ALLIANCE RESOURCE PARTNERS LP
Form 10-K
February 29, 2008
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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, 2007

OR

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

COMMISSION FILE NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

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

1717 SOUTH BOULDER AVENUE, SUITE 400, TULSA, OKLAHOMA 74119

(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND ZIP CODE)

(918) 295-7600

(REGISTRANT S TELEPHONE NUMBER, INCLUDING AREA CODE)

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

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See 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 ¨

(Do not check if 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 $857,632,818 as of June 29, 2007, the last business day of the registrant s most recently completed second fiscal quarter, based on the reported closing price of the common units as reported on the NASDAQ Stock Market, LLC on such date.

As of February 25, 2008, 36,613,458 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934 and are intended to come within the safe harbor protection provided by those sections. 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 statements. Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

increased competition in coal markets and our ability to respond to the competition;

fluctuation in coal prices, which could adversely affect our operating results and cash flows;

risks associated with the expansion of our operations and properties;

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;

customer bankruptcies and/or cancellations or breaches to existing contracts;

customer delays or defaults in making payments;

fluctuations in coal demand, prices and availability due to labor and transportation costs and disruptions, equipment availability, governmental regulations and other factors;

our productivity levels and margins that we earn on our coal sales;

greater than expected increases in raw material costs;

greater than expected shortage of skilled labor;

any unanticipated increases in labor costs, adverse changes in work rules, or unexpected cash payments 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;

coal market s share of electricity generation;

prices of fuel that compete with or impact coal usage, such as oil or natural gas;

legislation, regulatory and court decisions and interpretations thereof, including but not limited to issues related to climate change;

the impact from provisions of The Energy Policy Act of 2005;

The impact from provisions of or changes in enforcement activities associated with the Mine Improvement and New Emergency Response Act of 2006 as well as any subsequent federal or state legislation or regulations;

replacement of coal reserves;

a loss or reduction of direct or indirect benefits from certain state and federal tax credits;

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

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

If one or more of these or other risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind the risk factors described in 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.

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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 SEC;
- our press releases; and
- written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

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Significant Relationships Referenced in this Annual Report

References to we, us, our or ARLP Partnership mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.

References to ARLP mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.

References to MGP mean Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., also referred to as our managing general partner.

References to SGP mean Alliance Resource GP, LLC, the special general partner of Alliance Resource Partners, L.P., also referred to as our special general partner.

References to Intermediate Partnership mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P., also referred to as our intermediate partnership.

References to Alliance Coal mean Alliance Coal, LLC, the holding company for the operations of Alliance Resource Operating Partners, L.P., also referred to as our operating subsidiary.

References to AHGP mean Alliance Holdings GP, L.P., individually as the parent company, and not on a consolidated basis.

References to AGP mean Alliance GP, LLC, the general partner of Alliance Holdings GP, L.P.

PART I

ITEM 1. BUSINESS

General

We are a diversified producer and marketer of coal primarily to major United States utilities and industrial users. We began mining operations in 1971 and, since then, have grown through acquisitions and internal development to become what we believe to be the fourth largest coal producer in the eastern United States. At December 31, 2007, we had approximately 712.8 million tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. In 2007, we produced 24.3 million tons of coal and sold 24.7 million tons of coal of which 25.9% was low-sulfur coal, 13.2% was medium-sulfur coal and 60.9% was high-sulfur coal. In 2007, approximately 93.4% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices, also known as scrubbers, to remove 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%.

At December 31, 2007, we operated eight mining complexes in Illinois, Indiana, Kentucky, Maryland, and West Virginia. Three of our mining complexes supplied coal feedstock and provided services to third-party coal synfuel facilities located at or near these complexes. The synfuel facilities ceased operations in December 2007 as the federal non-conventional source fuel tax credit expired. We also operated a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. 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 was previously owned by current and former management of the ARLP Partnership. In June 2006, our special general partner, SGP, and its parent, ARH, became wholly-owned, directly and indirectly, by Joseph W. Craft, III, the President and Chief Executive Officer of our managing general partner. SGP, a Delaware limited liability company, holds a 0.01% general partner interest in each of ARLP and the Intermediate Partnership.

We are managed by our managing general partner, MGP, a Delaware limited liability company, which holds a 0.99% and 1.0001% managing general partner interest in ARLP and the Intermediate Partnership, respectively. AHGP is a Delaware limited partnership that was formed to become the owner and 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

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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 in ARLP and 15,544,169 common units of ARLP. The following diagram depicts our organization and ownership as of December 31, 2007:

(1) The Management Group are current and former members of our management, who are the former indirect owners of MGP, and their affiliates.

(2) The units held by our special general partner and most of the units held by the Management Group are subject to a transfer restriction agreement that, subject to a number of exceptions (including certain transfers by Joseph W. Craft III 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.

Our internet address is www.arlp.com, and we make available on our internet 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 Securities and Exchange Commission. Our Code of Ethics for the chief executive officer and senior financial officers of our managing general partner is also posted on our website. Information on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

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Developing Mine Safety Laws and Regulations

In 2006, the U.S. Congress, as well as several state legislatures (including those in West Virginia, Illinois and Kentucky), passed new legislation addressing mine safety practices and imposing stringent new mine safety and accident reporting requirements and increasing civil and criminal penalties for violations of mine safety laws. In addition, the Mine Safety and Health Administration (MSHA), which monitors compliance with federal laws, published a final rule addressing mine safety equipment, training, and emergency reporting requirements and established stringent Emergency Temporary Standards for sealing off abandoned areas of underground coal mines. Pending federal legislation, if enacted, would impose additional safety and health requirements on coal mining. Although we are unable to quantify the full impact, we have experienced, and anticipate we will continue to experience, higher operating expenses and increased capital expenditures as a result of these new laws and regulations. Please read Regulation and Laws *Mine Health and Safety Laws*.

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.

Regions and Complexes	Year Ended December 31, 2007	2006	2005	2004	2003
	(tons in millions)				
Illinois Basin:					
Dotiki, Warrior, Pattiki, Hopkins and Gibson complexes	17.9	16.9	15.7	13.6	12.3
Central Appalachian:					
Pontiki and MC Mining complexes	3.2	3.5	3.3	3.6	3.6
Northern Appalachian:					
Mettiki complex	3.2	3.3	3.3	3.2	3.3
Total	24.3	23.7	22.3	20.4	19.2

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The following map shows the location of each of our mining complexes:

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. We have approximately 1,690 employees in the Illinois Basin and currently operate five mining complexes. Additionally, we hosted a coal synfuel facility at two of our mining complexes through December 2007.

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. Dotiki s preparation plant has a throughput capacity of 1,300 tons of raw coal an 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. Our primary customers for coal produced at Dotiki are Seminole Electric Cooperative, Inc. (Seminole) and Tennessee Valley Authority (TVA), both of which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units.

Warrior Complex. Our subsidiary, Warrior Coal, LLC (Warrior), operates the Cardinal mine, an underground mining complex located near the city of Madisonville in Hopkins County, Kentucky. The Warrior complex was opened in 1985 and acquired by us in February 2003. Warrior utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Warrior s preparation plant has a throughput capacity of 600 tons of raw coal an hour. Warrior s production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways. Additionally, Warrior purchased supplemental production from a third-party supplier during the first half of 2007.

In 2007, Warrior sold most of its production to Synfuel Solutions Operating, LLC (SSO) for feedstock in the production of coal synfuel. SSO s coal synfuel production facility was moved from our mining complex operated by our subsidiary, Hopkins County Coal, LLC (Hopkins County Coal), to our Warrior complex in April 2003. We had long-term agreements with SSO to host and operate its coal synfuel facility, supply the facility with coal feedstock, assist SSO with the marketing of coal synfuel and provide other services, which provided us with coal sales, rental and service fees from SSO. Certain of these services were performed by Alliance Service, Inc. (Alliance Service), a wholly-owned subsidiary of Alliance Coal. Alliance Service is subject to federal and state income taxes.

On December 31, 2007, the federal non-conventional source fuel tax credit expired. As a result, and under their terms, these long-term agreements with SSO expired on December 31, 2007. For 2007, the incremental net income benefit from the combination of the various coal synfuel-related agreements associated with the facility located at Warrior was approximately $22.4 million, assuming that coal pricing would not have increased without the availability of synfuel.

SSO shipped coal synfuel to electric utilities that have been purchasers of our coal. We maintained back-up coal supply agreements directly with these long-term customers for our coal, which automatically provided for the sale of our coal to them in the event they did not purchase coal synfuel from SSO. In 2008, our primary customer for coal produced at Warrior will be Louisville Gas and Electric Company, pursuant to a long-term coal supply agreement that was one of these back-up agreements. As such, while we will be able to sell the production that would have been sold to SSO to our back-up purchasers, we may not be able to recover the $22.4 million in incremental net income benefit of the synfuel related operations.

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. Our Pattiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour.

Coal from the Pattiki complex is shipped via the Evansville Western Railway, Inc. (EVW) railroad. Two of our primary customers for coal produced at Pattiki are Northern Indiana Public Service Company and Seminole for use in their scrubbed generating units. Pattiki production is also shipped via rail to our Mt. Vernon transloading facility for sale to utilities capable of receiving barge deliveries. In 2008, Pattiki also expects to ship a significant portion of its production to Corn Products International, Inc., Tampa Electric Company, and Vectren Corporation.

Hopkins Complex. Hopkins County Coal s mining complex, which we acquired in January 1998, is located near the city of Madisonville in Hopkins County, Kentucky. During 2006, Hopkins County Coal ceased production from its Newcoal surface mine, which is being reclaimed, and continued with the development of its Elk Creek mine in the underground reserves leased by Hopkins County Coal in 2005.

The Elk Creek mine, an underground mining complex using continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal, emerged from development in the second quarter of 2006 with production from the operation of three mining units. In November 2007, Elk Creek added a fourth production unit and is adding a fifth unit which is scheduled to be operational in the second quarter of 2008.

We are utilizing both existing and newly constructed coal handling and other surface facilities at Hopkins County Coal to process and ship coal produced from the Elk Creek mine. In conjunction with the development of the Elk Creek mine, Hopkins County Coal constructed a new preparation plant with a throughput capacity of 1,200 tons of raw coal an hour. Hopkins County Coal s Elk Creek production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways. Elk Creek has historically sold its production to a diverse group of customers and in 2008 expects TVA to be a primary customer.

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Gibson Complex. Our subsidiary, Gibson County Coal, LLC (Gibson County Coal), operates the Gibson mine, an underground mining complex located near the city of Princeton in Gibson County, Indiana. The mine began production in November 2000 and utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has a throughput capacity of 700 tons of raw coal an hour. We refer to the reserves mined at this location as the Gibson North reserves. We also control undeveloped reserves in Gibson County that are not contiguous to the reserves currently being mined, which we refer to as the Gibson South reserves.

Production from Gibson is a low-sulfur coal that historically has been primarily shipped via truck approximately 10 miles on U.S. and state highways to Gibson s principal customer, PSI Energy Inc. (d/b/a Duke Energy Indiana, Inc.), a subsidiary of Cinergy Corporation (d/b/a Duke Energy Corporation) (PSI). Gibson s production is also trucked or railed to our Mt. Vernon transloading facility for sale to utilities capable of receiving barge deliveries. In 2007, we completed construction of a new rail loop at Gibson, providing access to both the CSX and Norfolk Southern Railway Company (NS) railroads and expanding the market for coal produced at Gibson.

In January 2005, Gibson County Coal entered into long-term agreements with PC Indiana Synthetic Fuel #2, L.L.C. (PCIN) to host its coal synfuel facility, supply the facility with coal feedstock, assist PCIN with the marketing of coal synfuel and provide other services. The synfuel facility commenced operations at Gibson in May 2005. A significant portion of Gibson s production was sold to PCIN, providing us with coal sales, rental and service fees from PCIN based on the synfuel facility throughput tonnages. PCIN shipped coal synfuel to various customers that have been purchasers of our coal and with which we maintained back-up coal supply agreements, which automatically provided for the sale of our coal to them in the event they did not purchase coal synfuel from PCIN. In 2008, our primary customer for coal produced at Gibson will be PSI, pursuant to a long-term coal supply agreement that was one of these back-up agreements. On December 31, 2007, the federal non-conventional source fuel tax credit expired. As a result, and under their terms, the PCIN agreements expired on December 31, 2007. For 2007, the incremental net income benefit from the combination of the various coal synfuel related agreements associated with the facility located at Gibson was approximately $4.3 million, assuming that coal pricing would not have increased without the availability of synfuel. As such, while we will be able to sell the production that would have been sold to PCIN to PSI and other back-up purchasers, we may not be able to recover the incremental net income benefit of the synfuel related operations.

We have partially completed the permitting process for the Gibson South reserves and continue to actively evaluate its development. Capital expenditures required to develop the Gibson South reserves are estimated to be in the range of approximately $100 million to $110 million, excluding capitalized interest and capitalized mine development costs associated with net cost related to 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. Assuming sufficient sales commitments are obtained and the permitting process continues as anticipated, initial production could commence in 2010 to 2012. 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*. When the Gibson South mine reaches full production capacity, we expect annual production of approximately 2.7 million to 3.1 million tons. Definitive development commitment for Gibson South is dependent upon final approval by the board of directors of our managing general partner (Board of Directors).

River View. In April 2006, we acquired 100% of the membership interest in River View Coal, LLC (River View) from ARH. River View currently controls, through coal leases or direct ownership, approximately 117.1 million tons of proven and probable high-sulfur coal in the Kentucky No. 7, No. 9 and No. 11 coal seams underlying properties located primarily in Union County, Kentucky, as well as certain surface properties, facilities and permits. River View is in the process of updating its existing permits and evaluating the timing and manner of future development of the reserve. We expect to develop River View as an underground mining complex using continuous mining units employing room-and-pillar mining techniques, with production from the operation of four mining units and capacity to expand to up to eight mining units. In July 2007, we began construction of the slope and shaft at River View. However, definitive development commitment for River View is dependent upon final approval of the Board of Directors. Capital expenditures required to develop the River View reserves are estimated to be in the range of approximately $130 million to $160 million, excluding capitalized interest and capitalized mine development costs associated with net cost related to 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.

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Assuming sufficient sales commitments are obtained and the permitting process continues as anticipated, initial production could commence in 2009 or 2010. 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*. When the River View mine reaches its production capacity with four mining units, we expect annual production of approximately 3.1 million tons, with the ability to expand annual production to 6.4 million tons with additional mining units.

Central Appalachian Operations

Our Central Appalachian mining operations are located in eastern Kentucky. We have approximately 530 employees in Central Appalachia and operate two mining complexes producing low-sulfur coal.

Pontiki Complex. Our subsidiary, Pontiki Coal, LLC (Pontiki), owns an underground mining complex located near the city of Inez in Martin County, Kentucky. We constructed the mine in 1977. Pontiki owns the mining complex and leases the reserves, and our subsidiary, Excel Mining, LLC (Excel), conducts all mining operations. Our Pontiki operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has a throughput capacity of 900 tons of raw coal an hour. In the fourth quarter of 2005, Pontiki migrated some of its mining units from the Pond Creek seam into the Van Lear seam, and full production in the Van Lear seam was reached in the second quarter of 2006. As a result, production at Pontiki is now roughly 50% Pond Creek seam coal and 50% Van Lear seam coal. Coal produced in 2007 remained low sulfur, but because of changes in geology and production from the Van Lear seam, it no longer met 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 in large part to electric utilities located in the southeastern United States and also to industrial or stoker users throughout the eastern United States via the NS railroad or by truck via U.S. and state highways to various docks on the Big Sandy River in Kentucky.

MC Mining Complex. Our subsidiary, MC Mining, LLC (MC Mining), owns an underground mining complex located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. MC Mining owns the mining complex and leases the reserves, and Excel, an affiliate of MC Mining, conducts all mining operations. The operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour. Substantially all of the coal produced at MC Mining in 2007 met or exceeded the compliance requirements of Phase II of the CAA. Production from the mine is shipped via the CSX railroad or by truck via U.S. and state highways to various docks on the Big Sandy River. MC Mining sells its low-sulfur production primarily under short-term contracts and into the spot market.

Northern Appalachian Operations

Our Northern Appalachian mining operations are located in Maryland and West Virginia. We have approximately 230 employees and operate one mining complex 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 in the Bakerstown seam) on properties controlled by Mettiki (MD) and another of our subsidiaries, Backbone Mountain, LLC, is processed at the Mettiki complex and supplements the Mettiki (WV) production, providing blending optimization and allowing the operation to take advantage of market opportunities as they arise.

Our Mettiki (MD) preparation plant has a throughput capacity of 1,350 tons of raw coal an hour. A portion of the Mettiki (WV) production is transported to this preparation plant for processing, and then trucked to a newly constructed blending facility at the Virginia Electric and Power Company (VEPCO) Mt. Storm Power Station. The preparation plant also is served by the CSX railroad, providing the opportunity to capitalize on the metallurgical coal market.

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. Production from the Mountain View mine is transported by truck either to the Mettiki (MD) preparation plant or to the coal blending facility at the VEPCO Mt. Storm Power Station.

Production from the Mountain View mine in 2007 was primarily supplied to Mt. Storm Coal Supply, LLC (Mt. Storm) for its synfuel facility, which was located at the Mt. Storm Power Station. Our agreement to supply coal to Mt. Storm terminated at the end of 2007 in conjunction with the termination of the synfuel tax credit program. For 2007, the incremental net income benefit from this agreement was approximately $1.8 million, assuming that coal pricing would not have increased without the availability of synfuel.

Our primary customer for the medium-sulfur coal produced at Mettiki is VEPCO, which purchases the coal for use in the scrubbed generating units at its Mt. Storm Power Station in West Virginia. A seven-year agreement to supply coal to the VEPCO Mt. Storm Power Station from the Mountain View mine was negotiated and finalized in June 2005. Prior to termination of our agreement to supply coal to Mt. Storm, this agreement also served as a back-up agreement with VEPCO for the sale of our coal in the event that VEPCO did not purchase coal synfuel from Mt. Storm. As such, while we will be able to sell the production that would have been sold to Mt. Storm to VEPCO and other back-up purchasers, we may not be able to recover the $1.8 million in incremental net income benefit of the synfuel related operations.

Penn Ridge Coal. In December 2005, our subsidiary, Penn Ridge Coal, LLC (Penn Ridge), entered into a coal lease and sales agreement with affiliates of Allegheny Energy, Inc. (Allegheny), to pursue development of Allegheny s Buffalo coal reserve in Washington County, Pennsylvania. The Buffalo coal reserve lease is estimated to include approximately 56.7 million tons of proven and probable high-sulfur coal in the Pittsburgh No. 8 seam. We have initiated the permitting process for the Buffalo coal reserves and are evaluating its development. Capital expenditures required to develop the Penn Ridge reserves are estimated to be in the range of approximately $165 million to $175 million, excluding capitalized interest and capitalized mine development costs associated with net cost related to incidental production. For more information about mine development costs, please read Mine Development Cost under Item 8. Financial Statements and Supplementary Data Note 2. Summary of Significant Accounting Policies. Assuming sufficient sales commitments are obtained and the permitting process is completed, initial production could commence in 2011 to 2013. 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*. When the Penn Ridge mine reaches full production capacity, we expect annual production of up to 5.0 million tons. Definitive development commitment for Penn Ridge is dependent upon final approval of the Board of Directors.

Tunnel Ridge. Our subsidiary, Tunnel Ridge, LLC (Tunnel Ridge), controls, through a coal lease agreement with our special general partner, approximately 70.5 million tons of proven and probable high-sulfur coal in the Pittsburgh No. 8 coal seam in West Virginia and Pennsylvania. An underground mining permit was issued by the West Virginia Department of Environmental Protection on February 12, 2007, and we have submitted applications for all other permits necessary to conduct operations, which currently are under review. Capital expenditures required to develop the Tunnel Ridge reserves are estimated to be in the range of approximately $210 million to $235 million, excluding capitalized interest and capitalized mine development costs associated with net cost related to 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. Assuming sufficient sales commitments are obtained and the permitting process continues as anticipated, initial production could commence in 2009 to 2011. When the Tunnel Ridge mine reaches full production capacity, we expect annual production of up to 6.0 million tons. 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*. Definitive development commitment for Tunnel Ridge is dependent upon final approval of the Board of Directors.

Other Operations

Mt. Vernon Transfer Terminal, LLC

Our subsidiary, Mt. Vernon Transfer Terminal, LLC (Mt. Vernon), leases land and operates a coal loading terminal on the Ohio River (mile marker 827.5) 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 2007, the terminal loaded approximately 1.6 million tons for customers of Pattiki, Gibson and Elk Creek.

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Coal Brokerage

As markets allow, we buy coal from non-affiliated producers principally throughout the eastern United States, which we then resell, both directly and indirectly, primarily to utility customers. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal. Purchased coal that is delivered to our operations and commingled with our production is not classified as brokerage coal. In 2007, we did not purchase or sell any coal that was classified as brokerage coal other than coal revenues associated with the settlement agreement with ICG, LLC (ICG) described in Item 7. Management s Discussion and Analysis of Financial Conditions and Results of Operations *Operating Expenses*. .

Matrix Design Group, LLC

Our subsidiaries, Matrix Design Group, LLC and Alliance Design Group, LLC (collectively, MDG), provide a variety of mine products and services for our mining operations and to unrelated parties. We acquired this business in September 2006. MDG 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 system. In 2007, our financial results were not significantly impacted by MDG 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. Revenues from these services have historically represented less than one percent of our total revenues. In 2007, our financial results were not significantly impacted by the sale of limestone products by our affiliate, Mid-America Carbonates, LLC (MAC).

Reportable Segments

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

Coal Marketing and Sales

As is customary in the coal industry, we have entered into long-term coal supply agreements with many of our customers. These arrangements are mutually beneficial to us and our customers in that they provide greater predictability of sales volumes and sales prices. In 2007, approximately 90.2% and 89.3% of our sales tonnage and total coal sales, respectively, were sold under long-term contracts (contracts having a term of one year or greater) with maturities ranging from 2008 to 2024. Our total nominal commitment under significant long-term contracts for existing operations was approximately 100.0 million tons at December 31, 2007, and is expected to be delivered as follows: 26.8 million tons in 2008, 18.9 million tons in 2009, 15.5 million tons in 2010, and 38.8 million tons thereafter during the remaining terms of the relevant coal supply agreements. The total commitment of coal under contract is an approximate number because, in some instances, our contracts contain provisions that could cause the nominal total 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 sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal total commitment can otherwise change because of price 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 others, 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 lead to early termination of a contract. Some of the long-term contracts also

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permit the contract to be reopened for renegotiation of terms and conditions other than the 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 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 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 three largest customers in 2007 were SSO, Mt. Storm and Seminole. During 2007, we derived approximately 37.9% of our total revenues from these three customers, which individually accounted for 10.0% or more of our 2007 total revenues. For more information about these customers, please read Item 8. Financial Statements and Supplementary Data Note 20. Concentration of Credit Risk and Major Customers.

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal 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., Foundation Coal Holdings, Inc., International Coal Group, Inc., James River Coal Company, Massey Energy Company, Murray Energy, Inc., Patriot Coal Corporation 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. As the price of domestic coal increases, we may also begin to compete with companies that produce coal from one or more foreign countries.

Additionally, coal competes with other fuels such as petroleum, natural gas, hydropower and nuclear energy for steam and 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.

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 6% to 65% 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 transportation options. Typically, our customers pay the transportation costs from the mine or preparation plant to the destination, which is the standard practice in the industry. In 2007, the largest volume transporter of our coal shipments, including coal synfuel shipped by SSO, was CSX, which moved approximately 38.8% of our tonnage over its rail system. The practices of, and rates set by, the transportation company serving a particular mine or customer might 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 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;

- the 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 our 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.

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, it is extremely difficult for us and other underground coal mining companies in particular, as well as the coal industry in general to comply with all requirements at all times. None of our violations to date has had a material impact on our operations or financial condition. While it is not possible to quantify the costs of compliance with applicable federal and state laws and the 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 in certain locations.

As is typical in the coal industry, we strive to obtain mining permits within a time frame that allows us to mine reserves as planned on an uninterrupted basis. Typically, we commence actions to obtain permits between 18 and 24 months before we plan to mine a new area. In our experience, permits generally are approved within 12 to 18 months after a completed application is submitted, although regulatory authorities exercise considerable discretion in the timing and scope of permit issuance and the public has rights to engage in the permitting process, including intervention in the courts, which can cause delay. Generally, we have not experienced material difficulties in obtaining mining permits in the areas where our reserves are located. However, the permitting process for certain mining operations has extended over several years and 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.

Recently, two townships in Pennsylvania enacted ordinances that purport to prohibit all coal mining activities within the townships, invalidate mining permits issued by any state or federal government entity, and, in some instances, require divestiture of all currently held coal property interests. Some of the coal reserves of our Tunnel Ridge and Penn Ridge subsidiaries are located within these townships. We believe these ordinances violate several provisions of the United States Constitution and the Pennsylvania Constitution as well as federal and state mining laws, and we will initiate legal action seeking to have them invalidated if necessary. We believe such litigation would be successful. However, in the event it was not and these ordinances were not repealed, the ordinances would prevent mining our properties within those townships which could adversely affect our results of operation and financial condition.

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. MSHA monitors and rigorously enforces compliance with these federal laws and regulations. In addition, as part of the FMSHA, the Federal Black Lung Benefits Act (BLBA), requires payments of benefits by all businesses that conduct current mining operations to coal miners with black lung disease and to some survivors of miners who die from this disease. Most of the states where we operate also have state programs for mine safety and health regulation and enforcement. In combination, federal and state safety and health regulation in the coal mining industry is perhaps the most comprehensive and rigorous system for protection of employee safety and health affecting any segment of any industry, and this regulation has a significant effect on our operating costs. Our competitors in all of the areas in which we operate are subject to the same laws and regulations.

Mining accidents resulting in fatalities in West Virginia and Kentucky in early 2006 received national attention and prompted responses at both the national and state level, leading to increased scrutiny of industry safety practices and emergency response and evacuation procedures aimed primarily at underground coal mining operations, as well as costly new requirements for additional emergency equipment and safety structures. For example, on March 9, 2006, MSHA published new emergency rules on mine safety, which imposed new mine safety equipment, training, and emergency reporting requirements which became effective immediately upon their publication in the *Federal Register*. Building on MSHA s regulatory efforts, Congress passed the Mine Improvement and New Emergency Response Act of 2006 (MINER Act), which was signed into law on June 15, 2006. The MINER Act significantly amends the FMSHA, requiring improvements in mine safety practices, 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 published a final rule, which, among other things, revised the emergency rules to comport with the requirements of the Act. The final rule became effective on December 8, 2006. Civil penalties for regulatory violations were also increased substantially by new MSHA rules that took effect on April 23, 2007. Then, on May 22, 2007, extremely stringent Emergency Temporary Standards for sealing off abandoned areas of underground coal mines took effect, pending further study and possible modification.

At the state level, West Virginia enacted legislation in January 2006 imposing stringent new mine safety and accident reporting requirements and increasing civil and criminal penalties for violations of mine safety laws. Other states, including Illinois, Pennsylvania, and Kentucky, have either proposed or passed similar bills and resolutions addressing mine safety practices, and it is possible that additional state mine safety bills may be passed at some point in the future. Fatalities related to an August 2007 mine accident in Utah also triggered intensified regulatory scrutiny and gave momentum to pending federal legislation to impose additional safety and health requirements on coal mining. Although we are unable to quantify the full impact, implementing and complying with these new laws and regulations have and are expected to continue to have an adverse impact on our results of operation and financial position.

Black Lung Benefits Act

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.

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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. Moreover, Congress and state legislatures regularly consider various items of black lung legislation that, if enacted, could adversely affect our business, financial condition, and results of operation.

Workers Compensation

We are required to compensate employees for work-related injuries. 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 (SMCRA), establishes operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities.

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

In addition, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The Abandoned Mine Lands Tax was set to expire June 30, 2006; however, on December 20, 2006, President Bush signed into law the Tax Relief and Health Care Act of 2006, which, among other things, extended the Abandoned Mine Reclamation Fund provisions until September 30, 2021. This new law also reduced the tax for surface-mined and underground-mined coal to $0.315 per ton and $0.135 per ton, respectively, beginning in the fourth quarter 2007 through 2012. In fiscal years 2013 through 2021, the tax for surface-mined and underground-mined coal will be reduced to $0.28 per ton and $0.12 per ton, respectively. We have accrued the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. 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. Also, on February 1, 2008, the Citizens Coal Council and the Kentucky Resources Council filed a complaint in the U.S. District Court for the District of Columbia challenging the Federal Office of Surface Mining s (OSM) final rule on ownership and control, including the core definitions of control, own and transfer, assignment or sale of permit rights , adding to the uncertainty in this area. 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.

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 the posting of partial 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 bonds 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 us. In addition, bonding requirements in some states have become more onerous. For example, West Virginia s bonding system requires coal companies to post site-specific bonds in an amount up to $5,000.00 per acre and imposes a per-ton tax on mined coal, currently set at $0.07/ton, which is paid to the West Virginia Special Reclamation Fund (SRF). An environmental group is claiming the SRF is underfunded and that the OSM has an obligation under SMCRA to ensure the SRF funds are increased to cover the supposed shortfall. *See The West Virginia Highlands Conservancy, Plaintiff, v. Dirk Kempthorne, Secretary of the Department of the Interior, et al*., *Defendants, and the West Virginia Coal Association, Intervenor/Defendant*, Civil Action No. 2:00-cv-1062 (United States District Court for the Southern District of West Virginia). If the Court ultimately agrees, we could be forced to bear an increase in the tax on coal mined in West Virginia.

Air Emissions

The CAA and similar state and local laws and regulations that regulate emissions into the air, 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, 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. There have been a series of federal rulemakings focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and any additional measures required under the U.S. Environmental Protection Agency (EPA) laws and regulations will make it more costly to operate coal-fired power plants and, depending on the requirements of the implementation plan of the state in which each plant is located, could make coal a less attractive fuel alternative in the planning and building of power plants in the future. Any reduction in coal s share of power generating capacity could have a material adverse effect on our business, financial condition and results of operations.

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.

The EPA has promulgated rules, referred to as the Nitrogen Oxide SIP Call, that 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. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule (CAIR), which will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010, respectively. CAIR requires these states to achieve the required nitrogen oxide and sulfur dioxide emission reductions by requiring power plants to either participate in an EPA-administered cap-and-trade program that caps these emissions in two phases, or by meeting an individual state emissions budget through measures established by the state. Similarly, in March 2005, the EPA finalized the Clean Air Mercury Rule (CAMR), which establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. If fully implemented, CAMR would permit states to develop and manage their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances. The CAIR and CAMR rules are the subject of ongoing litigation, and on February 8, 2008, the D.C. Circuit Court of Appeals vacated the CAMR rule for further consideration by the EPA. While the future of CAIR and CAMR is uncertain, the additional costs that could be associated with the implementation of rules like these at operating coal-fired power generation facilities could render coal a less attractive fuel source.

The EPA has adopted new, more stringent national air quality standards for ozone and fine particulate matter. As a result, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. For example, in December 2004, the EPA designated specific areas in the United States as being in non-attainment regions subject to new national ambient air quality standard for fine particulate matter. In March 2007, the EPA published final rules addressing how states would implement plans to bring applicable non-attainment regions into compliance with the new air quality standard. Under the EPA s final rulemaking, states have until April 2008 to submit their implementation plans to the EPA for approval. Because coal mining operations and coal-fired electric generating facilities emit particulate matter, our mining operations and our customers could be affected when the new standards are implemented by the applicable states.

In June 2005, the EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. As part of the new rules, affected states were required to develop implementation plans by December 2007 that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. This program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas. In addition, this program may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide, and particulate matter. Demand for our coal could be affected when these new standards are implemented by the applicable states.

The Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities, including some of our customers, 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. Depending on the ultimate resolution of these cases, demand for our coal could be affected.

Carbon Dioxide Emissions

The Kyoto Protocol to the United Nations Framework Convention on Climate Change calls for developed nations to reduce their emissions of greenhouse gases to 5% below 1990 levels by 2012. Carbon dioxide, which is a major by-product of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005, for those nations that ratified the treaty.

Although the United States is not participating in the Kyoto Protocol, the current session of Congress is considering climate control legislation, including multiple bills introduced in the House and the Senate that would restrict greenhouse gas emissions. Several states have already adopted legislation, regulations and/or regulatory initiatives to reduce emissions of greenhouse gases. For instance, California recently adopted the California Global Warming Solutions Act of 2006, which requires the California Air Resources Board to achieve a 25% reduction in emissions of greenhouse gases from sources in California by 2020.

On April 2, 2007, the United States Supreme Court held in *Massachusetts v. EPA* that unless EPA affirmatively concludes that greenhouse gases are not causing climate change, the EPA must regulate greenhouse gas emissions from new automobiles under the CAA. The Supreme Court remanded the matter to the EPA for further consideration. This litigation did not directly concern the EPA s authority to regulate greenhouse gas emissions from stationary sources, such as coal mining operations or coal-fired power plants. However, the Court s decision is likely to influence another lawsuit that was filed in the U.S. Court of Appeals for the District of Columbia Circuit, involving a challenge to the EPA s decision not to regulate carbon dioxide from power plants and other stationary sources under a CAA new source performance standard rule, which specifies emissions limits for new facilities. The court remanded the question to the EPA for further consideration in light of the ruling in *Massachusetts v. EPA.* Any federal or state restrictions on emissions of greenhouse gases that may be imposed in areas of the United States in which we conduct business could adversely affect our operations and demand for our products.

The permitting of a number of proposed new coal-fired power plants has also recently been contested by environmental organizations for concerns related to greenhouse gas emissions from new plants. In October 2007, state regulators in Kansas became the first to deny an air emissions construction permit for a new coal-fired power plant based on the plant s projected emissions of carbon dioxide. State regulatory authorities in Florida and North Carolina have also rejected the construction of new coal-fired power plants based on the uncertainty surrounding the potential costs associated with greenhouse gas emissions from these plants under future laws limiting the emission of carbon dioxide. In several states, where new coal-fired power plants have been approved without limits imposed on their greenhouse gas emissions, environmental organizations have appealed the issuance of the CAA permits for these facilities to the EPA s Environmental Appeals Board (EAB). In January 2008, the EAB ruled on the Illinois petition, denying review on procedural grounds.

While higher prices for natural gas and oil, and improved efficiencies and new technologies for coal-fired electric power generation have helped to increase demand for our coal, it is possible that future 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, 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 United States. 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: one for individual permits and a more streamlined program for general permits.

Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the Corps of Engineers to streamline the process for obtaining permits under Section 404 of the CWA. The Fourth Circuit Court of Appeals issued a decision on November 23, 2005, vacating the district court decision in *Bulen* and remanding the case to the lower court for consideration of further challenge to the general permit. That challenge is still pending. A similar lawsuit, *Kentucky Riverkeeper v. Rowlette*, has been filed in federal district court in Kentucky that seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. We do not operate any mines located within the Southern District of West Virginia and currently only utilize Nationwide Permit 21 at one location in Indiana. In the event current or future litigation contesting the use of Nationwide Permit 21 is successful, we may be required to apply for individual discharge permits pursuant to Section 404 of the CWA in areas that would have otherwise utilized Nationwide Permit 21. Such a change could result in delays in obtaining required mining permits to conduct operations, which could in turn result in reduced production, cash flow, and profitability.

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On September 22, 2005, environmental groups led by the Ohio Valley Environmental Coalition filed suit in the Federal District Court for the Southern District of West Virginia challenging the Corps of Engineers authority to issue individual CWA Section 404 discharge permits for certain mountaintop mining projects. The case, styled *Ohio Valley Environmental Coalition v. United States Army Corps of Engineers*, alleges that the Corps of Engineers generally acted arbitrarily and capriciously in issuing certain Section 404 permits to operators engaged in mountaintop mining operations. By order of March 23, 2007, the Court rescinded four individual permits, ruling that the Corps of Engineers had not properly supported its findings that permitted fills would not cause significant impacts. The case has been remanded to the Corps of Engineers for further evaluation of the applications, and the Corps of Engineers could be required to conduct a more extensive Environmental Impact Statement for each permit, a process that could add substantial time to a permit decision and result in a permit denial. The decision is on appeal to the Fourth Circuit, and should be resolved sometime in 2008.

By order of June 13, 2007, the same Court issued another order declaring that discharges from valley fills into sediment ponds constructed in-stream and used to control levels of sediment and other pollutants from mine sites must themselves be permitted under the CWA and meets the same standards as the effluent discharged from these ponds. Because it is frequently impracticable to construct these ponds in locations other than an existing stream channel without moving substantial amounts of additional overburden, compliance with this order could substantially increase development costs at new mining operations in West Virginia. This order is also on appeal to the Fourth Circuit. In December 2007, a similar lawsuit has been filed against the Corps of Engineers in the federal court in the Western District of Kentucky (*Kentucky Waterways Alliance, Inc., et al. v. U.S. Army Corps of Engineers, et al.,* Civil Action No. 3:07-cv-00677) challenging a permit issued to a mining operation located in Leslie County, Kentucky. The Corps of Engineers has voluntarily suspended its consideration of the permit application in that case for agency re-evaluation, and the case is currently stayed.

Although our mining operations are not implicated in any of these particular cases, it is possible that litigation affecting the Corps of Engineers ability to issue CWA permits could adversely affect our ability to obtain permits in a timely manner and could therefore adversely affect our results of operation and financial position.

Each state is required to submit to the EPA their biennial CWA Section 303(d) lists identifying all waterbodies not meeting state specified water quality standards. For each listed waterbody, the state is required to begin developing a Total Maximum Daily Load (TMDL) to:

- determine the maximum pollutant loading the waterbody can assimilate without violating water quality standards;
- identify all current pollutant sources and loadings to that waterbody;
- calculate the pollutant loading reduction necessary to achieve water quality standards; and
- establish a means of allocating that burden among and between the point and non-point sources contributing pollutants to the waterbody.

We are currently participating in stakeholders meetings and in negotiations with various states and the EPA to establish reasonable TMDLs that will accommodate expansion of our operations. These and other regulatory developments may restrict our ability to develop new mines, or could require our customers or us to modify existing operations, the extent of which we cannot accurately or reasonably predict.

The Federal Safe Drinking Water Act (SDWA) and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal slurry, fly ash, and flue gas scrubber sludge, and by requiring permits to conduct such underground injection activities. The inability to obtain these permits could have a material impact on our ability to inject such materials into the inactive areas of some of our old underground mine workings.

In addition to establishing the underground injection control program, the SDWA also imposes regulatory requirements on owners and operators of public water systems. This regulatory program could impact our reclamation operations where subsidence or other mining-related problems require the provision of drinking water to affected adjacent homeowners. However, it is unlikely that any of our reclamation activities would fall within the definition of a public water system. While we have several drinking water supply sources for our employees and contractors that are subject to SDWA regulation, the SDWA is unlikely to have a material impact on our operations.

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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 the hazardous substances released into the environment and for damages to natural resources. 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.

In 2000, the EPA declined to impose hazardous waste regulatory controls on the disposal of some coal combustion by-products (CCB), including the practice of using CCB as mine fill. However, under pressure from environmental groups, the EPA has continued evaluating the possibility of placing additional solid waste burdens on the disposal of such materials. On March 1, 2006, the National Academy of Sciences released a report commissioned by Congress that studied CCB mine filling practices and recommended federal regulatory oversight of CCB mine filling under either SMCRA or the non-hazardous waste provisions of RCRA. As a result of this report, OSM on March 14, 2007 issued an Advanced Notice of Rule Making proposing federal regulations on CCB mine filling practices. On August 29, 2007, EPA published a Notice of Data Availability concerning information regarding the disposal of CCB in landfills and surface impoundments that has been generated since the decision in 2000. No rules on the land disposal of CCB have yet been released. Accordingly, although we believe the beneficial uses of CCB that we employ do not constitute poor environmental practices, it is not currently possible to assess how any such regulations would impact our operations or those of our customers.

Other Environmental, Health And Safety Regulation

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.

The Federal Safe Explosives Act (SEA) applies to all users of explosives. Knowing or willful violations of SEA may result in fines, imprisonment, or both. In addition, violations of SEA may result in revocation of user permits and seizure or forfeiture of explosive materials.

The costs of compliance with these requirements should not have a material adverse effect on our business, financial condition or results of operations.

Employees

To conduct our operations, we employ approximately 2,600 employees, including approximately 150 corporate employees and approximately 2,450 employees involved in active mining operations. Our work-force is entirely union-free. We believe that relations with our employees are generally good.

Administrative Services

In connection with AHGP s IPO, ARLP entered into an administrative services agreement (Administrative Services Agreement) with our managing general partner, our Intermediate Partnership, AGP, AHGP and Alliance Resource Holdings, II (ARH II). Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services for AHGP 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 of $0.3 million for the year ended December 31, 2007 from AHGP and $0.4 million for the year ended December 31, 2007 from ARH II. Please read Item 13 Certain Relationships and Related Transactions, and Director Independence *Administrative Services*.

Managing General Partner Contribution

During 2007 our managing general partner contributed 50,980 common units of AHGP, valued at approximately $1.1 million at the time of contribution, and $0.8 million of cash to us for the purpose of funding certain expenses associated with our employee compensation programs. 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 the contribution. Please read Item 13 Certain Relationships and Related Transactions, and Director Independence *Managing General Partner Contribution*.

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 conservation measures; 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;
- 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 factors, we may not have sufficient available cash to pay a specific level of cash distributions to our unitholders. Furthermore, you should be aware that 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 distributable cash flow.

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

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

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

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

As of December 31, 2007, 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 owners of our managing general partner 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. As of December 31, 2007, AHGP had no outstanding debt.

AHGP is principally dependent on the cash distributions from its general and limited partner equity interests in us to service its indebtedness. Any distribution by us to AHGP will be made only after satisfying our then-current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect that we are separate from AHGP and entities that control AHGP, our credit ratings and risk profile could be adversely affected if the ratings and risk profiles of such entities were viewed as substantially lower or more risky than ours.

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Our unitholders do not elect our managing general partner or vote on our managing general partner s officers or directors. As of December 31, 2007, AHGP owned approximately 42.5% 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, 2007, AHGP held approximately 42.5% of our outstanding units. Consequently, it will be particularly difficult 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 further 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 the distributions to unitholders.

Prior to making any distributions to our unitholders, we will reimburse our general partners and their affiliates for all expenses they have incurred on our behalf. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to the unitholders. Our managing general partner has sole discretion to determine the amount of these expenses and fees. For additional information, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Related-Party Transactions, Administrative Services, and Item 8. Financial Statements and Supplementary Data Note 18. Related-Party Transactions.

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 partner generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. Additionally, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions.

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Under certain circumstances, our unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

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

Our partnership agreement contains provisions that waive or consent to conduct by our managing general partner and its affiliates and which reduce the obligations to which our managing general partner would otherwise be held by state-law fiduciary duty standards. The following is a summary of the material restrictions contained in our partnership agreement on the fiduciary duties owed by our general partners to the limited partners. Our partnership agreement:

- permits our managing general partner to make a number of decisions in its sole discretion. This entitles our managing general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our managing general partner is entitled to make other decisions in its reasonable discretion ;
- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be fair and reasonable to us and that, in determining whether a transaction or resolution is fair and reasonable, our managing general partner may consider the interests of all parties involved, including its own. Unless our managing general partner has acted in bad faith, the action taken by our managing general partner shall not constitute a breach of its fiduciary duty; and
- provides that our general partners and our officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partners and those other persons acted in good faith.

In order to become a limited partner of our partnership, a common unitholder is required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above.

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

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

Our managing general partner s discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our managing general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to unitholders.

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

As of December 31, 2007, AHGP owned approximately 42.5% of our outstanding limited partner interests. 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.

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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

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

The prices we receive for our production depends upon factors beyond our control, including:

the supply of and demand for domestic and foreign coal;

the price and availability of alternative fuels;

weather conditions;

the proximity to, and capacity of, transportation facilities;

worldwide economic conditions;

- domestic and foreign governmental regulations and taxes; and

- the effect of worldwide energy conservation measures.

A substantial or extended decline in coal prices could materially and adversely affect us by decreasing our revenues in the event that we are not otherwise protected pursuant to the specific terms of our coal supply agreements.

A material amount of our net income and cash flow has been dependent on our ability to realize direct or indirect benefits from federal income tax credits such as non-conventional source fuel tax credits. The non-conventional source fuel tax credit expired on December 31, 2007. The loss of the benefits to us from these tax credits could negatively impact our results of operations and reduce our cash available for distributions.

In 2007, we derived a material amount of our net income under long-term synfuel-related agreements with SSO, PCIN and Mt. Storm (see discussions under Warrior Complex, Gibson Complex and Mettiki (WV) in Item 1. Business). These agreements terminated on December 31, 2007 in connection with the expiration on that date of the non-conventional synfuel tax credit. In 2007, the incremental net income benefit to us from these synfuel-related agreements was approximately $28.5 million. The elimination of synfuel tax credits and the loss of related benefits to us could negatively impact our results of operations and reduce our cash available for distributions.

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.

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We compete with other large coal producers and hundreds of small coal producers in various regions of the United States 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.

Some power plants are fueled by natural gas because of the relatively cheaper construction costs of such plants compared to coal-fired plants and because natural gas is a cleaner burning fuel. The domestic electric utility industry accounts for approximately 90% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as hydroelectric power, and environmental and other governmental regulations. 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.

From time to time conditions in the coal industry may make it more difficult for us to extend existing or enter into new long-term coal supply agreements. This could affect the stability and profitability of our operations.

A substantial decrease in the amount of coal sold by us 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 2007, we sold approximately 90.2% of our sales tonnage under contracts having a term greater than one year. We refer to these contracts 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 supply agreements 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 specified events. These events are called force majeure events. Some of these events that are specific to the coal industry include:

- our inability to deliver the quantities or qualities of coal specified;
- changes in the CAA rendering use of our coal inconsistent with the customer s pollution control strategies; and
- the occurrence of events beyond the reasonable control of the affected party, including labor disputes, mechanical malfunctions and changes in government regulations.

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 our coal as a fuel source.

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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 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. A substantial portion of our coal has a high-sulfur content, which may result in increased sulfur dioxide emissions when combusted. Accordingly, these laws and regulations may affect demand and prices for our low- and high-sulfur 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. 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, possibly further reducing demand for our coal. Please read Item 1. Business Regulation and Laws *Air Emissions* and *Carbon Dioxide Emissions*.

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 2007, we derived approximately 37.9% of our total revenues from three customers, which individually accounted for 10.0% or more of our 2007 total revenues. If we were to lose any 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 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.

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;
- 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 and flooding;

- accidental mine water discharges and other geological conditions;
- employee injuries or fatalities;
- labor-related interruptions;
- inability to acquire mining rights or permits; 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 2007, we completed our annual property and casualty insurance renewal with various insurance coverages effective as of October 1, 2007. Available capacity for underwriting property insurance continues to be limited as a result of insurance carrier losses in the mining industry. As a result, we have elected to retain a participating interest along with our insurance carriers at an average rate of approximately 14.7% in the overall $75.0 million

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commercial property program, representing 35% of the primary $30.0 million layer and 2.5% of the second layer of $20.0 million in excess of the $30.0 million primary layer. We do not participate in the third layer of $25.0 million in excess of $50.0 million. The 14.7% participation rate for this year s renewal is consistent with our prior year participation. The aggregate maximum limit in the commercial property program is $75.0 million per occurrence of which, as a result of our participation, we would be responsible for a maximum amount of $11.0 million for each occurrence, excluding a $1.5 million deductible for property damage, a 60-day waiting period for business interruption and an additional $5.0 million aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future, which as a result of our level of participation in the commercial property program, could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

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 trained coal miners has caused us to operate certain mining units without full experienced staff, which decreases our productivity and increases our costs. This shortage of trained coal miners is the result of a significant percentage of experienced coal miners reaching retirement age, combined with the difficulty of retaining existing workers in and attracting new workers to the coal industry. Thus, this shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our coal, which could adversely affect our profitability.

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. 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.

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 by us 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*.

Lawsuits filed in the federal Southern District of Western Virginia and in the federal Eastern District of Kentucky have sought to enjoin the issuance of permits pursuant to Nationwide Permit 21, which is a general permit issued by the Corps of Engineers to streamline the process for obtaining permits under Section 404 of the CWA. In the event current or future litigation contesting the use of Nationwide Permit 21 is successful, we may be required to apply for individual discharge permits pursuant to Section 404 of the CWA in areas that would have otherwise utilized Nationwide Permit 21. In addition, lawsuits filed in the federal Southern District of West Virginia and in the federal Western District of Kentucky have challenged the Corps of Engineers issuance of certain individual Section 404 permits and led to a decision on March 23, 2007, by the U.S. District Court for the Southern District of West Virginia rescinding the permits in question based on a finding that the Corps of Engineers issued the permits in violation of the CWA and National Environmental Policy Act. This decision is currently on appeal to the U.S. Court of Appeals for the Fourth Circuit. Although our mining operations are not implicated in any of these particular cases, it is possible that this ruling may have long-term effects on the Corps of Engineers ability to issue CWA permits and could thereby adversely affect our results of operation and financial position. Such a change could result in delays in obtaining required mining permits to conduct operations, which could in turn result in reduced production, cash flow and profitability. Please read Item 1. Business Regulations and Laws *Water Discharge*.

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

Some of our mines depend on a single transportation carrier or a single mode of transportation. Disruption of any of these 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.

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.

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

Since our formation and the acquisition of our predecessor in August 1999, we have expanded our 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. If we are unable to successfully integrate the companies, businesses or properties we acquire through such expansion, 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.

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

Historically, a portion of our growth and operating results have been from acquisitions. 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.

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 our reserves decline 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 capable of being mined 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.

Our business depends, in part, upon our ability to find, develop or acquire additional coal reserves that we can recover economically. Our existing reserves will decline as they are depleted. Our planned development projects and acquisition activities may not increase our reserves significantly and we may not have continued success expanding existing and developing additional mines. We believe that there are substantial reserves on certain adjacent or neighboring properties that are unleased and otherwise available. However, we may not be able to negotiate leases with the landowners on acceptable terms. An inability to expand our operations into adjacent or neighboring reserves under this strategy could have a material adverse effect on our business, financial condition or results of operations.

The estimates of our coal reserves may prove inaccurate, and you should not place undue reliance on these estimates.

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 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. As a result, you should not place undue reliance on the coal reserve data included herein.

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

The geological characteristics of some of our coal 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 capable of being mined 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.

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

Our coal mining operations continue to be 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 have risen significantly in recent years, and historically, the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel have fluctuated. In 2007, we continued to experience increases in the cost of materials and supplies, particularly consumables such as steel, copper and power. There may be acts of nature or terrorist attacks or threats that could also increase the future costs of raw materials. If the price of steel, petroleum products or other raw materials increase, our operational expenses will increase and could have a significant negative impact on 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 8.31% senior unsecured notes and our revolving credit facility. At December 31, 2007, our total indebtedness outstanding was $154.0 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, it fails to meet a coverage test based on the ratio of our consolidated debt to our consolidated cash flow.

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

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

Federal and state laws require us to place and maintain bonds to secure our obligations to repair and return property to its approximate original state after it has been mined (often referred to as reclaim or reclamation), to pay federal and state workers compensation and pneumoconiosis, or black lung, benefits and to satisfy other miscellaneous obligations. These bonds provide assurance that we will perform our statutorily required obligations and are referred to

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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 third-parties for reclamation expenses, federal and state workers compensation obligations and other miscellaneous obligations. We may have difficulty maintaining our surety bonds for mine reclamation as well as workers compensation and black lung benefits. Our inability to acquire or failure to maintain these bonds would have a material adverse effect on us.

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 joint and several 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 (or judicial interpretations or more stringent enforcement of existing laws and regulations) may be adopted or that judicial interpretations or more stringent enforcement of existing laws and regulations may occur, in the future that could materially affect our mining operations, cash flow, and profitability, either through direct impacts such as new requirements impacting our existing mining operations, or indirect impacts such as new laws and regulations that discourage or limit our customers use of coal.

As a result of recent mining accidents that caused fatalities in West Virginia and Kentucky, Congress and several state legislatures (including those in West Virginia, Illinois and Kentucky) have passed new laws addressing mine safety practices and imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. Implementing and complying with these new 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*.

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 the applicable company 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.

Tax Risks to Our Common Unitholders

If we were to become subject to entity-level taxation for federal or 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 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 (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because taxes would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in our anticipated cash flow and after-tax return to you, likely causing a substantial reduction in the value of our units.

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. At the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. 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 any state were to impose a tax upon us or as an entity, the cash available for distribution to you would be reduced.

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 different than expected.

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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 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 individual retirement accounts 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 United States 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. If the IRS were to challenge this 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 tangible assets and a lesser portion allocated to our intangible 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.

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 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. 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 (and our unitholders could receive two Schedules K-1) 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 fiscal year ending December 31, 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.

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.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Coal Reserves

We must obtain permits from applicable state 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, 2007, we had approximately 712.8 million tons of coal reserves. All of the estimates of reserves which are presented in this Annual Report on Form 10-K are of proven and probable reserves (as defined below) and adhere to the standards described in 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, 2007, about each of our mining operations:

			Proven and Probable Reserves Pounds $S0_2$ per MMbtu (tons in millions)				Reserve Assignment	
Operations	**Mine Type**	**Heat Content (Btus per pound)**	**<1.2**	**1.2-2.5**	**>2.5**	**Total**	**Assigned**	**Unassigned**
Illinois Basin Operations								
Dotiki (KY)	Underground	12,300			125.6	125.6	125.6	
Warrior (KY)	Underground	12,350			57.4	57.4	24.4	33.0
Hopkins (KY)	Underground	12,300			47.1	47.1	32.0	15.1
	/Surface	11,500			7.8	7.8	7.8	
River View (KY)	Underground	11,700			117.1	117.1	117.1	
Pattiki (IL)	Underground	11,800			54.5	54.5	54.5	
Gibson (North) (IN)	Underground	11,600		25.3	4.0	29.3	29.3	
Gibson (South) (IN)	Underground	11,600		18.5	64.1	82.6		82.6
Region Total				43.8	477.6	521.4	390.7	130.7
Central Appalachian Operations								
Pontiki (KY)	Underground	12,800		14.9		14.9	14.9	
MC Mining (KY)	Underground	12,800	18.0		1.8	19.8	19.8	
Region Total			18.0	14.9	1.8	34.7	34.7	
Northern Appalachian Operations								
Mettiki (MD)	Underground	13,000		2.8	7.4	10.2	10.2	
Mountain View (WV)	Underground	13,000		5.1	14.2	19.3	19.3	
Tunnel Ridge (PA/WV)	Underground	12,600			70.5	70.5	70.5	
Penn Ridge (PA)	Underground	12,500			56.7	56.7	56.7	
Region Total				7.9	148.8	156.7	156.7	
Total			18.0	66.6	628.2	712.8	582.1	130.7
% of Total			2.5%	9.4%	88.1%	100.0%	81.7%	18.3%

Our reserve estimates are prepared from geological data assembled and analyzed by our staff of geologists and engineers. This data is obtained through our extensive, ongoing exploration drilling and in-mine channel sampling programs. Our drill spacing criteria adhere to standards as defined by the U.S. Geological Survey. 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.

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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 overview audit of our reserves and calculation methods in October 2005.

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 the coal being produced at the small contour strip operation at our Mettiki (MD) complex, which has metallurgical qualities. The 18.0 million tons of reserves listed as <1.2 pounds of SO_2 per 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.

Btu values are reported on an as-shipped, fully washed basis. Shipments that are either fully or partially raw will have a lower Btu value.

We control certain leases for coal deposits that are near, but not contiguous to, our primary reserve bases. The tons controlled by these leases are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits are as follows: Dotiki 15.6 million tons, Pattiki 4.9 million tons, Hopkins County Coal 1.8 million tons, River View 24.7 million tons, Gibson (North) 1.4 million tons, Gibson (South) 11.1 million tons, Warrior 3.0 million tons, Tunnel Ridge 7.0 million tons, Penn Ridge 3.4 million tons and Pontiki 0.2 million tons.

We lease most of our reserves and generally have the right to maintain leases in force until the exhaustion of the mineable and merchantable coal within the leased premises or for so long as we are conducting mining operations in a larger defined 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.

Acquisition of Illinois Basin Coal Reserves. In June 2007, our subsidiary, Alliance Resource Properties, LLC (Alliance Resource Properties), acquired from a subsidiary of Consol Energy, Inc. the rights to approximately 78.4 million tons of high-sulfur coal reserves encompassing approximately 13,500 acres located in Webster and Hopkins Counties, Kentucky. As a result of the purchase, we gained control of approximately 78.4 million tons of coal in the Kentucky No. 9, No. 11 and No. 13 coal seams, along with related surface properties. Additionally, as a result of this transaction, we reclassified 8.4 million tons of high-sulfur non-reserve coal deposits as reserves, increasing our reserves at the time by approximately 14%.

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Mining Operations

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

Operations	Location	Tons Produced 2007	2006	2005	Transportation	Equipment
		(tons in millions)				
Illinois Basin Operations						
Dotiki	Kentucky	4.6	4.7	4.7	CSX, PAL, truck	CM
Warrior	Kentucky	4.6	4.5	4.1	CSX, PAL, truck	CM
Hopkins	Kentucky	2.6	1.6	0.9	CSX, PAL, truck	DL, CM
Pattiki	Illinois	2.9	2.5	2.6	EVW, barge	CM
Gibson (North)	Indiana	3.2	3.6	3.4	CSX, NS, truck, barge	CM
Region Total		17.9	16.9	15.7		
Central Appalachian Operations						
Pontiki	Kentucky	1.4	1.6	1.7	NS, truck, barge	CM
MC Mining	Kentucky	1.8	1.9	1.6	CSX, truck, barge	CM
Region Total		3.2	3.5	3.3		
Northern Appalachian Operations						
Mettiki	Maryland	0.4	2.8	3.3	Truck, CSX	LW, CM, CS
Mountain View	West Virginia	2.8	0.5		Truck, CSX	LW, CM
Region Total		3.2	3.3	3.3		
TOTAL		24.3	23.7	22.3		

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

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 (*e.g.*, relating to, among other things, coal quality, quantity, pricing and the existence of force majeure conditions) 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 19. Commitments and Contingencies is incorporated herein by this reference.

On April 24, 2006, we were served with a complaint from Mr. Ned Comer, et al., who we refer to as the plaintiffs, alleging that approximately 40 oil and coal companies, including us, which we refer to as the defendants, are liable to the plaintiffs for tortiously causing damage to plaintiffs property in Mississippi. The plaintiffs allege that the defendants greenhouse gas emissions caused global warming and resulted in the increase in the destructive capacity of Hurricane Katrina. On August 30, 2007, the court dismissed the plaintiffs complaint. On September 17, 2007, plaintiffs filed a notice of appeal of that dismissal to the United States Court of Appeals for the Fifth Circuit and their appeal is pending. We believe this complaint is without merit and we do not believe that an adverse decision in this litigation matter, if any, will have a material adverse effect on our business, financial position or results of operations.

On June 15, 2006, Mettiki (MD) was issued a Notice of Violation by the Maryland Department of Environment (MDE) for alleged exceedances of permitted sulfur dioxide emissions. These alleged exceedances occurred between May 23, 2006 and June 12, 2006, at the Mettiki (MD) Thermal Coal Dryer associated with the longwall mining operation, located in Garrett County, Maryland. This self-reported violation was promptly corrected and Mettiki (MD) demonstrated to the satisfaction of MDE that it is in compliance with MDE regulations. On July 18, 2007, a consent decree was filed by the MDE which required Mettiki (MD) to pay a penalty assessment of $150,000. The assessment has been paid.

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ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITIES HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER 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 25, 2008, the closing market price for the common units was $39.37 per unit. As of February 25, 2008, there were 36,613,458 common units outstanding. There were approximately 23,399 record holders and beneficial owners (held in street name) of common units at December 31, 2007.

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 2006	$ 40.70	$ 33.68	$0.460 (paid May 15, 2006)
2nd Quarter 2006	$ 43.79	$ 34.00	$0.500 (paid August 14, 2006)
3rd Quarter 2006	$ 39.00	$ 33.84	$0.500 (paid November 14, 2006)
4th Quarter 2006	$ 37.45	$ 33.59	$0.540 (paid February 14, 2007)
1st Quarter 2007	$ 38.00	$ 33.40	$0.540 (paid May 15, 2007)
2nd Quarter 2007	$ 45.50	$ 37.50	$0.560 (paid August 14, 2007)
3rd Quarter 2007	$ 44.40	$ 30.12	$0.560 (paid November 14, 2007)
4th Quarter 2007	$ 41.08	$ 33.00	$0.585 (paid February 14, 2008)

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 the minimum quarterly distribution (MQD) and 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 MQD and the target distribution levels. Our partnership agreement defines the MQD as $0.25 for each full fiscal quarter.

Under the quarterly incentive distribution provisions of the partnership agreement, our managing general partner is entitled to receive 15% of the amount we distribute in excess of $0.275 per unit, 25% of the amount we distribute in excess of $0.3125 per unit, and 50% of the amount we distribute in excess of $0.375 per unit.

Equity Compensation Plans

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

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ITEM 6. SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2007, 2006, 2005, 2004 and 2003.

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

	Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
Statements of Income					
Sales and operating revenues:					
Coal sales	$ 960.3	$ 895.8	$ 768.9	$ 599.4	$ 501.6
Transportation revenues	37.7	39.9	39.1	29.8	19.5
Other sales and operating revenues	35.3	31.9	30.7	24.1	21.6
Total revenues	1,033.3	967.6	838.7	653.3	542.7
Expenses:					
Operating expenses	685.1	627.8	521.5	436.4	368.8
Transportation expenses	37.7	39.9	39.1	29.8	19.5
Outside purchases	22.0	19.2	15.1	9.9	8.5
General and administrative	34.4	30.9	33.5	45.4	28.3
Depreciation, depletion and amortization	85.3	66.5	55.6	53.7	52.5
Net gain from insurance settlement (1)	(11.5)			(15.2)	
Total operating expenses	853.0	784.3	664.8	560.0	477.6
Income from operations	180.3	183.3	173.9	93.3	65.1
Interest expense (net of interest capitalized)	(11.7)	(12.2)	(14.6)	(15.8)	(16.3)
Interest income	1.7	3.0	2.8	0.8	0.3
Other income	1.4	0.9	0.6	1.0	1.4
Income before income taxes, cumulative effect of accounting change and minority interest	171.7	175.0	162.7	79.3	50.5
Income tax expense	1.6	2.4	2.7	2.7	2.6
Income before cumulative effect of accounting change and minority interest	170.1	172.6	160.0	76.6	47.9
Cumulative effect of accounting change (2)		0.1			
Minority interest	0.3	0.2			
Net income	$ 170.4	$ 172.9	$ 160.0	$ 76.6	$ 47.9
General Partners interest in net income	$ 31.3	$ 24.6	$ 12.4	$ 3.3	$ 0.3
Limited Partners interest in net income	$ 139.1	$ 148.3	$ 147.6	$ 73.3	$ 47.6
Basic net income per limited partner unit	$ 3.07	$ 3.06	$ 2.89	$ 1.76	$ 1.30
Diluted net income per limited partner unit	$ 3.05	$ 3.03	$ 2.84	$ 1.71	$ 1.26
Weighted average number of units outstanding-basic	36,548,150	36,425,350	36,288,527	35,881,896	35,161,468
Weighted average number of units outstanding-diluted	36,800,212	36,810,383	36,977,061	36,874,336	36,325,678

Balance Sheet Data:					
Working capital	$ 25.9	$ 37.4	$ 76.1	$ 54.2	$ 16.4
Total assets	701.7	635.0	532.7	412.8	336.5
Long-term obligations (3)	137.1	127.5	144.0	162.0	180.0
Total liabilities	384.5	386.5	376.9	357.6	323.9
Partners capital	317.2	248.5	155.8	55.2	12.6
Other Operating Data:					
Tons sold	24.7	24.4	22.8	20.8	19.5
Tons produced	24.3	23.7	22.3	20.4	19.2
Revenues per ton sold (4)	$ 40.31	$ 38.02	$ 35.07	$ 29.98	$ 26.83
Cost per ton sold (5)	$ 30.02	$ 27.78	$ 25.00	$ 23.64	$ 20.80
Other Financial Data:					
Net cash provided by operating activities	$ 244.0	$ 250.9	$ 193.6	$ 145.1	$ 110.3
Net cash used in investing activities	(178.7)	(137.7)	(110.2)	(77.6)	(77.8)
Net cash used in financing activities	(101.0)	(108.5)	(82.6)	(46.4)	(31.3)
EBITDA (6)	267.0	250.8	230.1	147.9	119.0
Maintenance capital expenditures (7)	76.3	67.8	56.7	31.6	30.0

(1) Represents the net gain from the final settlement with our insurance underwriters for claims relating to the MC Mining Mine Fire in 2007 (Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations MC Mining Mine Fire) and the Dotiki Mine Fire Incident in 2004.

(2) Represents the cumulative effect of the accounting change attributable to the adoption of Statement of Financial Accounting Standards (SFAS) No. 123R, *Share-Based Payments*, on January 1, 2006.

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

(4) Revenues per ton sold are based on the total of coal sales and other sales and operating revenues divided by tons sold.

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

(6) EBITDA is defined as income before income taxes, cumulative effect of accounting change, minority 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 as 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 generally accepted accounting principles. 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 (i.e. public reporting versus computation under financing agreements).

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

	Year Ended December 31,				
	2007	2006	2005	2004	2003
Cash flows provided by operating activities	$ 244,012	$ 250,923	$ 193,618	$ 145,055	$ 110,312
Non-cash compensation expense	(3,925)	(4,112)	(8,193)	(20,320)	(7,687)
Asset retirement obligations	(2,419)	(2,101)	(1,918)	(1,622)	(1,341)
Coal inventory adjustment to market	(21)	(319)	(573)	(488)	(687)
Net gain (loss) on sale of property, plant and equipment	3,189	1,188	(179)	332	885
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 damaged vertical belt equipment			(1,298)		
Other	(811)	(1,119)	(580)	(587)	(532)
Net effect of working capital changes	7,898	(5,317)	34,770	7,915	(553)
Interest expense, net	9,952	9,175	11,816	14,963	15,981
Income taxes	1,669	2,443	2,682	2,641	2,577