Name	Year	Salary and Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
Joseph W. Craft III	2011	$ 334,828	$ 597,826	56.0%
	2010	334,828	623,407	53.7%
	2009	341,267	538,901	63.3%
Brian L. Cantrell	2011	245,794	1,003,927	24.5%
	2010	237,269	878,136	27.0%
	2009	233,873	449,597	52.0%
R. Eberley Davis	2011	272,447	1,051,731	25.9%
	2010	260,473	912,661	28.5%
	2009	324,442	566,348	57.3%
Robert G. Sachse	2011	289,968	1,240,963	23.4%
	2010	283,577	1,108,833	25.6%
	2009	280,148	575,497	48.7%
Thomas M. Wynne	&n			