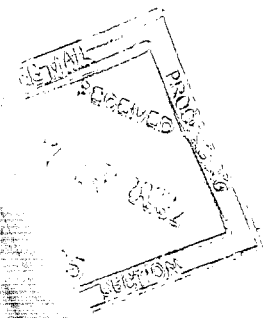



# POWERING AMERICA



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**ALLIANCE RESOURCE  
PARTNERS, L.P.**

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## Message from the President and Chief Executive Officer

### Dear Fellow Unitholders:

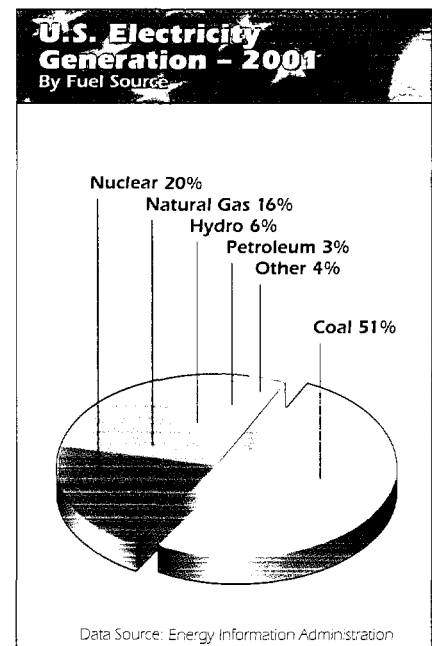
In our short history as a publicly-traded master limited partnership, the year 2001 was our best year ever. During 2001, the movement in coal prices was the most dramatic we have seen in decades. After a cold winter in early 2001 and with reduced utility coal inventories, the coal industry experienced increases in prices in excess of 50%. At the same time, the coal industry responded by increasing production in order to capture these higher prices. This increase in production, coupled with one of the warmest periods for November and December on record and a general economic slowdown for the United States, caused prices to quickly fall. Although the current price environment remains above the year 2000 level, today's current coal prices are far below the peak achieved in early 2001.

With the majority of the Partnership's production committed under long-term contracts, we are somewhat insulated from these price swings. However, we were able to benefit from higher revenues on limited spot coal sales made last year, which led the way for the Partnership achieving record financial results in 2001. Year-to-year price appreciation in our unit trading value of 50% during 2001, was slightly more than the nearly 50% appreciation achieved during calendar year 2000. When adding in the quarterly cash distributions paid to our unitholders in 2001, the total return on the Partnership's common and subordinated units was nearly 65% in 2001, compared to nearly 70% in the year 2000. As a result of the coal price volatility experienced in 2001, we expect that our total revenues in 2002 will be higher yet.

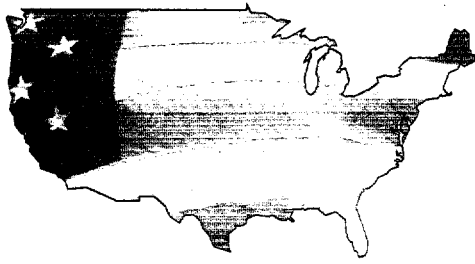
The year 2001 will be most remembered, however, by the tragic events occurring on September 11, 2001. The impact of that day will be felt by all Americans through the balance of our lifetimes. As the months have passed since that day, it is still difficult to believe what we saw and read countless times in the media. With the loss of human life, both here and abroad, many Americans, who lost loved ones, friends, and associates, have an empty space in their hearts and lives. Contrary to what might have been the outcome of this assault on the American spirit, this tragic event has become a rallying point from which we can continue to build our businesses, leading to a stronger and more resilient economy.

As America and its economy recovers, the need for low-cost, reliable sources of energy has become even more important. Affordable electricity is vital to the economic growth of the United States. Not only is coal the most abundant natural resource in America, but coal is also the nation's lowest cost fuel source for electricity generation. Because of this, coal has continued to maintain its historical dominance as the primary fuel for electricity generation with over a 50% market share in 2001. With rebuilding the nation's economic strength a priority, the Partnership's coal will continue to be there to fill its primary role in the energy chain – Powering America.

The tragic events of September 11 have focused our thoughts on what it means to be an American. The Partnership's employees realize the critical role we have in providing the lowest cost fuel source for electricity generation in America. Coal is the energy source that literally fuels the economic engine that moves America forward. On behalf of our employees, I want to thank you, the Partnership's unitholders, for your support of, and investment in, the Alliance Resource organization.

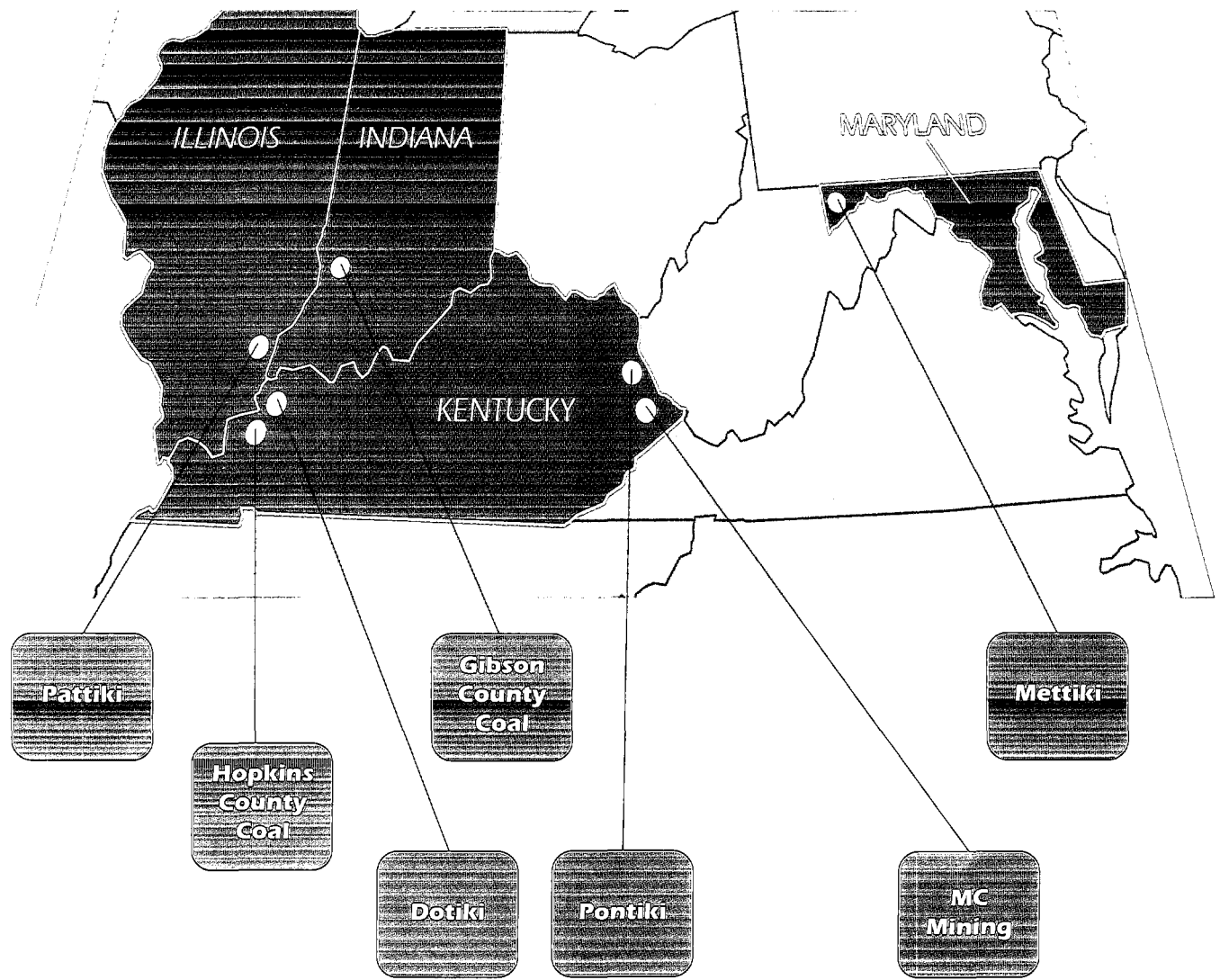


**Joseph W. Craft III**  
President and Chief Executive Officer



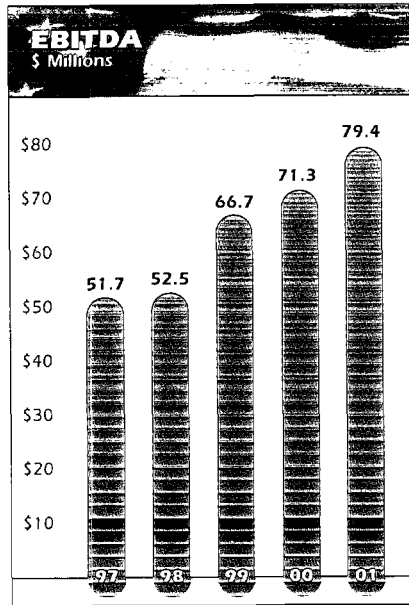
# Alliance Resource Partners, L.P. Operations Overview

The Partnership is a diversified producer and marketer of coal to major United States utilities and industrial users. Since we began mining operations in 1971, the Partnership has grown through acquisitions and internal development to become one of the largest coal producers in the eastern United States.



# To the Unitholders of Alliance Resource Partners, L.P.

Despite volatile coal prices and difficult geologic conditions at several of our mining complexes, the overall strength of our operations allowed the Partnership to have its most successful year, reporting both record EBITDA and net income in 2001.



## Financial Highlights

For the year ended December 31, 2001, the Partnership reported record net income of \$17.1 million, or \$1.09 per basic limited partner unit, compared to net income of \$15.6 million, or \$0.99 per basic limited partner unit, for 2000. Revenues were \$446.3 million and coal sales were 17.0 million tons for 2001, compared to \$363.5 million and 15.0 million tons for 2000. EBITDA (income before net interest expense, income taxes, depreciation, depletion and amortization) for 2001 was a record \$79.4 million compared to \$71.3 million in 2000. The comparative financial results include the cumulative effect of an accounting change of \$7.9 million in 2001 and unusual items of \$9.5 million in 2000. Excluding the net benefits of the change in accounting method in 2001 and the unusual items previously reported in 2000, EBITDA for 2001 was a record \$71.4 million, compared to \$61.8 million for 2000, and net income was a record \$9.2 million, or \$0.58 per basic limited

partner unit, compared to \$6.1 million, or \$0.39 per basic limited partner unit for 2000.

The Partnership produced 15.7 million tons in 2001, a nearly 15% increase from 2000. The production increase was primarily attributable to the inclusion of a full year of production from our new Gibson County Coal mining complex, which opened in November 2000. Total revenues of \$446.3 million for 2001 represented an increase of approximately 23% from the 2000 level. Higher sales prices and volumes reflecting increased utility demand, increased activity in the domestic coal brokerage market, and additional revenues from our new Gibson County Coal operation resulted in increased sales for the Partnership.

During 2001, various mining operations encountered adverse mining conditions that increased the Partnership's overall mining cost per ton. The Gibson County Coal start-up schedule was negatively impacted by poor roof and other unexpected geological conditions reducing its productivity. Our Mettiki operation also experienced challenging geological conditions. The Partnership experienced unanticipated equipment failures causing higher maintenance costs at other operations, as well. The Partnership has taken action to address these operating issues and to control future expenses. The Gibson County mine plan was revised and has shown consistent improvements in productivity since early December 2001. Mettiki has completed mining in a difficult longwall panel of its reserve base and has moved into reserves with more favorable mining conditions. The Partnership has also invested in replacement mining equipment that is better suited to existing mining conditions. Even with the year's challenging operating issues, the Partnership still achieved record financial results. With the steps taken in 2001 to improve operating reliability, the Partnership should be positioned to achieve improved productivity and reduced cost levels in the future.

During 2001, the Partnership changed its method of estimating black lung

benefits to the service cost method in order to better match its costs over the service lives of the miners, who ultimately receive these benefits. Consequently, the change in accounting is presented as a cumulative effect of accounting change in the 2001 consolidated financial statements. The net benefit of the accounting change resulted in an increase in net income of \$7.9 million. The service cost method is the predominant method used in the coal industry to estimate black lung benefit liabilities.

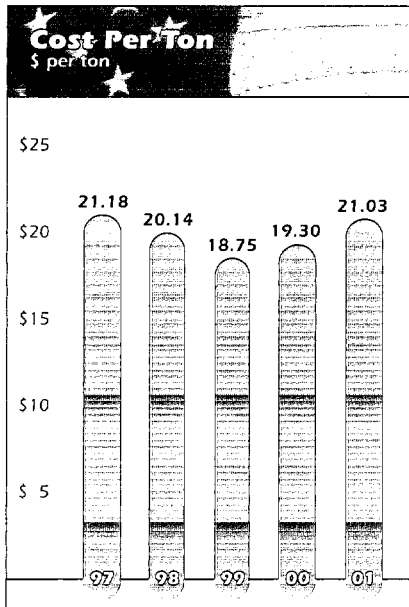
## Long-Term Contracts

We have entered into long-term contracts with many of our customers that contribute to both the Partnership's and our customers' financial stability by providing greater predictability of sales volumes and prices. In 2001, approximately 78% of our sales tonnage, accounting for 75% of our total revenue, was sold under long-term contracts with maturities ranging from 2001 to 2012. Our total nominal commitment under significant long-term contracts was approximately 85 million tons at December 31, 2001. Major electric utilities are the primary source of our long-term contracts. The Partnership has recently entered into long-term agreements to supply coal feedstock and other services to a coal synfuel facility located at our Hopkins County mine through December 2007. Additionally, replacement coal supply agreements with each coal synfuel customer have been put in place that automatically provide for the sale of our coal directly to the customer in the event they do not receive coal synfuel. The Partnership's strategy of maintaining a significant long-term contract position has historically provided us with less volatility during active market cycles.

## Coal Reserves

The Partnership continues to maintain an adequate coal reserve base to preserve its continuity over the long term. At December 31, 2001, we had proven and probable reserves of approximately 400 million tons to support future production. We are constantly evaluating reserve additions

that are adjacent or complementary to our current operations in order to replenish our produced tonnage. In 2001, the Partnership renewed an option from an affiliate of its Special General Partner to lease approximately 25 million tons of coal reserves located in western Kentucky that would further increase its reserve base. These reserves, owned by an affiliate of the Special General Partner, are not included in the Partnership's reserve totals noted above.



### Warrior Coal Option

In early 2001, the Partnership's Special General Partner, through affiliates acquired the operating assets of Warrior Coal in western Kentucky near the Partnership's Hopkins County Coal mining complex. In accordance with a right of first refusal provision provided in the Omnibus Agreement between the Partnership and its Special General Partner, the Partnership approved the acquisition of Warrior Coal by its Special General Partner, subject to future purchase rights granted to the Partnership for these assets. The Partnership and an affiliate of its Special General Partner have entered into an option agreement that, if exercised by either party, would allow the transfer of the Warrior Coal operating assets to the Partnership as early as 2003. Exercise of the option is

subject to certain conditions, including compliance with certain covenants and the absence of any material adverse change. Warrior Coal is currently undergoing expansion efforts through 2002 that may increase its productive capacity to more than 2.5 million tons per year. A final determination by either party concerning the potential exercise of the option is not expected until the second half of 2002 or early 2003.

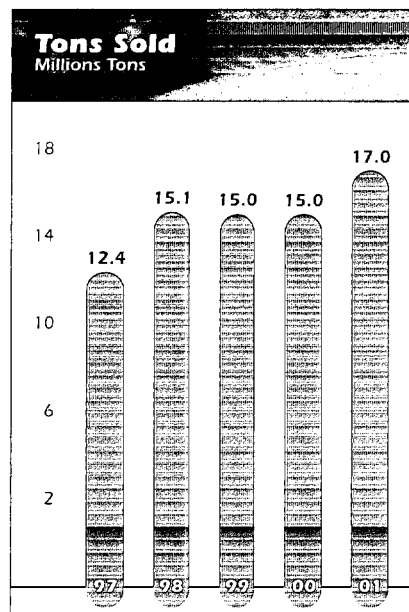
### Distributions to Unitholders

During 2001, the Partnership made quarterly cash distributions to its unitholders of \$0.50 per unit, an annualized rate of \$2.00 per unit. Distributions were declared and paid on all of the Partnership's outstanding common and subordinated units. The Partnership's distributions to unitholders are generally not taxable to the extent of the unitholder's tax basis. However, each unitholder is allocated a share of income, gains, losses and deductions. The majority of the distributions are not subject to current income taxes, resulting in a significant enhancement of the after-tax yield on the Partnership's units.

### Future Prospects

The Partnership continues to evaluate growth opportunities that will augment its distributable cash flow. Because of the Partnership's diverse asset base, our focus on growth is not limited to only competitive acquisition auctions of other coal operating companies. We also have opportunities within our existing operations that can be developed with the possibility for significant returns on investment.

As the Partnership's Pattiki mining complex in southern Illinois continued to approach the boundary of its existing reserve base, movement into adjacent reserves became necessary in order for its long-term production to continue. In 2000, the Partnership approved the mine extension of Pattiki and capital expenditures of \$30 million during the 2000-2003 time period. When completed, we expect Pattiki to be positioned to maintain, and possibly grow, its existing production level for the next decade.



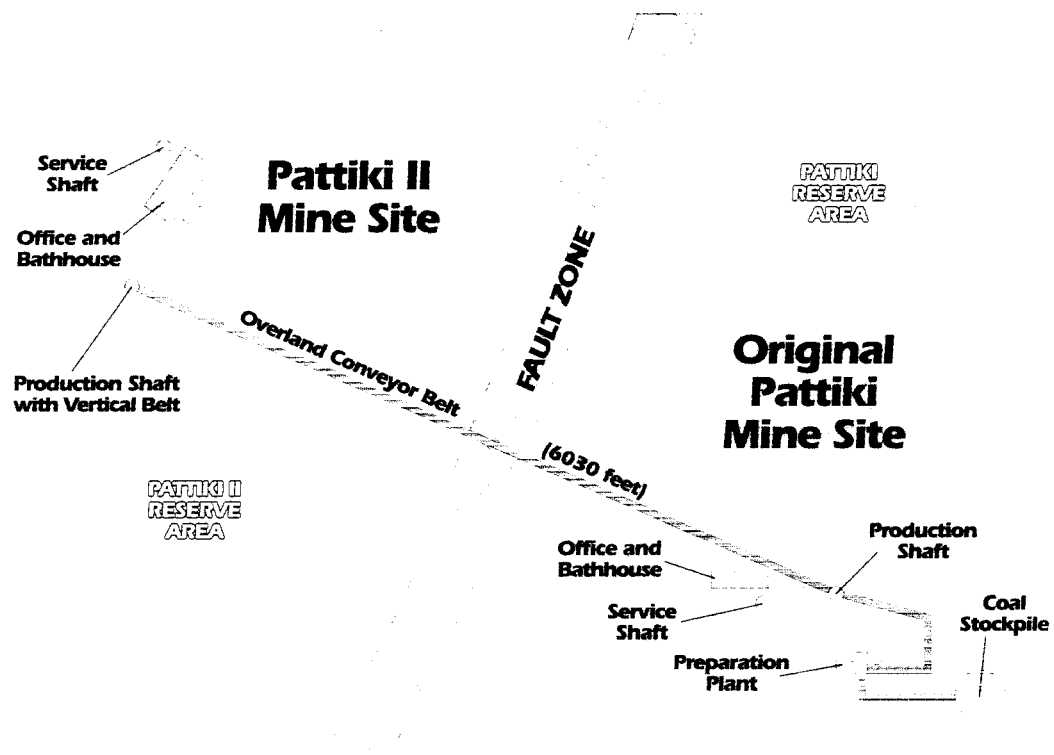
The Partnership also has the opportunity at several of its other existing operations to increase productive capacity at low incremental cost. With available infrastructure in place, we have the ability to introduce additional mining units to existing operations. The timing of this additional capacity is dependent upon market demand for this added coal supply. Increasing coal supply during weak demand periods is a negative economic event for not only the increased capacity, but the existing production capacity as well. The Partnership seeks opportunities to increase its capacity where coal demand dictates the need for additional supply.

Through the previously mentioned option agreement with an affiliate of the Special General Partner involving the Warrior Coal assets, the Partnership also has a near-term opportunity to grow via acquisition. The option to transfer the operating assets of Warrior Coal is at a predetermined price and can be exercised, subject to certain conditions, beginning in 2003. If the option is exercised, due to Warrior Coal's proximity to our existing operations, the Partnership should be able to take advantage of favorable operating and marketing synergies between our Dotiki and Hopkins County Coal operations and Warrior Coal.

## **Pattiki II - Extending Our Future**

The Partnership's Pattiki mining complex has been producing coal in southern Illinois since the early 1980s. During its long history, Pattiki's ample reserve base has allowed it to produce over 30 million tons of coal for sale to the electric utility industry. After operating for nearly 20 years, Pattiki has mined substantially all of its current coal reserves that are mineable using its existing mine infrastructure. To maintain our distributable cash flow, the Partnership approved in 2000 the development of Pattiki II in order to gain access to adjacent coal reserves through new mine infrastructure.

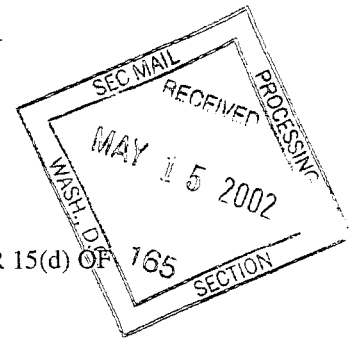
**Capital Infrastructure** To support the extension into the Pattiki II coal reserve area, during 2000 the Partnership approved capital expenditures of approximately \$30 million to be invested over the 2000 to 2003 time period. Developing the second mine requires the construction of a new production shaft to extract mined coal, and a new service shaft to provide miners and supplies access to the underground production areas. A vertical belt will also be installed to transport the coal from the mine to the surface. From the new production shaft, the coal will be hauled via a newly constructed overland conveyor belt for processing at Pattiki's existing coal preparation plant. As part of the capital plan for Pattiki II, mining equipment will also be upgraded to enhance production capabilities.



**Transition Timing** In light of the construction schedule for development of the Pattiki II mine, and in order to ensure uninterrupted production, a transition from the original Pattiki mine to the new Pattiki II mine is required. Groundbreaking for the extension occurred in October 2000 and construction of the mine shafts began immediately. The construction has remained on schedule and production from the new Pattiki II mine is expected to begin in the fourth quarter of 2002. As the reserves are depleted from the original Pattiki mine coal reserve area, mining units and employees from the existing Pattiki mine will be moved to the new Pattiki II mine. The transition to the new Pattiki II mine is expected to be completed during the second quarter of 2003.

**Project Benefits** The Partnership will gain numerous benefits from the Pattiki mine extension. The coal reserves associated with Pattiki II have a greater average thickness than those being mined today, which should increase productivity and lower costs. Initially, productivity should also be enhanced by the new service shaft that will reduce miners' travel time to their equipment, thereby increasing productive capacity. When completed, we expect the Pattiki II mining complex to be positioned to maintain its existing production level for the next decade, as well as to provide available capacity to easily expand production when market conditions are favorable. The extension to Pattiki II is an excellent example of utilizing a successful workforce and existing infrastructure to extend the Partnership's future.

UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549



## FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2001

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  
(STATE OR OTHER JURISDICTION OF  
INCORPORATION OR ORGANIZATION)

73-1564280  
(IRS EMPLOYER IDENTIFICATION NO.)

1717 SOUTH BOULDER AVENUE, SUITE 600, 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: None

Securities registered pursuant to Section 12(g) of the Act: common units representing limited partner interests

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. 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.

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 \$178,670,542 on March 28, 2002, based on \$24.18 per unit, the closing price of the common units as reported on the Nasdaq National Market on such date.

As of March 28, 2002, 8,982,780 common units and 6,422,531 subordinated units are 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 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. These statements are based on our beliefs as well as assumptions made by, and information currently available to, us. When used in this document, the words “anticipate,” “believe,” “continue,” “estimate,” “expect,” “forecast,” “may,” “project,” “will,” and similar expressions identify forward-looking statements. These statements reflect our current views with respect to future events and are subject to various risks, uncertainties and assumptions. Specific factors which could cause actual results to differ from those in the forward-looking statements, include:

- competition in coal markets and our ability to respond to the competition;
- fluctuation in coal price, which could adversely affect our operating results and cash flows;
- deregulation of the electric utility industry and/or the effects of any adverse change in the domestic coal industry, electric utility industry, or general economic conditions;
- dependence on significant customer contracts, including renewing customer contracts upon expiration;
- customer cancellations of, or breaches to, existing contracts;
- customer delays or defaults in making payments;
- fluctuations in coal demand, price 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;
- any unanticipated increases in labor costs, adverse changes in work rules, or unexpected cash payments associated with post-mine reclamation and workers' compensation claims;
- greater than expected environmental regulation, costs and liabilities;
- a variety of operational, geologic, permitting, labor and weather-related factors;
- risk of major mine-related accidents or interruptions; and
- results of litigation.

If one or more of these 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” above. The risk factors could also cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments

You should consider the above information 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
- oral statements made by us or any of our officers or other persons acting on our behalf.

## PART I

### ITEM 1. BUSINESS

#### General

We are a diversified producer and marketer of coal 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 the eighth largest coal producer in the eastern United States. At December 31, 2001, we had approximately 400.7 million tons of reserves in Illinois, Indiana, Kentucky, Maryland and West Virginia. In 2001, we produced 15.7 million tons of coal and sold 17.0 million tons of coal. The coal we produced in 2001 was 28.7% low-sulfur coal, 17.2% medium-sulfur coal and 54.1% high-sulfur coal. In 2001, approximately 91% 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%.

We currently operate seven mining complexes in Illinois, Indiana, Kentucky and Maryland. Six of our mining complexes are underground and one has multiple surface operations and a single underground mine. Our mining activities are organized into three operating regions: (a) the Illinois Basin operations, (b) the East Kentucky operations, and (c) the Maryland operations.

We and our subsidiary, Alliance Resource Operating Partners, L.P. (referred to as the intermediate partnership), were formed to acquire, own and operate substantially all of the coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation formerly known as Alliance Coal Corporation. We completed our initial public offering on August 20, 1999, at which time Alliance Resource Holdings contributed substantially all of its operating assets and liabilities to the intermediate partnership.

Our managing general partner, Alliance Resource Management GP, LLC, and our special general partner, Alliance Resource GP, LLC (collectively referred to as our general partners) own an aggregate 2% general partner interests in us. Our limited partners, including the general partners as holders of common units and subordinated units, own an aggregate 98% of the limited partner interests in us.

The coal production and marketing assets of Alliance Resource Holdings acquired by us are referred to as our "predecessor." All 1999 operating data contained herein includes our results and our predecessor's results.

#### 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 production by region for the last five years.

<u>Operating Region and Mines</u>	<u>2001</u>	<u>2000</u>	<u>1999</u>	<u>1998</u>	<u>1997</u>
			(tons in millions)		
Illinois Basin Operations:					
Dotiki, Pattiki, Hopkins County, Gibson County	10.2	8.4	8.5	7.9	5.2
East Kentucky Operations:					
Pontiki, MC Mining	2.8	2.7	2.8	2.5	2.8
Maryland Operations:					
Mettiki	<u>2.7</u>	<u>2.6</u>	<u>2.8</u>	<u>3.0</u>	<u>2.9</u>
Total	<u>15.7</u>	<u>13.7</u>	<u>14.1</u>	<u>13.4</u>	<u>10.9</u>

### *Illinois Basin Operations*

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. We have approximately 975 employees in the Illinois Basin and currently operate four mining complexes.

*Webster County Coal, LLC.* Webster County Coal operates the Dotiki mine, which is an underground mining complex, located near Providence, Kentucky in Webster and Hopkins Counties, Kentucky. The mine was opened in 1966, and we purchased the mine in 1971. Our Dotiki operation utilizes continuous mining units employing room-and-pillar mining techniques. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour.

Production from the mine is shipped via the CSX railroad, the Paducah & Louisville railroad and by truck on U.S. and state highways. Our primary customers for coal produced at Dotiki are Seminole Electric Cooperative, Inc. (Seminole), Tennessee Valley Authority (TVA) and Western Kentucky Energy Corp. (WKE), which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units. During August 2001, Dotiki began construction of a new mine shaft and ancillary facilities, which is expected to be operational in late 2002 and will provide a new access for miners and supplies.

*White County Coal, LLC.* White County Coal operates the Pattiki mine, which is an underground mining complex, located near New Harmony, Indiana in White County, Illinois. We began construction of the mine in 1980 and have operated it since its inception. Our Pattiki operation utilizes continuous mining units employing room-and-pillar mining techniques. We are in the process of extending our Pattiki mine into adjacent coal reserves, which will include two new shafts and ancillary facilities. This extension involves capital expenditures of approximately \$30 million during the 2000-2003 period and allows the Pattiki mining complex to continue and expand its existing productive capacity for the next 15 years. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour.

Production from the mine is shipped via the CSX railroad. Our primary customers for coal produced at Pattiki are Seminole and Cincinnati Gas & Electric Company, which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units.

*Hopkins County Coal, LLC.* Hopkins County Coal is a mining complex located near Madisonville, Kentucky in Hopkins County, Kentucky. We acquired Hopkins County Coal in January 1998, and consistent with our acquisition plans, purchased new mining equipment and completed extensive equipment rebuilds during 1998. The operation has three surface mines, one of which is currently idle, and one underground mine. The surface operations utilize dragline mining, and the underground operation utilizes a continuous mining unit employing room-and-pillar mining techniques. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour.

Production from the complex is shipped via the CSX and the Paducah & Louisville railroads and by truck on U.S. and state highways. Our primary customers for coal produced at Hopkins County Coal have been Louisville Gas & Electric Company (LG&E), TVA and WKE, which have purchased our coal pursuant to long-term contracts for use in their scrubbed generating units. As discussed under "Other Operations; Coal Synfuel" below, we now sell most of Hopkins County Coal's production to the synfuel facility owner, which in turn sells coal synfuel to LG&E, TVA and other potential customers. We have put in place "back-up" coal supply agreements with these customers, which automatically provide for sale of our coal to them in the event they do not receive coal synfuel.

*Gibson County Coal, LLC.* Gibson County Coal is an underground mining complex located near Princeton, Indiana in Gibson County, Indiana. In October 1999, we announced the award of engineering and construction contracts for the development of dual mine slopes and a mine shaft to support mining operations. Subsequent contracts were awarded by our special general partner for the construction of a coal preparation plant and handling facilities, providing us access to these facilities under a long-term operating lease agreement. The mine began production with a single mining unit in November 2000. The Gibson County mining complex utilizes multiple continuous mining units employing room-and-pillar mining techniques. The preparation plant has a throughput capacity of 700 tons of raw coal an hour.

Production from Gibson County Coal is a low-sulfur coal, shipped via truck approximately 10 miles on U.S. and state highways to our primary customer, PSI Energy Inc. (PSI), a subsidiary of Cinergy Corporation. In 1997, we acquired an additional 99.9 million tons of undeveloped recoverable reserves in Gibson County, which are not contiguous to the reserves currently being mined. We refer to these reserves as the Gibson County "South" reserves.

#### *East Kentucky Operations*

Our East Kentucky mining operations are located in the Central Appalachia coal fields. Our East Kentucky mines produce low-sulfur coal. We have approximately 435 employees and operate two mining complexes in East Kentucky.

*Pontiki Coal, LLC.* Pontiki is an underground mining complex located near Inez, Kentucky in Martin County, Kentucky. We constructed the mine in 1977. Pontiki owns the mining complex and reserves and Excel Mining LLC, an affiliate of Pontiki, is responsible for conducting all mining operations. Substantially all of the coal produced at Pontiki meets or exceeds the compliance requirements of Phase II of the Clean Air Act amendments. Our Pontiki operation utilizes continuous mining units employing room-and-pillar mining techniques. The preparation plant has a throughput capacity of 800 tons of raw coal an hour.

Production from the mine is shipped via the Norfolk Southern railroad or by truck via U.S. and state highways to various docks on the Big Sandy River in Kentucky. Our primary customers for coal produced at Pontiki are James River Cogeneration Company, the successor to Cogentrix of Virginia, Inc., and AEI Coal Sales Company, Inc.

*MC Mining, LLC.* MC Mining is an underground mining complex located near Pikeville, Kentucky in Pike County, Kentucky. MC Mining was acquired in 1989. When we began operations in late 1996, MC Mining was operated by an unaffiliated contract mining company. During 2000, the contract mining agreement was terminated and MC Mining entered into an intercompany support services agreement with Excel Mining. Selected employees of the contractor and other qualified individuals were hired by Excel Mining, which is responsible for conducting all mining operations. The operation utilizes continuous mining units employing room-and-pillar mining techniques. The preparation plant has a throughput capacity of 800 tons of raw coal an hour.

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 in the spot market.

#### *Maryland Operations*

Our Maryland mining operation is located in the Northern Appalachia coal fields. We have approximately 235 employees and operate one mining complex in Maryland.

*Mettiki Coal, LLC.* Mettiki is an underground longwall mining complex located near Oakland, Maryland in Garrett County, Maryland. We constructed Mettiki in 1977 and have operated it since its inception. The operation utilizes a longwall miner for the majority of the coal extraction as well as continuous mining units used to prepare the mine for future longwall mining. The preparation plant has a throughput capacity of 1,350 tons of raw coal an hour.

Our primary customer for coal produced at Mettiki is Virginia Electric and Power Company (VEPCO), which purchases the coal pursuant to a long-term contract for use in the generating units at its Mt. Storm, West Virginia power plant, located less than 20 miles away. Our coal is trucked to Mt. Storm over a private haul road, which links to a state highway. Mettiki is also served by the CSX railroad. We also process coal at Mettiki for Anker Energy Corporation and one of its affiliates.

*Mettiki Coal (WV), LLC.* Mettiki (WV) has approximately 15.8 million tons of undeveloped recoverable reserves in Grant and Tucker Counties, West Virginia adjacent to Mettiki in Garrett County, Maryland. We currently conduct no mining operations at Mettiki (WV).

### Other Operations

#### *Mt. Vernon Transfer Terminal, LLC*

The Mt. Vernon terminal is a rail-to-barge loading terminal on the Ohio River in Mt. Vernon, Indiana. The terminal has a capacity of 5.5 million tons per year with existing ground storage. The terminal was used from 1983 through 1998 for shipments from Pattiki and Dotiki under our coal supply agreement with Seminole. Seminole now transports these shipments to its generating units directly by CSX railroad. We recently entered into coal supply agreements that are intended to ship approximately 1.4 million tons through the Mt. Vernon terminal in 2002.

#### *Coal Synfuel*

We recently entered into long-term agreements with Synfuel Solutions Operating LLC (SSO) to host and operate its coal synfuel facility at Hopkins County Coal, supply coal feedstock, assist with the coal synfuel marketing and provide other services through December 31, 2007. These agreements provide us with coal sales and service fees from SSO based on the synfuel facility throughput tonnage, which amounts are dependent on the ability of the facility's owners to use certain qualifying tax credits applicable to the facility. A portion of these services will be performed by a newly formed subsidiary, Alliance Service, Inc., which is subject to federal and state income tax. As discussed above in "Mining Operations; Illinois Basin; Hopkins County Coal", we now sell most of the coal produced at our Hopkins County Coal mining complex to SSO, while Alliance Coal Sales, an unincorporated sales business unit of Alliance Coal, assists SSO with the sale of its coal synfuel to our customers pursuant to a sales agency agreement. The term of each of these agreements is subject to early cancellation provisions customary for transactions of these types, including the unavailability of synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. Therefore, the continuation of the operating revenues associated with the coal synfuel production facility cannot be assured. However, we have put in place "back up" coal supply agreements with each coal synfuel customer, which automatically provide for sale of our coal to them in the event they do not receive coal synfuel.

#### *Coal Brokerage*

We buy coal from outside producers throughout the eastern United States, which we then resell, both directly and indirectly, to utility and industrial customers. We purchased and sold approximately 535,000 tons

of outside coal in 2001. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal.

### *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.

### *Coal Marketing And Sales*

As is customary in the coal industry, we have entered into long-term contracts with many of our customers. These arrangements are mutually beneficial. Our utility customers secure a fuel supply for their power plants for years into the future. Our long-term contracts contribute to both our customers' and our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2001, approximately 78% of our sales tonnage, accounting for 75% of our total revenue, was sold under long-term contracts (contracts having a term of greater than one year) with maturities ranging from 2001 to 2012. Our total nominal commitment under significant long-term contracts was approximately 84.6 million tons at December 31, 2001 and is expected to be delivered as follows: 15.4 million tons in 2002, 12.6 million tons in 2003, 11.9 million tons in 2004 and 11.6 million tons in 2005 and 2006, and 21.5 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 production capacity. In addition, the nominal total commitment can otherwise change because of price reopener provisions contained in certain of these long-term contracts. We believe our long-term contract position compares favorably to those of our competitors.

The terms of long-term contracts are the results of both bidding procedures and extensive negotiations with the customer. As a result, the terms 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 permit the contract to be reopened to renegotiate 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 2001 were Seminole, TVA and VEPCO. Sales to these customers in the aggregate accounted for approximately 41% of our 2001 total revenues, and sales to each of these customers

accounted for more than 10% of our 2001 total revenues. Each of these customers has purchased coal regularly from us for more than 15 years. In addition, under the agreements we have entered into with SSO to supply coal feedstock and other services, we now sell most of the coal produced at our Hopkins County Coal facility to SSO. SSO, through Alliance Coal Sales, acting as its agent, in turn sells coal synfuel to our former customers at Hopkins County Coal, including TVA. As a result, in 2002 it is likely that our coal sales to SSO will account for more than 10% of our revenues, while our sales to TVA will no longer account for more than 10% of our revenues.

On February 28, 2002, a major customer of our Pontiki mine (not one of the three major customers discussed above) voluntarily filed for Chapter 11 bankruptcy protection. Accompanying the bankruptcy filing was a pre-packaged plan of reorganization unanimously approved by certain creditor classes. The customer has represented in its bankruptcy filing and public press releases that all existing trade claims will be paid in full and a vast majority of its contracts will be continued without any adverse impact. All of the accounts receivable under the long-term contract with this customer are current. Management does not anticipate that this event will have a material impact on our financial condition or results of operations.

### Competition

The United States coal industry is highly competitive with numerous producers in all coal producing regions. We compete with other large producers and hundreds of small producers in the United States. The largest coal company is estimated to have sold approximately 15% of the total 2001 tonnage sold in the United States market. We compete with other coal producers primarily on the basis of coal price at the mine, coal quality (including sulfur content), transportation cost from the mine to the customer, and the reliability of supply. Continued demand for our coal and the prices that we obtain are also affected by demand for electricity, environmental and government regulations, technological developments, and the availability and price of alternative fuel supplies, including nuclear, natural gas, oil, and hydroelectric power.

### 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 10% to 80% of the 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.

Customers pay the transportation costs from the contractual F.O.B. point (free-on-board point), which is consistent with practice in the industry and is generally from the mine to the customer's plant. In 2001, the largest volume transporter of our coal production was the CSX railroad, which moved approximately 50% of our tonnage over its rail system. The practices of, and rates set by, the railroad serving a particular mine or customer might affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mine. At our Gibson and Mettiki mines, a contractor operates a truck delivery system that transports the coal from the mine to the primary customer's power plant.

### 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 pollution;

- storage of petroleum products and substances which are regarded as hazardous under applicable laws or which, if spilled, could reach waterways or wetlands;
- storage and handling of explosives;
- plant and wildlife protection;
- reclamation and restoration of mining properties after mining is completed;
- the discharge of materials into the environment;
- management of solid wastes generated by mining operations;
- protection of wetlands;
- management of electrical equipment containing polychlorinated biphenyls (PCBs);
- surface subsidence from underground mining;
- the effects (if any) that mining has on groundwater quality and availability; and
- legislatively mandated benefits for current and retired coal miners.

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. The possibility exists that new legislation or regulations, or new interpretations of existing laws or regulations, may be adopted that may have a significant impact on our mining operations or our customers' ability to use coal, or may require us or our customers to change our or their operations significantly or to incur substantial costs.

We are committed to conducting mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding our compliance efforts, we do not believe these violations can be eliminated completely. None of the violations to date or the monetary penalties assessed at our operations have been material.

While it is not possible to quantify the costs of compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. Capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value estimated cost of reclamation and mine closing, including the cost of treating mine water discharge, when necessary. The accrual for reclamation and mine closing costs is based upon permit requirements and the costs and timing of reclamation 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. Compliance with these laws has substantially increased the cost of coal mining for all domestic coal producers.

#### *Mining Permits and Approvals*

Numerous governmental permits or approvals are required for mining operations. We may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. All requirements imposed by any of these authorities may be costly and time-consuming, and may delay commencement or continuation of mining operations. Future legislation and administrative regulations may emphasize more heavily the protection of the environment and, as a consequence, our activities may be more closely regulated. Legislation and regulations, as well as future interpretations of existing laws, may require substantial increases in equipment and operating costs, or delays, interruptions or termination of operations, the extent of any of which cannot be predicted.

Before commencing mining on a particular property, we must obtain mining permits and approvals by state regulatory authorities of a reclamation plan for restoring, upon the completion of mining, the mined property to its approximate prior condition, productive use or other permitted condition. 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 months after a completed application is submitted. We have not experienced material or significant difficulties in obtaining mining permits in the areas where our reserves are currently located. However, we cannot assure you that we will not experience difficulty in obtaining mining permits in the future.

On January 29, 2002, the West Virginia Department of Environmental Protection (West Virginia DEP) denied a permit application for the mining of approximately 3.1 million tons of Mettiki (WV)'s non-reserve coal deposits. Mettiki planned to mine the tons covered by the denied permit from its existing underground infrastructure because this portion of Mettiki (WV)'s non-reserve coal deposits are contiguous to Mettiki's reserves located in Maryland. We have appealed the permit denial by the West Virginia DEP to the West Virginia Surface Mining Board and hearings have been scheduled during May 2002.

Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws. 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 which have outstanding environmental violations. Although we have been cited for violations in the ordinary course of our business, we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

#### *Mine Health and Safety Laws*

Stringent safety and health standards have been imposed by federal legislation since 1969 when the Coal Mine Health and Safety Act of 1969 (CMHSA) was adopted. CMHSA resulted in increased operating costs and reduced productivity. The Federal Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of CMHSA, imposes comprehensive safety and health standards on all mining operations. Regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. The Mine Safety and Health Administration monitors compliance with these federal laws and regulations. In addition, as part of CMHSA and the Mine Safety and Health Act of 1977, the Black Lung Benefits Act requires payments of benefits by all businesses that conduct current mining operations to a coal miner with black lung disease and to some survivors of a miner who dies 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. Even the most minute aspects of mine operations, particularly underground mine operations, are subject to extensive regulation. This regulation has a significant effect on our operating costs. For example, new regulations governing exposures to diesel particulate matter in underground mines will likely increase our compliance costs in 2002. However, our competitors in all of the areas in which we operate are subject to the same laws and regulations.

#### *Black Lung Benefits Act (BLBA)*

The Federal 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 will be 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 against potential cost using actuarially determined estimates of the cost of present and future claims. We are also liable under state statutes for black lung claims.

The U.S. Department of Labor published revised regulations in December 2000, that became effective in January 2001, that will alter the claims process for federal black lung benefit recipients, which among other things:

- simplify administrative procedures for the adjudication of claims;
- propose preference for the miner's treating physician under certain circumstances;
- allow previously denied claims to be refiled and litigated under a different standard;
- limit the amount of evidence all parties may submit for consideration;
- create a rebuttable presumption that medical treatment for any pulmonary condition is caused or aggravated by the miner's work; and
- expand the definition of pneumoconiosis and total disability.

Because the revised regulations are expected to result in an increase in the incidence and recovery of black lung claims, both the coal and insurance industries are currently challenging certain provisions of the revised regulations through litigation. A federal judge upheld these regulations in August 2001. An appeal was filed in August 2001. In addition, Congress and state legislatures regularly consider various items of black lung legislation, which, if enacted, could adversely affect our business financial condition and results of operations.

#### *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.

#### *Coal Industry Retiree Health Benefits Act (CIRHBA)*

The Federal CIRHBA was enacted to provide for the funding of health benefits for some United Mine Workers of America retirees. The act 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. The act 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, LLC. However, in connection with the sale of the coal assets acquired by Alliance Resource Holdings in 1996, MAPCO Inc. agreed to retain, and be responsible for, all liabilities under CIRHBA.

#### *Surface Mining Control and Reclamation Act (SMCRA)*

The Federal SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. The act requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities. In conjunction with mining the property, we reclaim and restore the mined areas by grading, shaping and preparing the soil for seeding. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for a variety of uses, as specified in the approved reclamation plan. We believe that we are in compliance in all material respects with applicable regulations relating to reclamation.

SMCRA and similar state statutes, require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. The act requires us to restore the surface

to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. The mine operator must submit a bond or otherwise secure the performance of these reclamation obligations. The earliest a reclamation bond can be released is five years after reclamation has been achieved. 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 occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. 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 maximum tax is \$0.35 per ton on surface-mined coal and \$0.15 per ton on underground-mined coal. We have accrued for 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 of orphaned mine sites and acid mine drainage control on a statewide basis.

Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent contract mine operators and other third parties can be imputed to other companies which 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 revocation of any permits that have been issued since the time of the violations or, in the case of civil penalties and reclamation fees, since the time their amounts became due. We are not aware of any currently pending or asserted claims against us relating to the "ownership" or "control" theories discussed above. However, we cannot assure you that such claims will not develop in the future.

#### *Clean Air Act (CAA)*

The Federal CAA and similar state laws, which regulate emissions into the air, affect coal mining and processing operations primarily through permitting and emissions control requirements. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. For example, the CAA requires reduction of sulfur dioxide (SO<sub>2</sub>) emissions from electric power generation plants in two phases. Only some facilities were subject to the Phase I requirements. Beginning in year 2000, Phase II requires nearly all facilities to reduce emissions. The effected utilities are able to meet these requirements by:

- switching to lower sulfur fuels;
- installing pollution control devices such as scrubbers;
- reducing electricity generating levels; or
- purchasing or trading so-called pollution "credits."

Specific emissions sources receive these "credits" that utilities and industrial concerns can trade or sell to allow other units to emit higher levels of SO<sub>2</sub>. In addition, the CAA requires a study of utility power plant emissions of some toxic substances and their eventual regulation, if warranted. The effect of the CAA cannot be completely ascertained at this time, although the SO<sub>2</sub> emissions reduction requirement is projected generally to increase the demand for lower sulfur coal and potentially decrease demand for higher sulfur coal.

The CAA also indirectly affects coal mining operations by requiring utilities that currently are major sources of nitrogen oxides (NO<sub>x</sub>) in moderate or higher ozone nonattainment areas to install reasonably available control technology for NO<sub>x</sub>, which are precursors of ozone. In October 1998, the U.S. Environmental Protection Agency (EPA) issued a rule requiring 22 eastern states and the District of Columbia to make substantial reductions in NO<sub>x</sub> emissions by the year 2003, which was substantially upheld by the U.S. Court of Appeals for the D.C. Circuit on March 3, 2000. On March 5, 2001, the U.S. Supreme Court declined to review that decision, in response to a petition by seven states and the power and coal industries. This deadline was recently extended by EPA to 2004. EPA expects that affected states will achieve

reductions by requiring power plants to make substantial reductions in their NOx emissions. This in turn will require power plants to install reasonably available control technology and additional control measures. Installation of reasonably available control technology and additional measures required under EPA regulations will make it more costly to operate coal-fired plants and, depending on the requirements of individual state implementation plans and the development of revised new source performance standards, could make coal a less attractive fuel alternative in the planning and building of utility power plants in the future. Any reduction in coal's share of the capacity for power generation could have a material adverse effect on our business, financial condition and results of operations. The effect these regulations, or other requirements that may be imposed in the future, could have on the coal industry in general and on our business in particular cannot be predicted with certainty. We cannot assure you that the implementation of the CAA, the new National Ambient Air Quality Standards (NAAQS) discussed below, or any other current or future regulatory provision, will not materially adversely affect us.

In addition, EPA has already issued and is considering further regulations relating to fugitive dust and emissions of other coal-related pollutants such as mercury, nickel, dioxin and fine particulates. For example, in July 1997 EPA adopted new, more stringent NAAQS for particulate matter, which may require some states to change existing implementation plans. These NAAQS are expected to be implemented by 2003. These NAAQS were effectively affirmed by the U.S. Supreme Court on February 27, 2001, subject to the resolution of certain issues pending on remand. That decision upheld the constitutionality of EPA's NAAQS statutory authority, finding that EPA acted properly in not considering costs in setting the NAAQS, and remanded the case to the U.S. Court of Appeals for the D.C. Circuit to dispose of any remaining challenges to the rules. On March 26, 2002, the U.S. Court of Appeals for the D.C. Circuit upheld EPA's NAAQS. Because coal mining operations and utilities emit particulate matter, our mining operations and utility customers are likely to be directly affected when the revisions to the NAAQS are implemented by the states. Both Congress and EPA are considering additional controls on other air pollutants emitted by electric utilities. Any such controls, if adopted, could adversely affect the market for coal.

EPA has filed suit against a number of our customers over implementation of new source performance standards and preconstruction review requirements for new sources and major modifications under the prevention of significant deterioration and nonattainment regulations. This issue surrounds the issue of what constitutes regular maintenance versus new construction. Some of our customers have agreed to or proposed settlements with EPA while others are preparing for litigation. These and other regulatory developments may restrict the size of our market, and the type of coal in demand. This in turn could adversely affect our ability to develop new mines, or could require us or our customers to modify existing operations.

#### *Framework Convention On Global Climate Change (Kyoto Protocol)*

The United States and more than 160 other nations are signatories to the Kyoto Protocol which is intended to limit or capture emissions of greenhouse gases, such as carbon dioxide. The Kyoto Protocol established a binding set of emissions targets for developed nations. The specific limits vary from country to country. Under the terms of the Kyoto Protocol, the United States would be required to reduce emissions to 93% of 1990 levels over a five-year budget period from 2008 through 2012. The Clinton Administration signed the Kyoto Protocol in November 1998. Although the U.S. Senate has not ratified the Kyoto Protocol and no comprehensive regulations focusing on greenhouse gas emissions have been enacted, efforts to control greenhouse gas emissions could result in reduced use of coal if electric power generators switch to lower carbon sources of fuel.

In March 2001, President Bush expressed his opposition to the Kyoto Protocol and stated that he did not believe that the government should impose mandatory carbon dioxide emission reductions on power plants. In February 2002, President Bush proposed voluntary actions to reduce greenhouse gas intensity of the United States. Greenhouse gas intensity measures the ratio of greenhouse gas emissions, such as carbon dioxide, to

economic output. The President's climate change initiative calls for a reduction in greenhouse gas intensity over the next ten years, which is approximately equivalent to the reduction that has occurred over each of the past two decades. These restrictions, if established through regulation or legislation, could have a material adverse effect on our business, financial condition and results of operations.

#### *Clean Water Act (CWA)*

The Federal CWA affects coal mining operations by imposing restrictions on effluent discharge into waters. Regular monitoring, as well as compliance with reporting requirements and performance standards, are preconditions for the issuance and renewal of permits governing the discharge of pollutants into water. We are also subject to CWA §404, which imposes permitting and mitigation requirements associated with the dredging and filling of wetlands. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact wetlands. We believe we have obtained all necessary wetlands permits required under CWA §404. However, mitigation requirements under those existing, and possible future, wetlands permits may vary considerably. In January 2001, the U.S Supreme Court issued a decision narrowing the CWA jurisdiction over isolated wetlands not connected to navigable waters. It is not yet known how this will affect wetland mitigation and protection programs under federal and state laws. At this time we do not anticipate any increase in such requirements or in post-mining reclamation accrual requirements. For that reason, the setting of post-mine reclamation accruals for such mitigation projects is difficult to ascertain with certainty. We believe that we have obtained all permits required under the CWA as traditionally interpreted by the responsible agencies. Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of any such permitting requirements.

However, each individual state is required to submit to EPA their biennial CWA §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 states and EPA to establish reasonable TMDLs that will accommodate expansion. These and other regulatory developments may restrict our ability to develop new mines, or could require us or our customers to modify existing operations, the extent of which we cannot accurately or reasonably predict.

#### *Safe Drinking Water Act (SDWA)*

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

In addition to establishing the underground injection control program, the Federal 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, the Federal SDWA defines a "public water system" for purposes of regulatory jurisdiction as a system for the provision to the public of water for human consumption through pipes or other constructed conveyances, if the system has at least fifteen service connections or regularly serves at least twenty-five individuals. It is unlikely that any of our reclamation activities would require the provision of such a "public water system." While we have 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.

#### *Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)*

The Federal CERCLA and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA, and similar state laws, joint and several liability may be imposed on waste generators, site owners and operators and others regardless of fault or the legality of the original disposal activity. Some products used by coal companies in operations, such as chemicals, generate waste containing hazardous substances, which are governed by the statute. Thus, coal mines that we currently own or have previously owned or operated, and sites to which we sent waste materials, may be subject to liability under CERCLA and similar state laws. We have been, on rare occasions, the subject of administrative proceedings, litigation and investigations relating to CERCLA matters, none of which has had a material adverse effect on our financial condition or results of operations. We cannot assure you that we will not become involved in future proceedings, litigation or investigations, or that liabilities arising out of any such proceedings will not be material.

#### *Toxic Substances Control Act (TSCA)*

The Federal TSCA regulates, among other things, electrical equipment containing PCBs in excess of 50 parts-per-million. Specifically, TSCA's PCB rules require that all PCB-containing equipment be properly labeled, stored, and disposed of, and require the on-site maintenance of annual records regarding the presence and use of equipment containing PCBs in excess of 50 parts-per-million. Because the regulated PCB-containing electrical equipment in use in our operations is owned by the utilities that serve the operations where they are located, and because the use of PCB-containing fluids in such equipment is in the process of being phased out, we do not believe TSCA will have a material impact on our operations.

#### *Resource Conservation and Recovery Act (RCRA)*

The Federal RCRA affects 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 exempted from regulation under RCRA by statute. RCRA also allows EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, we do not believe that these costs will have a material impact on our operations.

#### *Coal Combustion By-Products*

In 2000, EPA declined to impose hazardous wastes regulatory controls on the disposal of some coal combustion by-products, including the practice of using coal combustion by-products as minefill. However, EPA is currently evaluating the possibility of placing additional solid waste burdens on the disposal of these types of materials, but it may be several years before these standards will be developed.

While we cannot predict the ultimate outcome of EPA's assessment, we believe the beneficial uses of coal combustion by-products (like the practice of placing this by-product in abandoned mine areas) that we employ do not constitute poor environmental practices because, among other things, our CWA discharge permits for treated acid mine drainage contain parameters for pollutants of concern, such as metals, and those permits require monitoring and reporting of effluent quality data. Small quantities of regulated hazardous wastes are generated at some of our facilities. However, we do not believe that the cost of complying with applicable regulations for those wastes will have a material impact on our operations.

### **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 where 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 property are subject to federal, state and local regulation. The costs of compliance with these requirements should not have a material adverse effect on our business, financial condition or results of operations.

### **Employees**

We have approximately 1,745 employees, including approximately 100 corporate employees and approximately 1,645 employees involved in active mining operations. Our work-force is entirely union-free. Relations with our employees are generally good.

## **ITEM 2. PROPERTIES**

### **Coal Reserves**

We must obtain permits from applicable state regulatory authorities before beginning to mine particular reserves. 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 overburden fills and water containment areas, and reclamation of the area after coal extraction. We are required to post bonds to secure performance under our permits. 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. We begin preparing applications for permits for areas that we intend to mine sufficiently in advance of our planned mining activities to allow adequate time to complete the permitting process. Regulatory authorities have considerable discretion in the timing of permit issuance, and the public has rights to comment on and otherwise engage in the permitting process, including intervention in the courts. For the reserves set forth in the table below, we are not currently aware of matters which would significantly hinder our ability to obtain future mining permits on a timely basis.

Our reported coal reserves are those that 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.

As of December 31, 2001, we had approximately 400.7 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.

The following table sets forth reserve information, as of December 31, 2001, about each of our mining complexes.

Operations	Mine Type	Heat Content (Btus per pound)	Proven and Probable Reserves				Reserve Assignment	
			Pounds SO <sub>2</sub> per MMBtu			Total	Assigned	Unassigned
(tons in millions)								
<i>Illinois Basin Operations</i>								
Dotiki	Underground	12,500	-	-	88.9	88.9	88.9	-
Pattiki	Underground	11,700	-	-	53.9	53.9	53.9	-
Hopkins County	Underground	11,300	-	-	21.4	21.4	1.4	20.0
Coal	/ Surface	-	-	-	11.6	11.6	11.6	-
Gibson County	Underground	11,600	-	36.2	-	36.2	36.2	-
Coal (North)								
Gibson County	Underground	11,600	-	55.0	44.9	99.9	-	99.9
Coal (South)								
Region Total			-	91.2	220.7	311.9	192.0	119.9
<i>East Kentucky Operations</i>								
Pontiki/Excel	Underground	12,800	16.0	1.9	-	17.9	17.9	-
MC Mining/Excel	Underground	12,800	22.0	-	-	22.0	22.0	-
Region Total			38.0	1.9	-	39.9	39.9	-
<i>Maryland Operations</i>								
Mettiki	Underground	13,000	-	15.0	18.1	33.1	18.1	15.0
Mettiki (WV)	Underground	13,000	-	-	15.8	15.8	10.2	5.6
			-	15.0	33.9	48.9	28.3	20.6
Total			38.0	108.1	254.6	400.7	260.2	140.5
% of Total			9.5%	27.0%	63.5%	100.0%	64.9%	35.1%

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 ½ mile apart, and are projected to extend as a ¼ mile wide belt around each point of measurement and (b) probable reserves is that the points of observation are between ½ and 1 ½ miles apart and are projected to extend as a ½ mile wide belt that lies ¼ mile from the points of measurement.

Reserve estimates will change from time to time in reflection of mining activities, analysis and 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 all of our reserves as of March 31, 1999 in conjunction with our initial public offering.

Reserves represent that part of a mineral deposit that can be economically and legally extracted or produced, and reflects estimated losses involved in producing a saleable product. All of our reserves are steam coal. The 38.0 million tons of reserves listed as <1.2 pounds of SO<sub>2</sub> per MMBtu are compliance coal.

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.

A permit application related to the 15.8 million tons of reserves controlled by Mettiki (WV) has been submitted to the West Virginia Department of Environmental Protection ("West Virginia DEP"). The West Virginia DEP has not advised us concerning the status of the permit application. In regard to a different permit application concerning other coal reserves, on January 29, 2002, the West Virginia DEP denied such permit application related to 3.1 million tons of coal that are not contiguous to the 15.8 million tons of reserves. Consequently, the 3.1 million tons is classified as a non-reserve coal deposit and not included in our reported reserves. The permit denial has been appealed to the West Virginia Surface Mining Board.

We control certain leases for coal deposits that are nearby, 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 – 2.6 million tons, Pattiki – 5.8 million tons, Gibson County North – 2.0 million tons, and Gibson County South – 4.3 million tons.

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

The following table sets forth production data about each of our mining complexes.

Operations	Tons Produced			Transportation	Equipment
	2001	2000	1999		
	(tons in millions)				
<i>Illinois Basin Operations</i>					
Dotiki	4.6	3.9	3.6	CSX; truck; barge	CM
Pattiki	1.9	2.3	2.3	CSX; truck; barge	CM
Hopkins County Coal	2.0	2.1	2.6	CSX, PAL; truck	DL; CM
Gibson County Coal (North)	1.7	0.1	-	Truck	CM
Region Total	<u>10.2</u>	<u>8.4</u>	<u>8.5</u>		
<i>East Kentucky Operations</i>					
Pontiki/Excel	1.7	1.9	1.8	NS; truck	CM
MC Mining/Excel	1.1	0.8	1.0	NS; truck	CM
Region Total	<u>2.8</u>	<u>2.7</u>	<u>2.8</u>		
<i>Maryland Operations</i>					
Mettiki	2.7	2.6	2.8	Truck; CSX	LW; CM
Total	<u>15.7</u>	<u>13.7</u>	<u>14.1</u>		

CSX -- CSX Railroad

PAL -- Paducah and Louisville Railroad

NS -- Norfolk & Southern Railroad

CM -- Continuous Miner

DL -- Dragline with Stripping Shovel, Front End Loaders and Dozers

LW -- Longwall

## RISK FACTORS

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our common units could decline.

### *Risks Inherent in Our Business*

- Competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.
- We expect most newly constructed power plants to be fueled by natural gas. Any change in consumption patterns by utilities away from the use of coal could affect our ability to sell the coal we produce.
- 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 contracts. This could affect the stability and profitability of our operations.
- Some of our long-term contracts contain provisions allowing for the renegotiation of prices and, in some instances, the termination of the contract or the suspension of purchases by customers.
- Some of our long-term contracts require us to supply all of our customers coal needs. If these customers' coal requirements decline, our revenues under these contracts will also drop.
- A substantial portion of our coal has a high-sulfur content. This coal may become more difficult to sell because the Clean Air Act may impact the ability of electric utilities to burn high-sulfur coal through the regulation of emissions.
- We depend on a few customers for a significant portion of our revenues, and the loss of one or more significant customers could impact our ability to sell the coal we produce.
- Litigation relating to disputes with our customers may result in substantial costs, liabilities and loss of revenues.
- The term of each of the agreements associated with the coal synfuel facility at Hopkins County Coal is subject to early cancellation provisions customary for transactions of these types, including the unavailability of synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. Therefore, the continuation of the operating revenues associated with the coal synfuel production facility cannot be assured.
- Any loss of the benefit from state tax credits may affect adversely our ability to pay distributions.
- Coal mining is subject to inherent risks that are beyond our control and these risks may not be fully covered under our insurance policies.
- Any significant increase in transportation costs or disruption of the transportation of our coal may impair our ability to sell coal.
- We may not be able to grow successfully through future acquisitions, and we may not be able to effectively integrate the various businesses or properties we do acquire.
- Our business may be adversely affected if we are unable to replace our coal reserves.

- The estimates of our reserves may prove inaccurate, and unitholders should not place undue reliance on these estimates.
- Cash distributions are not guaranteed and may fluctuate with our performance. In addition, our managing general partner's discretion in establishing reserves may negatively impact a unitholder's receipt of cash distributions.
- Our indebtedness may limit our ability to borrow additional funds, make distributions to unitholders or capitalize on business opportunities.

*Risks Inherent in an Investment in the Partnership*

- Unitholders have limited voting rights and do not control our managing general partner.
- We may issue additional common units without the approval of common unitholders, which would dilute existing unitholders' interests.
- The issuance of additional common units, including upon conversion of subordinated units, will increase the risk that we will be unable to pay the full minimum quarterly distribution on all common units.
- Cost reimbursements to our general partners may be substantial and will reduce our cash available for distribution.
- Our managing general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.
- Unitholders may not have limited liability under some circumstances.

*Regulatory Risks*

- Federal and state laws require bonds to secure our obligations related to (a) the statutory requirement that we return mined property to its approximate original condition and (b) workers compensation. We may have difficulty maintaining our surety bonds for mine reclamation as well as workers' compensation and black lung benefits. As of December 31, 2001, we had \$64.1 million of surety bonds in place. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal law would have a material adverse effect on us.
- We are subject to federal, state and local regulations on health, safety, environmental and numerous other matters. These regulations increase our costs of doing business, or discourage customers from buying our coal.
- We have black lung benefits and workers' compensation obligations that could increase if new legislation is enacted.
- The Clean Air Act affects our customers and could significantly influence their purchasing decisions. New regulations under the Clean Air Act could also reduce demand for our coal.

- The passage of legislation responsive to the Kyoto Protocol could result in a reduced use of coal by electric power generators. Any such reduction in use could adversely affect our revenues and results of operations.
- We are subject to the Clean Water Act which imposes limitations, and monitoring and reporting obligations, on our discharge of pollutants into water. Those limitations and obligations may become more stringent and result in restricted operations and increased costs.
- We are subject to the Safe Drinking Water Act, which imposes various requirements on us.
- We are subject to reclamation, mine closure and real property restoration regulatory obligations and must accrue for the estimated cost of complying with these regulations.
- We could incur significant costs under federal and state Superfund and waste management statutes.

*Tax Risks to Common Unitholders*

- The IRS could choose to treat us as a corporation, which would substantially reduce the cash available for distribution to unitholders.
- We have not requested an IRS ruling with respect to our tax treatment.
- You may be required to pay taxes on income from us even if you receive no cash distributions.
- Tax gain or loss on disposition of common units could be different than expected.
- Common unitholders, other than individuals who are U.S. residents, may experience adverse tax consequences from owning common units.
- We have registered with the IRS as a tax shelter. This may increase the risk of an IRS audit of us or a common unitholder.
- We treat a purchaser of common units as having the same tax benefits as the seller. The IRS may challenge this treatment, which could adversely affect the value of common units.
- Common unitholders will likely be subject to state and local taxes as a result of an investment in common units.

**ITEM 3. LEGAL PROCEEDINGS**

We are subject to various types of litigation in the ordinary course of our business. Disputes with our customers over the provisions of long-term coal supply contracts arise occasionally and generally relate to, among other things, coal quality, quantity, pricing, and the existence of force majeure conditions. Other than the contract dispute with PSI described under "Other" in Item 8. Financial Statements and Supplementary Data. – Note 15. Commitments and Contingencies, we are not involved in any litigation involving our long-term coal supply contracts. However, we cannot assure you that disputes will not occur or that we will be able to resolve those disputes in a satisfactory manner. We are not engaged in any litigation which we believe is material to our operations, including under the various environmental protection statutes to which we are subject. The information under "General Litigation" under "Item 8. Financial Statements and Supplementary Data. – Note 15. Commitments and Contingencies" is incorporated herein by this reference.

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

None.

### PART II

#### ITEM 5. MARKET FOR REGISTRANT'S COMMON UNITS AND RELATED UNITHOLDER MATTERS

The common units representing limited partners' interest are listed on the Nasdaq National Market under the symbol "ARLP." The common units began trading on August 20, 1999, when the market price for the initial public offering of the common units was \$19.00 per unit. On March 28, 2002, the closing market price for the common units was \$24.18 per unit. There were approximately 9,200 record holders and beneficial owners (held in street name) at December 31, 2001 of common units.

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

	<u>High</u>	<u>Low</u>	<u>Distributions Per Unit</u>
1st Quarter 2000	\$14.50	\$12.13	\$0.50 (paid May 15, 2000)
2nd Quarter 2000	\$15.13	\$12.63	\$0.50 (paid August 14, 2000)
3rd Quarter 2000	\$17.75	\$14.25	\$0.50 (paid November 14, 2000)
4th Quarter 2000	\$18.25	\$15.00	\$0.50 (paid February 14, 2001)
1st Quarter 2001	\$22.50	\$16.63	\$0.50 (paid May 15, 2001)
2nd Quarter 2001	\$29.99	\$20.63	\$0.50 (paid August 14, 2001)
3rd Quarter 2001	\$25.20	\$21.73	\$0.50 (paid November 14, 2001)
4th Quarter 2001	\$27.45	\$22.65	\$0.50 (paid February 14, 2002)

We have also issued 6,422,531 subordinated units, all of which are held by the special general partner, for which there is no established public trading market.

We will distribute to our partners (including holders of subordinated units), on a quarterly basis, all of our available cash. "Available cash" generally means, with respect to any quarter, all cash on hand at the end of each quarter less cash reserves in the amount necessary or appropriate in the reasonable discretion of the managing general partner to (a) provide for the proper conduct of our business, (b) comply with applicable law of any debt instrument or other agreement of ours or any of its affiliates, or (c) provide funds for distributions to unitholders and the general partners for any one or more of the next four quarters. Available cash is defined in our partnership agreement listed as an exhibit of this Annual Report on Form 10-K. Our partnership agreement defines minimum quarterly distributions (MQDs) as \$0.50 for each full fiscal quarter. Distributions of available cash to the holder of the subordinated units are subject to the prior rights of the holders of the common units to receive MQDs for each quarter during the subordination period, and to receive any arrearages in the distribution of the MQDs on the common units for prior quarters during the subordination period. The subordination period will generally not end before September 30, 2004. Under

certain circumstances, up to half of the subordinated units may convert into common units before the end of the subordination period, which will generally not occur before September 30, 2003.

## ITEM 6. SELECTED FINANCIAL DATA

On August 20, 1999, we completed our initial public offering whereby we became the successor to the business of our predecessor. Our selected pro forma and historical financial data below was derived from our audited consolidated financial statements as of December 31, 2001, 2000 and 1999, for the years ended December 31, 2001 and 2000 and the period from our commencement of operations (on August 20, 1999) to December 31, 1999, the audited combined financial statements of our predecessor, as of August 19, 1999, and for the period from January 1, 1999 to August 19, 1999, and as of and for the years ended December 31, 1998, and 1997.

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

	Partnership				Predecessor		
	Year Ended December 31,		Pro Forma Year Ended December 31, 1999 (1)	From Commencement of Operations (on August 20, 1999) to December 31, 1999	For the period from January 1, 1999 to August 19, 1999		
	2001	2000			1998	1997	
<b>Statements of Income:</b>							
<b>Sales and operating revenues</b>							
Coal sales	\$ 422.0	\$ 347.2	\$ 345.9	\$ 128.8	\$ 217.0	\$ 357.4	\$ 305.3
Transportation revenues (2)	18.1	13.5	19.1	4.9	14.2	41.4	42.7
Other sales and operating revenues	6.2	2.8	0.9	0.4	0.6	4.5	8.5
Total revenues	<u>446.3</u>	<u>363.5</u>	<u>365.9</u>	<u>134.1</u>	<u>231.8</u>	<u>403.3</u>	<u>356.5</u>
<b>Expenses</b>							
Operating expenses	308.0	257.4	242.0	89.9	152.1	237.6	197.4
Transportation expenses (2)	18.1	13.5	19.1	4.9	14.2	41.4	42.7
Outside purchases	31.8	16.9	24.2	6.4	17.7	51.2	49.8
General and administrative	17.7	15.2	15.1	6.2	8.9	15.3	15.4
Depreciation, depletion and amortization	45.5	39.1	39.7	15.1	24.6	39.8	33.7
Interest expense	16.8	16.6	19.4	5.9	0.1	0.2	-
Unusual items (3)	-	(9.5)	-	-	-	5.2	-
Total expenses	<u>437.9</u>	<u>349.2</u>	<u>359.5</u>	<u>128.4</u>	<u>217.6</u>	<u>390.7</u>	<u>339.0</u>
Income from operations	8.4	14.3	6.4	5.7	14.2	12.6	17.5
Other income (expense)	0.8	1.3	1.2	0.6	0.5	(0.1)	0.5
Income before income taxes and cumulative effect of accounting change	9.2	15.6	7.6	6.3	14.7	12.5	18.0
Income tax expense	-	-	-	-	4.5	3.8	4.3
Income before cumulative effect of accounting change	9.2	15.6	7.6	6.3	10.2	8.7	13.7
Cumulative effect of accounting change (4)	7.9	-	-	-	-	-	-
Net income	<u>\$ 17.1</u>	<u>\$ 15.6</u>	<u>\$ 7.6</u>	<u>\$ 6.3</u>	<u>\$ 10.2</u>	<u>\$ 8.7</u>	<u>\$ 13.7</u>
Basic net income per limited partner unit	<u>\$ 1.09</u>	<u>\$ 0.99</u>	<u>\$ 0.48</u>	<u>\$ 0.40</u>			
Basic net income per limited partner unit before accounting change	<u>\$ 0.58</u>	<u>\$ 0.99</u>	<u>\$ 0.48</u>	<u>\$ 0.40</u>			
Diluted net income per limited partner unit	<u>\$ 1.07</u>	<u>\$ 0.98</u>	<u>\$ 0.48</u>	<u>\$ 0.40</u>			
Diluted net income per limited partner unit before accounting change	<u>\$ 0.57</u>	<u>\$ 0.98</u>	<u>\$ 0.48</u>	<u>\$ 0.40</u>			
Weighted average number of units outstanding-basic	<u>15,405,311</u>	<u>15,405,311</u>	<u>15,405,311</u>	<u>15,405,311</u>			
Weighted average number of units outstanding-diluted	<u>15,684,550</u>	<u>15,551,062</u>	<u>15,405,311</u>	<u>15,405,311</u>			
<b>Balance Sheet Data:</b>							
Working capital (deficit)	\$ (2.3)	\$ 38.6	\$ -	\$ 61.2	\$ 11.2	\$ 7.1	\$ 10.3
Total assets	290.9	309.2	-	314.8	262.8	261.1	245.8
Long-term debt	211.3	226.3	-	230.0	1.8	1.7	1.9
Total liabilities	337.8	341.0	-	330.7	110.2	108.3	87.0
Net Parent investment	-	-	-	-	151.6	152.8	158.8
Partners' capital (deficit)	(46.9)	(31.8)	-	(15.9)	-	-	-
<b>Other Operating Data:</b>							
Tons sold	17.0	15.0	15.0	5.6	9.4	15.1	12.4
Tons produced	15.7	13.7	14.1	5.3	8.8	13.4	10.9
Revenues per ton sold (5)	\$ 25.19	\$ 23.33	\$ 23.12	\$ 23.07	\$ 23.15	\$ 23.97	\$ 25.31
Cost per ton sold (5)	\$ 21.03	\$ 19.30	\$ 18.75	\$ 18.30	\$ 19.01	\$ 20.14	\$ 21.18
<b>Other Financial Data:</b>							
EBITDA (7)	\$ 79.4	\$ 71.3	\$ 66.7	\$ 27.3	\$ 39.4	\$ 52.5	\$ 51.7
Net cash provided by (used in) operating activities	63.7	71.4	-	(13.9)	32.9	50.5	53.2
Net cash used in investing activities	(26.2)	(41.0)	-	(43.9)	(21.5)	(35.6)	(22.4)
Net cash provided by (used in) financing activities	(35.2)	(31.4)	-	65.8	(11.4)	(14.9)	(30.8)
Maintenance capital expenditures (8)	24.4	21.2	6.0	6.0	15.5	17.2	15.2

- (1) The unaudited selected pro forma financial and operating data for the year ended December 31, 1999, is based on the historical financial statements of the partnership from our commencement of operations on August 20, 1999, through December 31, 1999, and our predecessor for the period from January 1, 1999, through August 19, 1999. The pro forma results of operations reflect certain pro forma adjustments to the historical results of operations as if we had been formed on January 1, 1999. The pro forma adjustments include (a) pro forma interest on debt assumed by us and (b) the elimination of income tax expense as income taxes will be borne by the partners and not by us. The pro forma adjustments do not include approximately \$1.0 million of general and administrative expenses that we believe would have been incurred as a result of its being a public entity.
- (2) During the fourth quarter 2000, we adopted the Financial Accounting Standards Board Emerging Issues Task Force Issue No. 00-10 "Accounting for Shipping and Handling Fees and Costs" (EITF No. 00-10). We record the cost of transporting coal to customers through third party carriers and our corresponding direct reimbursement of these costs through customer billings. This activity is separately presented as transportation revenue and expense rather than offsetting these amounts in the consolidated and combined statements of income. There was no cumulative effect of the accounting change on net income and prior periods presented have been reclassified to comply with EITF No. 00-10.
- (3) Represents income from the final resolution of an arbitrated dispute with respect to the termination of a long-term contract, net of impairment charges relating to certain transloading facility assets, partially offset by expenses associated with other litigation matters in 2000 and the net loss incurred during the temporary closing of one of our mining complexes in the second half of 1998.
- (4) Represents the cumulative effect of the change in the method of estimating coal workers' pneumoconiosis ("black lung") benefits liability effective January 1, 2001. See "Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations. - Critical Accounting Policies. and Item 8. Financial Statements and Supplementary Data. - Note 3. Accounting Change."
- (5) Revenues per ton sold is based on the total of coal sales and other sales and operating revenues divided by tons sold.
- (6) Cost per ton sold is based on the total of operating expenses, outside purchases and general and administrative expenses divided by tons sold.
- (7) EBITDA is defined as income before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA should not be considered as an alternative to net income, income before income taxes, cash flows from operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA has not been adjusted for unusual items nor the cumulative effect of an accounting change. EBITDA is not intended to represent cash flow and does not represent the measure of cash available for distribution, but provides additional information for evaluating our ability to make the MQDs. Our method of computing EBITDA also 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 arrangements).
- (8) Our maintenance capital expenditures, as defined under the terms of our partnership agreement, are defined as those capital expenditures required to maintain, over the long term, the operating capacity of our capital assets. Maintenance capital expenditures for our predecessor reflect our historical designation of maintenance capital expenditures.

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

### General

The following discussion of our financial condition and results of operations and our predecessor should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the

following financial information, see "Item 8. Financial Statements and Supplementary Data. - Note 1. Organization and Presentation and Note 2. Summary of Significant Accounting Policies."

### **Critical Accounting Policies**

From our Summary of Significant Accounting Policies, we have identified the following accounting policies that require the exercise of our most difficult, complex and subjective levels of judgment. Our judgments in the following areas are principally based on estimates and assumptions that affect the reported amounts and disclosures in the consolidated and combined financial statements. See "Item 8. Financial Statements and Supplementary Data." Actual results that are influenced by future events could materially differ from the current estimates.

#### *Long-Lived Assets*

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. The amount of an impairment is measured by the difference between the carrying value and the fair value of the asset, which is based on cash flows from that asset, discounted at a rate commensurate with the risk involved.

#### *Reclamation and Mine Closing Costs*

The Federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes require that mine property be restored in accordance with specified standards and an approved reclamation plan. We record the liability for the estimated cost of future mine reclamation and closing procedures on a present value basis when incurred and the associated cost is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to sealing portals at underground mines and to reclaiming the final pit and support acreage at surface mines. Other costs common to both types of mining are related to removing or covering refuse piles and settling ponds, and dismantling preparation plants, other facilities and roadway infrastructure. We had accrued liabilities of \$16.5 million and \$16.0 million for these costs at December 31, 2001 and 2000, respectively.

#### *Workers' Compensation and Pneumoconiosis ("Black Lung") Benefits*

We provide income replacement and medical treatment for work related traumatic injury claims as required by the applicable state law. We provide for these claims through self-insurance programs. The liability for traumatic injury claims is the estimated present value of current workers' compensation benefits based on an annual actuarial study performed by an independent actuary. The actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including development patterns, mortality, medical costs and interest rates. We had accrued liabilities of \$22.1 million and \$20.6 million for these costs at December 31, 2001 and 2000, respectively.

Coal mining companies are subject to the Federal Coal Mine Health and Safety Act of 1969, as amended, and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker's pneumoconiosis ("black lung"). We provide for these claims through a self-insurance programs. Our estimated black lung liability is based on an annual actuarial study performed by an independent actuary. The actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates. We had accrued liabilities of \$15.1 million and \$22.1 million for these benefits at December 31, 2001 and 2000, respectively.

Effective January 1, 2001, we changed our method of estimating black lung benefits to the service cost method described in Statement of Financial Accounting Standards ("SFAS") No. 106, "Employer's

Accounting for Postretirement Benefits Other Than Pensions,” which method is permitted under SFAS No. 112 “Employers’ Accounting for Postemployment Benefits.” Recently, governmental regulations regarding the federal black lung benefits claims approval process were issued. These new regulations specifically define the black lung disability as progressive and also expand the definition of pneumoconiosis to mandate consideration of diseases that are caused by factors other than exposure to coal dust. We believe the change to the SFAS No. 106 measurement methodology better matches black lung costs over the service lives of the miners who ultimately receive the black lung benefits and is more reflective of the recently enacted regulations, which place significant emphasis on coal miners’ future years of employment in the coal industry. We previously accrued the black lung benefits liability at the present value of the actuarially determined current and future estimated black lung benefit payments utilizing the methodology prescribed under SFAS No. 5 “Accounting for Contingencies,” which was also permitted by SFAS No. 112.

## **Business**

We are a diversified producer and marketer of coal to major U.S. utilities and industrial users. In 2001, our total production was 15.7 million tons and our total sales were 17.0 million tons. The coal we produced in 2001 was approximately 28.7% low-sulfur coal, 17.2% medium-sulfur coal and 54.1% high-sulfur coal.

At December 31, 2001, we had approximately 400.6 million tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland and West Virginia. We believe we control adequate reserves to implement our currently contemplated mining plans. In addition, there are substantial unleased reserves on adjacent properties that we intend to acquire or lease as our mining operations approach these areas.

In 2001, approximately 83% of our sales tonnage was consumed by electric utilities with the balance consumed by cogeneration plants and industrial users. Our largest customers in 2001 were Seminole, TVA, and VEPCO. We have had relationships with these customers for at least 15 years. In 2001, approximately 78% of our sales tonnage, including approximately 75% of our medium- and high-sulfur coal sales tonnage, was sold under long-term contracts. The balance of our sales were made on the spot market. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2001, approximately 91% 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 recently entered into long-term agreements with SSO to host and operate its coal synfuel production facility, supply coal feedstock, assist with coal synfuel marketing, and provide other services through December 31, 2007. These agreements provide us with coal sales or service fees from SSO based on the synfuel facility throughput tonnage, which amount is dependent on the ability of the facility’s owners to use certain qualifying tax credits applicable to the facility. The term of each agreement is subject to early cancellation provisions customary for transactions of these types, including the unavailability of coal synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. Therefore, the continuation of the operating revenues associated with the coal synfuel production facility cannot be assured. However, we have put in place “back up” coal supply agreements with each coal synfuel customer, which automatically provide for sale of our coal to them in the event they do not receive coal synfuel.

One of our business strategies is to continue to make productivity improvements to remain a low cost producer in each region in which we operate. Our principal expenses related to the production of coal are labor and benefits, equipment, materials and supplies, maintenance, royalties and excise taxes. Unlike most of our competitors in the eastern U.S., we employ a totally union-free workforce. Many of the benefits of the union-free workforce are not necessarily reflected in direct costs, but we believe are related to higher productivity. In addition, while we do not pay our customers’ transportation costs, they may be substantial and often the determining factor in a coal consumer’s contracting decision. Our mining operations are located near

many of the major eastern utility generating plants and on major coal hauling railroads in the eastern U.S. We believe this gives us a transportation cost advantage compared to many of our competitors.

## Results Of Operations

### *2001 Compared with 2000*

*Coal sales.* Coal sales for 2001 increased 21.5% to \$422.0 million from \$347.2 million for 2000. The increase of \$74.8 million was primarily attributable to higher sales prices and volume reflecting increased utility demand, increased activity in the domestic coal brokerage market due to favorable spot price levels and additional revenues from the new Gibson County Coal mining complex, which opened in late 2000. Tons sold increased 13.3% to 17.0 million for 2001 from 15.0 million in 2000. Tons produced increased 14.9% to 15.7 million for 2001 from 13.7 million for 2000.

*Transportation revenues.* Transportation revenues for 2001 increased 33.9% to \$18.1 million from \$13.5 million for 2000. The increase of \$4.6 million was primarily attributable to the increase in tons sold. We reflect reimbursement of the cost of transporting coal to customers through third party carriers as transportation revenues and the corresponding expense as transportation expense in the consolidated statements of income. No margin is realized on transportation revenues.

*Other sales and operating revenues.* Other sales and operating revenues increased to \$6.2 million for 2001 from \$2.8 million for 2000. The increase of \$3.4 million is attributable to additional service fees associated with increased volumes at a third party coal synfuel production facility at our Hopkins County Coal mining complex. See the discussion immediately above under "Business."

*Operating expenses.* Operating expenses increased 19.7% to \$308.0 million for 2001 from \$257.4 million for 2000. The increase of \$50.6 million resulted from increased sales volumes as well as additional operating expenses associated with a full year of operation at Gibson County Coal, which opened in late 2000 and difficult mining conditions encountered at several operations. Those difficult mining conditions placed an undue burden on equipment scheduled for replacement, resulting in unanticipated equipment failures and higher maintenance costs.

*Transportation expenses.* See "Transportation Revenues" above concerning the increase in transportation expenses.

*Outside purchases.* Outside purchases increased to \$31.8 million for 2001 from \$16.9 million for 2000. The increase of \$14.9 million resulted from increased activity in the domestic coal brokerage market due to improved profit margins on spot coal sales, which resulted in increased volumes at higher purchase prices. The higher brokerage volumes are largely attributable to short-term opportunities in the domestic coal brokerage markets, which are not expected to be material in the future.

*General and administrative.* General and administrative expenses increased 16.8% to \$17.7 million for 2001 from \$15.2 million for 2000. The increase of \$2.5 million was primarily attributable to higher accruals related to the Short-Term Incentive Plan, combined with additional restricted units granted under the Long-Term Incentive Plan. The Long-Term Incentive Plan accrual is impacted by the increased market value of the common units.

*Depreciation, depletion and amortization.* Depreciation, depletion and amortization expenses increased 16.1% to \$45.5 million for 2001 from \$39.1 million for 2000. The increase of \$6.4 million primarily resulted from additional depreciation expense associated with a full year of operation at Gibson County Coal, which opened in late 2000.

*Interest expense.* Interest expense was comparable for 2001 and 2000 at \$16.8 million and \$16.6 million, respectively.

*Cumulative effect of accounting change.* Effective January 1, 2001, we changed our method of estimating our black lung benefits liability. See the discussion immediately above under "Workers' Compensation and Pneumoconiosis ("Black Lung") Benefits."

EBITDA (income before net interest expense, income taxes, depreciation, depletion and amortization) increased 11.3% to \$79.4 million for 2001 compared with \$71.3 million for 2000. The \$8.1 million increase was primarily attributable to higher sales prices and volumes reflecting increased utility demand during 2001 and a full year of operations at Gibson County Coal, which opened in late 2000, and the increased revenue from the third party coal synfuel facility at Hopkins County Coal.

EBITDA should not be considered as an alternative to net income, income before income taxes, cash flows from operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA has not been adjusted for unusual items nor the cumulative effect of an accounting change. EBITDA is not intended to represent cash flow and does not represent the measure of cash available for distribution, but provides additional information for evaluating our ability to pay MQDs. Our method of computing EBITDA also 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).

#### *2000 Compared with 1999*

In comparing 2000 to 1999, the partnership and predecessor periods for 1999 have been combined. Since we maintained the historical cost basis of our predecessor's net assets, we believe that the combined partnership and predecessor results for 2000 are comparable with 1999. The interest expense associated with the debt incurred concurrent with the closing of our initial public offering is applicable only to the partnership period. See "Item 8. Financial Statements and Supplementary Data. - Note 1. Organization and Presentation."

*Coal sales.* Coal sales for 2000 increased 0.4% to \$347.2 million from \$345.9 million for 1999. The increase of \$1.3 million was primarily attributable to higher sales volumes in the Illinois Basin operations and at the restructured Pontiki operation, which were directly offset by planned reduced participation in coal export brokerage markets. Tons produced decreased 2.9% to 13.7 million for 2000 from 14.1 million for 1999.

*Transportation revenues.* Transportation revenues for 2000 decreased 29.4% to \$13.5 million from \$19.1 million for 1999. The decrease of \$5.6 million was primarily attributable to planned reduced participation in coal export brokerage markets, which generally have higher transportation costs. No margin is realized on transportation revenues.

*Other sales and operating revenues.* Other sales and operating revenues increased to \$2.8 million for 2000 from \$0.9 million for 1999. The increase of \$1.9 million resulted from the introduction of a third party coal synfuel production facility at the Hopkins County Coal mining complex.

*Operating expenses.* Operating expenses increased 6.3% to \$257.4 million for 2000 from \$242.0 million for 1999. The increase of \$15.4 million was a result of: (a) start-up expenses related to the opening of the newly developed Gibson County Coal mining complex during the fourth quarter of 2000, (b) higher sales volumes in the Illinois Basin operations, (c) increased production volumes at the restructured Pontiki

operation, and (d) prolonged adverse mining conditions related to a sandstone intrusion at the Mettiki longwall mine.

*Transportation expenses.* See "Transportation Revenues" above concerning the decrease in transportation expenses.

*Outside purchases.* Outside purchases declined 30.2% to \$16.9 million for 2000 from \$24.2 million for 1999. The decrease of \$7.3 million was the result of lower coal export brokerage volumes. See "Coal sales" above concerning the decrease in coal export brokerage volumes.

*General and administrative.* General and administrative expenses were comparable for 2000 and 1999 at \$15.2 million.

*Depreciation, depletion and amortization.* Depreciation, depletion and amortization expenses were comparable for 2000 and 1999 at \$39.1 million and \$39.7 million, respectively.

*Interest expense.* Interest expense was \$16.6 million for 2000 compared to \$6.0 million for 1999. The increase reflected the full year impact of interest on the \$180 million principal amount of 8.31% senior notes and \$50 million of borrowings on the term loan facility in connection with our initial public offering and concurrent transactions occurring on August 20, 1999. See "Item 8. Financial Statements and Supplementary Data. - Note 1. Organization and Presentation."

*Unusual items.* We were involved in litigation with Seminole with respect to Seminole's termination of a long-term contract for the transloading of coal from rail to barge through our Mt. Vernon terminal in Indiana. The final resolution between the parties, reached in conjunction with an arbitrator's decision rendered during the third quarter of 2000, included both cash payments and amendments to an existing coal supply contract. We recorded income of \$12.2 million, which is net of litigation expenses of approximately \$0.9 million and an impairment charge of \$2.4 million relating to the facility's assets. Additionally, we recorded an expense of \$2.7 million consisting of \$0.7 million relating to a settlement and \$2.0 million attributable to contingencies associated with third party claims arising out of our mining operations. The net effect of these unusual items was \$9.5 million. See "Item 8. Financial Statements. - Note 4. Unusual Items."

*Income before income taxes.* Income before income taxes was \$15.6 million for 2000 compared to \$21.0 million for 1999. The decrease of \$5.4 million was primarily attributable to: (a) start-up expenses related to the opening of the new Gibson County Coal mining complex during the fourth quarter of 2000, (b) increased operating expenses as a result of prolonged adverse mining conditions encountered at the Mettiki longwall mining complex and (c) additional interest expense associated with the debt incurred concurrent with the closing of our initial public offering, partially offset by unusual items recorded during 2000. See "Unusual items" described above.

*Income tax expense.* Our earnings or loss for federal income tax purposes will be included in the tax returns of the individual partners. Accordingly, no recognition is given to income taxes in our accompanying financial statements. Our predecessor was included in the consolidated federal income tax return of Alliance Resource Holdings. Federal and state income taxes were calculated as if our predecessor had filed its return on a separate company basis utilizing an effective income tax rate of 31%.

EBITDA (income before net interest expense, income taxes, depreciation, depletion and amortization) increased 6.9% to \$71.3 million for 2000 compared with \$66.7 million for 1999. The \$4.6 million increase was primarily attributable to increased production and sales volumes at the restructured Pontiki mine and the unusual items recorded during 2000 (see "Unusual items" described above), partially offset by increased operating expenses as a result of adverse mining conditions at the Mettiki longwall mining complex.

EBITDA should not be considered as an alternative to net income, income before income taxes, cash flows from operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA has not been adjusted for unusual items. EBITDA is not intended to represent cash flow and does not represent the measure of cash available for distribution, but provides additional information for evaluating our ability to pay MQDs. Our method of computing EBITDA also 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).

## Liquidity and Capital Resources

### *Liquidity*

We generally satisfy our working capital requirements and fund our capital expenditures and debt service obligations from cash generated from operations and borrowings under our revolving credit facility. We believe that the cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and minimum distribution payments. Nevertheless, our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, some of which are beyond our control.

### *Cash Flows*

Cash provided by operating activities was \$63.7 million in 2001 compared to \$71.4 million in 2000. The decrease in cash provided by operating activities was principally attributable to a decrease in the benefit of working capital reductions from 2000 to 2001.

Net cash used in investing activities was \$26.2 million in 2001 compared to net cash used in investing activities of \$41.0 million in 2000. The decreased use of cash is principally attributable to the liquidation of marketable securities, which was partially offset by increased capital expenditures related to the extension of our Pattiki mine into adjacent coal reserves and the addition of a new mining unit at our Dotiki mine.

Net cash used in financing activities was \$35.2 million for 2001 compared to net cash used in financing activities of \$31.4 million for 2000. Cash used in financing activities during 2001 and 2000 was a direct result of four MQDs of \$0.50 per unit on common and subordinated units outstanding. Additionally, during 2001 we made a scheduled debt payment of \$3.75 million.

We have various commitments primarily related to long-term debt, operating lease commitments related to buildings and equipment, obligations for estimated reclamation and mining closing costs and capital project commitments. We expect to fund these commitments with cash generated from operations, proceeds from marketable securities and borrowings under our revolving credit facility. The following table provides details regarding our contractual cash obligations as of December 31, 2001:

Contractual Obligations	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-Term Debt	\$ 226,250	\$ 15,000	\$ 31,250	\$ 36,000	\$ 144,000
Operating Leases	26,898	3,297	6,336	6,174	11,091
Other Long-Term Obligations (excluding discount effect of \$12.1 million for reclamation liability)	28,649	1,078	3,591	6,056	17,924
Capital projects	15,339	15,339	-	-	-
	<u>\$ 297,136</u>	<u>\$ 34,714</u>	<u>\$ 41,177</u>	<u>\$ 48,230</u>	<u>\$ 173,015</u>

### *Capital Expenditures*

Capital expenditures increased to \$53.7 million in 2001 compared to \$46.2 million in 2000. See "Cash Flow" above concerning the increase in capitalized expenditures. During the year 2000, we approved an extension of our existing Pattiki mine into adjacent coal reserves. The extension involves capital expenditures of approximately \$30.0 million during the 2000-2003 period and is expected to allow the Pattiki mine to continue its existing production level for the next 15 years. Additionally during August 2001, Dotiki began construction of a new mine shaft and ancillary facilities, which is expected to be operational in late 2002 and will provide a new access for miners and supplies. We have contractual commitments of \$15.3 million related to these capital projects.

We currently expect that our average annual maintenance capital expenditures will be approximately \$29.0 million. We have raised this average from 2001 primarily because of our additional operations at Gibson County Coal. We currently expect to fund our anticipated capital expenditures with cash generated from operations and borrowings under our revolving credit facility described below.

### *Notes Offering and Credit Facility*

Concurrently with the closing of our initial public offering, the special general partner issued and the intermediate partnership assumed the obligations with respect to \$180 million principal amount of 8.31% senior notes due August 20, 2014 (Senior Notes). The special general partner also entered into, and the intermediate partnership assumed the obligations under, a \$100 million credit facility (Credit Facility). The Credit Facility consists of three tranches, including a \$50 million term loan facility, a \$25 million working capital facility and a \$25 million revolving credit facility. We had borrowings outstanding of \$46.3 million and \$50 million under the term loan facility and no borrowings outstanding under either the working capital facility or the revolving credit facility at December 31, 2001, and 2000, respectively. The weighted average interest rates on the term loan facility at December 31, 2001, and 2000, were 3.40% and 7.77%, respectively. The Credit Facility expires August 2004. The Senior Notes and Credit Facility are guaranteed by all of the subsidiaries of the intermediate partnership. The Senior Notes and Credit Facility contain various restrictive and affirmative covenants, including the amount of distributions by the intermediate partnership and the incurrence of other debt. We were in compliance with the covenants of both the credit facility and senior notes at December 31, 2001 and 2000.

We entered into agreements with three banks to provide letters of credit in an aggregate amount of \$25.0 million to maintain surety bonds to secure its obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2001, we had \$15.0 million in letters of credit outstanding. The special general partner guarantees the letters of credit.

### *Related Party Transactions*

We purchase coal from affiliates, lease a coal preparation plant and handling facilities at our Gibson County Coal mining complex, lease coal reserves from our special general partner and its affiliates, provide general and administrative services to an affiliate, and receive reclamation services at our Dotiki mine from an affiliate. Our special general partner guarantees our letters of credit and we have a put/call option to purchase a mine operation from Alliance Resource Holdings. See "Item 8. Financial Statements and Supplementary Data. - Note 14. Related Party Transactions" and "Item 13. Certain Relationships and Related Party Transactions."

### *Accruals of Other Liabilities*

We had accruals for other liabilities, including current obligations, totaling \$61.0 million and \$67.1 million at December 31, 2001 and 2000. These accruals were chiefly comprised of workers' compensation benefits, black lung benefits, and costs associated with reclamation and mine closing. These obligations are self-insured. The accruals of these items were based on estimates of future expenditures based on current legislation, related regulations and other developments. Thus, from time to time, our results of operations may be significantly effected by changes to these liabilities. See "Item 8. Financial Statements and Supplementary Data. - Note 12. Reclamation and Mine Closing Costs and Note 13. Pneumoconiosis ("Black Lung") Benefits."

### *Inflation*

Inflation in the U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2001, 2000 or 1999.

### *Recent Accounting Pronouncements*

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," which establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires that all derivatives be recognized as either assets or liabilities in the statement of financial position and be measured at fair value. We have no identified derivative instruments or hedging activities. Accordingly, this standard had no material effect on our consolidated financial statements upon adoption.

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations" and No. 142 "Goodwill and Intangible Assets." SFAS No. 141 eliminates the pooling-of-interests method of accounting for business combinations and requires that all business combinations be accounted for under the purchase method. In addition, it further clarifies the criteria for recognition of intangible assets separately from goodwill. This statement is effective for business combinations initiated after June 30, 2001. SFAS No. 142 discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. This statement is effective January 1, 2002, for all goodwill and other intangible assets included in an entity's statement of financial position at that date, regardless of when those assets were initially recognized. SFAS 141 and 142 are not expected to have a material impact on our financial statements.

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred. When the liability is initially recorded, a cost is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. To settle the liability, the obligation for

its recorded amount is paid or a gain or loss upon settlement is incurred. Since we historically adhered to accounting principles similar to SFAS No. 143 in accounting for its reclamation and mine closing costs, we do not believe that adoption of SFAS No. 143, effective January 1, 2003, will have a material impact on our financial statements.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which is effective for fiscal years beginning after December 15, 2001 and is not expected to have a material impact on our financial statements upon adoption on January 1, 2002.

#### ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We have significant long-term coal supply agreements. Virtually all of the long-term coal supply agreements are subject to price adjustment provisions, which permit an increase or decrease periodically in the contract price to principally reflect changes in specified price indices or items such as taxes, royalties or actual production costs. For additional discussion of coal supply agreements, see "Item 1. Business. – Coal Marketing and Sales" and "Item 8. Financial Statements and Supplementary Data. – Note 16. Concentration of Credit Risk and Major Customers."

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

We do not engage in any interest rate, foreign currency exchange rate or commodity price-hedging transactions.

The intermediate partnership assumed obligations under the Credit Facility. Borrowings under the Credit Facility are at variable rates and as a result we have interest rate exposure.

The table below provides information about our market sensitive financial instruments and constitutes a "forward-looking statement." The fair values of long-term debt are estimated using discounted cash flow analyses, based upon our current incremental borrowing rates for similar types of borrowing arrangements as of December 31, 2001, and 2000. The carrying amounts and fair values of financial instruments are as follows (in thousands):

Expected Maturity Dates as of December 31, 2001	2002	2003	2004	2005	2006	Thereafter	Total	Fair Value	
								December 31, 2001	
Senior Notes-fixed rate	\$ -	\$ -	\$ -	\$ 18,000	\$ 18,000	\$ 144,000	\$ 180,000	\$	180,000
Weighted Average interest rate				8.31%	8.31%	8.31%			
Term Loan-floating rate	\$ 15,000	\$ 16,250	\$ 15,000	\$ -		\$ -	\$ 46,250	\$	46,250
Weighted Average interest rate	3.40%	3.40%	3.40%						
Expected Maturity Dates as of December 31, 2000	2001	2002	2003	2004	2005	Thereafter	Total	Fair Value	
								December 31, 2000	
Senior Notes-fixed rate	\$ -	\$ -	\$ -	\$ -	\$ 18,000	\$ 162,000	\$ 180,000	\$	180,000
Weighted Average interest rate					8.31%	8.31%			
Term Loan-floating rate	\$ 3,750	\$ 15,000	\$ 16,250	\$ 15,000	\$ -	\$ -	\$ 50,000	\$	50,000
Weighted Average interest rate	7.77%	7.77%	7.77%	7.77%					

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### INDEPENDENT AUDITORS' REPORT

To the Board of Directors of the Managing  
General Partner and the Partners of  
Alliance Resource Partners, L.P.:

We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2001 and 2000, the related consolidated and combined statements of income and cash flows for the years ended December 31, 2001 and 2000, the period from the Partnership's commencement of operations (on August 20, 1999) to December 31, 1999, and the Predecessor period from January 1, 1999 to August 19, 1999, and the statement of Partners' capital (deficit) for the years ended December 31, 2001 and 2000, and the period from the Partnership's commencement of operations (on August 20, 1999) to December 31, 1999. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated and combined financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2001 and 2000 and the results of their operations and their cash flows for the years ended December 31, 2001 and 2000, the period from the Partnership's commencement of operations (on August 20, 1999) to December 31, 1999, and the Predecessor period from January 1, 1999 to August 19, 1999 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated and combined financial statements, the Partnership changed its method of estimating coal workers pneumoconiosis benefits liability effective January 1, 2001.

*/s/ Deloitte & Touche LLP*

Tulsa, Oklahoma  
January 28, 2002, except for Note 15  
as to which the date is March 14, 2002

# ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

## CONSOLIDATED BALANCE SHEETS DECEMBER 31, 2001 AND 2000 (In thousands, except unit data)

ASSETS	December 31,	
	2001	2000
<b>CURRENT ASSETS:</b>		
Cash and cash equivalents	\$ 9,176	\$ 6,933
Trade receivables, less allowance of \$763 and \$0, respectively	31,124	35,898
Due from affiliates	-	208
Marketable securities (at cost, which approximates fair value)	10,085	37,398
Inventories	11,600	10,842
Advance royalties	5,353	2,865
Prepaid expenses and other assets	2,020	1,168
Total current assets	69,358	95,312
PROPERTY, PLANT AND EQUIPMENT, AT COST	367,050	320,445
LESS ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION	(169,960)	(135,782)
	197,090	184,663
<b>OTHER ASSETS:</b>		
Advance royalties	9,756	10,009
Coal supply agreements, net	12,031	16,324
Other long-term assets	2,670	2,858
	\$ 290,905	\$ 309,166
 <b>LIABILITIES AND PARTNERS' EQUITY</b>		
<b>CURRENT LIABILITIES:</b>		
Accounts payable	\$ 25,237	\$ 25,558
Due to affiliates	2,595	-
Accrued taxes other than income taxes	5,660	4,863
Accrued payroll and related expenses	8,284	6,975
Accrued interest	5,402	5,439
Workers' compensation and pneumoconiosis benefits	4,194	4,415
Other current liabilities	5,324	5,710
Current maturities, long-term debt	15,000	3,750
Total current liabilities	71,696	56,710
<b>LONG-TERM LIABILITIES:</b>		
Long-term debt, excluding current maturities	211,250	226,250
Pneumoconiosis benefits	14,615	21,651
Workers' compensation	18,409	16,748
Reclamation and mine closing	15,387	14,940
Due to affiliates	3,624	1,278
Other liabilities	2,865	3,376
Total liabilities	337,846	340,953
<b>COMMITMENTS AND CONTINGENCIES</b>		
<b>PARTNERS' CAPITAL (DEFICIT):</b>		
Common Unitholders 8,982,780 units outstanding	141,448	149,642
Subordinated Unitholder 6,422,531 units outstanding	110,935	116,794
General Partners	(298,510)	(298,223)
Minimum pension liability	(814)	-
Total Partners' capital (deficit)	(46,941)	(31,787)
	\$ 290,905	\$ 309,166

See notes to consolidated and combined financial statements.

## ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED AND COMBINED STATEMENTS OF INCOME  
FOR THE YEARS ENDED DECEMBER 31, 2001 AND 2000, AND THE PERIOD FROM THE PARTNERSHIP'S  
COMMENCEMENT OF OPERATIONS (ON AUGUST 20, 1999) TO DECEMBER 31, 1999,  
AND THE PREDECESSOR PERIOD FROM JANUARY 1, 1999 TO AUGUST 19, 1999  
(In thousands, except unit and per unit data)

	Partnership			Predecessor
	Year Ended December 31,		From Commencement of Operations (on August 20, 1999) to December 31, 1999	For the period from January 1, 1999 to August 19, 1999
	2001	2000		
SALES AND OPERATING REVENUES:				
Coal sales	\$ 421,996	\$ 347,209	\$ 128,860	\$217,033
Transportation revenues	18,090	13,511	4,907	14,223
Other sales and operating revenues	6,214	2,749	358	577
Total revenues	<u>446,300</u>	<u>363,469</u>	<u>134,125</u>	<u>231,833</u>
EXPENSES:				
Operating expenses	307,977	257,365	89,945	152,066
Transportation expenses	18,090	13,511	4,907	14,223
Outside purchases	31,840	16,874	6,429	17,738
General and administrative	17,728	15,176	6,245	8,912
Depreciation, depletion and amortization	45,451	39,141	15,081	24,622
Interest expense (net of interest income and interest capitalized of \$1,928, \$3,015 and \$999 for the Partnership's respective periods)	16,805	16,563	5,887	100
Unusual items	-	(9,466)	-	-
Total operating expenses	<u>437,891</u>	<u>349,164</u>	<u>128,494</u>	<u>217,661</u>
INCOME FROM OPERATIONS	8,409	14,305	5,631	14,172
OTHER INCOME	752	1,276	641	531
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	9,161	15,581	6,272	14,703
INCOME TAX EXPENSE	-	-	-	4,498
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	9,161	15,581	6,272	\$ 10,205
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	7,939	-	-	-
NET INCOME	<u>\$ 17,100</u>	<u>\$ 15,581</u>	<u>\$ 6,272</u>	<u>\$ 10,205</u>
GENERAL PARTNERS' INTEREST IN NET INCOME	<u>\$ 342</u>	<u>\$ 312</u>	<u>\$ 125</u>	
LIMITED PARTNERS' INTEREST IN NET INCOME	<u>\$ 16,758</u>	<u>\$ 15,269</u>	<u>\$ 6,147</u>	
BASIC NET INCOME PER LIMITED PARTNER UNIT	<u>\$ 1.09</u>	<u>\$ 0.99</u>	<u>\$ 0.40</u>	
BASIC NET INCOME PER LIMITED PARTNER UNIT BEFORE ACCOUNTING CHANGE	<u>\$ 0.58</u>	<u>\$ 0.99</u>	<u>\$ 0.40</u>	
DILUTED NET INCOME PER LIMITED PARTNER UNIT	<u>\$ 1.07</u>	<u>\$ 0.98</u>	<u>\$ 0.40</u>	
DILUTED NET INCOME PER LIMITED PARTNER UNIT BEFORE ACCOUNTING CHANGE	<u>\$ 0.57</u>	<u>\$ 0.98</u>	<u>\$ 0.40</u>	
PRO FORMA NET INCOME ASSUMING ACCOUNTING CHANGE IS APPLIED RETROACTIVELY	<u>\$ 17,100</u>	<u>\$ 14,907</u>	<u>\$ 6,395</u>	<u>\$ 10,071</u>
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING - BASIC	<u>15,405,311</u>	<u>15,405,311</u>	<u>15,405,311</u>	
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING - DILUTED	<u>15,684,550</u>	<u>15,551,062</u>	<u>15,405,311</u>	

See notes to consolidated and combined financial statements.

# ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

**CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS**  
**FOR THE YEARS ENDED DECEMBER 31, 2001 AND 2000, THE PERIOD FROM THE PARTNERSHIP'S**  
**COMMENCEMENT OF OPERATIONS (ON AUGUST 20, 1999) TO DECEMBER 31, 1999, AND**  
**THE PREDECESSOR PERIOD FROM JANUARY 1, 1999 TO AUGUST 19, 1999**  
(In thousands)

	Partnership			Predecessor
	Year Ended December 31,		From Commencement of Operations (on August 20, 1999) to December 31, 1999	For the period from January 1, 1999 to August 19, 1999
	2001	2000		
<b>CASH FLOWS FROM OPERATING ACTIVITIES:</b>				
Net income	\$ 17,100	\$ 15,581	\$ 6,272	\$ 10,205
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	45,451	39,141	15,081	24,622
Cumulative effect of accounting change	(7,939)	-	-	-
Impairment of transloading facility	-	2,439	-	-
Deferred income taxes	-	-	-	639
Reclamation and mine closings	943	1,074	348	457
Coal inventory adjustment to market	212	579	729	-
Other	(257)	391	186	(114)
Changes in operating assets and liabilities:				
Trade receivables	4,774	(2,842)	(33,048)	(6,521)
Income tax receivable/payable	-	-	-	651
Inventories	(970)	9,709	(1,433)	(371)
Advance royalties	(2,235)	(3,011)	366	1,153
Accounts payable	(321)	6,181	(7,410)	(129)
Due to affiliates	5,149	264	3,252	-
Accrued taxes other than income taxes	797	289	(630)	678
Accrued payroll and related benefits	1,309	(1,836)	844	(828)
Accrued pneumoconiosis benefits	903	(4)	(1,122)	544
Workers' compensation	1,661	1,052	2,222	(460)
Other	(2,926)	2,366	452	2,370
Total net adjustments	<u>46,551</u>	<u>55,792</u>	<u>(20,163)</u>	<u>22,691</u>
Net cash provided by (used in) operating activities	<u>63,651</u>	<u>71,373</u>	<u>(13,891)</u>	<u>32,896</u>
<b>CASH FLOWS FROM INVESTING ACTIVITIES:</b>				
Purchase of property, plant and equipment	(53,714)	(46,151)	(17,173)	(21,984)
Proceeds from sale of property, plant and equipment	183	210	125	447
Purchase of marketable securities	(33,527)	(72,523)	(51,287)	-
Proceeds from the maturity of marketable securities	<u>60,840</u>	<u>77,464</u>	<u>24,434</u>	<u>-</u>
Net cash used in investing activities	<u>(26,218)</u>	<u>(41,000)</u>	<u>(43,901)</u>	<u>(21,537)</u>
<b>CASH FLOWS FROM FINANCING ACTIVITIES:</b>				
Net proceeds from initial public offering (Note 1)	-	-	137,872	-
Cash contribution by General Partner	-	-	5,917	-
Distributions upon formation (Note 1)	-	-	(64,750)	-
Payment of formation costs	-	-	(4,140)	-
Deferred financing cost	-	-	(3,517)	-
Borrowings under revolving credit facility	1,100	29,500	-	-
Payments under revolving credit facility	(1,100)	(29,500)	-	-
Payments on long-term debt	(3,750)	-	(1,975)	-
Distributions to Partners	(31,440)	(31,440)	(3,615)	-
Return of capital to Parent	-	-	-	(11,359)
Net cash provided by (used in) financing activities	<u>(35,190)</u>	<u>(31,440)</u>	<u>65,792</u>	<u>(11,359)</u>
<b>NET CHANGE IN CASH AND CASH EQUIVALENTS</b>	<b>2,243</b>	<b>(1,067)</b>	<b>8,000</b>	<b>-</b>
<b>CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD</b>	<b><u>6,933</u></b>	<b><u>8,000</u></b>	<b><u>-</u></b>	<b><u>-</u></b>
<b>CASH AND CASH EQUIVALENTS AT END OF PERIOD</b>	<b><u>\$ 9,176</u></b>	<b><u>\$ 6,933</u></b>	<b><u>\$ 8,000</u></b>	<b><u>\$ -</u></b>

See notes to consolidated and combined financial statements.

## ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

**CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL (DEFICIT)**  
**FOR THE YEARS ENDED DECEMBER 31, 2001 AND 2000, AND THE PERIOD FROM THE PARTNERSHIP'S**  
**COMMENCEMENT OF OPERATIONS (ON AUGUST 20, 1999) TO DECEMBER 31, 1999**  
**(In thousands, except unit data)**

	Number of Limited Partner Units		Common	Subordinated	General Partners	Minimum Pension Liability	Total Partners' Capital (Deficit)
	Common	Subordinated					
Balance at commencement of operations (on August 20, 1999)	-	-	\$ -	\$ 1	\$ -	\$ -	\$ 1
Issuance of units to public	7,750,000	-	133,732	-	-	-	133,732
Contribution of net assets of Predecessor	1,232,780	6,422,531	23,455	122,186	(24,612)	(459)	120,570
Managing General Partner contribution	-	-	-	-	5,917	-	5,917
Amount retained by Special General Partner from debt borrowings assumed by the Partnership	-	-	-	-	(214,514)	-	(214,514)
Distribution at time of formation	-	-	-	-	(64,750)	-	(64,750)
Distribution to Partners	-	-	(2,066)	(1,477)	(72)	-	(3,615)
Comprehensive income:							
Net income from commencement of operations (on August 20, 1999) to December 31, 1999	-	-	3,584	2,563	125	-	6,272
Minimum pension liability	-	-	-	-	-	459	459
Total comprehensive income	-	-	<u>3,584</u>	<u>2,563</u>	<u>125</u>	<u>459</u>	<u>6,731</u>
Balance at December 31, 1999	8,982,780	6,422,531	158,705	123,273	(297,906)	-	(15,928)
Net income	-	-	8,903	6,366	312	-	15,581
Distribution to Partners	-	-	<u>(17,966)</u>	<u>(12,845)</u>	<u>(629)</u>	-	<u>(31,440)</u>
Balance at December 31, 2000	8,982,780	6,422,531	149,642	116,794	(298,223)	-	(31,787)
Comprehensive income:							
Net income	-	-	9,772	6,986	342	-	17,100
Minimum pension liability	-	-	-	-	-	(814)	(814)
Total comprehensive income	-	-	9,772	6,986	342	(814)	16,286
Distribution to Partners	-	-	<u>(17,966)</u>	<u>(12,845)</u>	<u>(629)</u>	-	<u>(31,440)</u>
Balance at December 31, 2001	<u>8,982,780</u>	<u>6,422,531</u>	<u>\$141,448</u>	<u>\$110,935</u>	<u>\$(298,510)</u>	<u>\$(814)</u>	<u>\$(46,941)</u>

See notes to consolidated and combined financial statements.

## ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

### NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2001 AND 2000, AND THE PERIOD FROM THE PARTNERSHIP'S COMMENCEMENT OF OPERATIONS (ON AUGUST 20, 1999) TO DECEMBER 31, 1999, AND THE PREDECESSOR PERIOD FROM JANUARY 1, 1999 TO AUGUST 19, 1999

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#### 1. ORGANIZATION AND PRESENTATION

Alliance Resource Partners, L.P., a Delaware limited partnership (the "Partnership") was formed on May 17, 1999, to acquire, own and operate certain coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation ("ARH") (formerly known as Alliance Coal Corporation), consisting of substantially all of ARH's operating subsidiaries, but excluding ARH.

Prior to August 20, 1999, (a) MAPCO Coal Inc., a Delaware corporation and direct wholly-owned subsidiary of ARH merged with and into Alliance Coal, LLC, a Delaware limited liability company ("Alliance Coal"), which prior to August 20, 1999 was also a wholly-owned subsidiary of ARH, (b) several other indirect corporate subsidiaries of ARH were merged with and into corresponding limited liability companies, each of which is a wholly-owned subsidiary of Alliance Coal, and (c) two indirect limited liability company subsidiaries of ARH became subsidiaries of Alliance Coal as a result of the merger described in clause (a) above. Collectively, the coal production and marketing assets and operating subsidiaries of ARH acquired by the Partnership, but excluding ARH, are referred to as the Alliance Resource Group (the "Predecessor"). The Delaware limited partnerships and limited liability companies and corporation that comprise the Partnership are as follows: Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. (the "Intermediate Partnership"), Alliance Coal, LLC (the holding company for operations), Alliance Land, LLC, Alliance Properties, LLC, Alliance Service, Inc., Backbone Mountain, LLC, Excel Mining, LLC, Gibson County Coal, LLC, Hopkins County Coal, LLC, MC Mining, LLC, Mettiki Coal, LLC, Mettiki Coal (WV), LLC, Mt. Vernon Transfer Terminal, LLC, Pontiki Coal, LLC, Webster County Coal, LLC, and White County Coal, LLC.

The accompanying consolidated financial statements include the accounts and operations of the limited partnerships and limited liability companies disclosed above and present the financial position as of December 31, 2001 and 2000 and the results of their operations, cash flows and changes in partners' capital (deficit) for the years ended December 31, 2001 and 2000 and the period from commencement of operations on August 20, 1999 to December 31, 1999. The accompanying combined financial statements include the accounts and operations of the Predecessor for the period indicated. All material intercompany transactions and accounts of the Partnership and Predecessor have been eliminated.

#### *Initial Public Offering and Concurrent Transactions*

On August 20, 1999, the Partnership completed its initial public offering (the "IPO") of 7,750,000 Common Units ("Common Units") representing limited partner interests in the Partnership at a price of \$19.00 per unit.

Concurrently with the closing of the IPO, the Partnership entered into a contribution and assumption agreement (the "Contribution Agreement") dated August 20, 1999 among the Partnership and the other parties named therein, whereby, among other things, ARH contributed its 100% member interest in Alliance Coal, which is the sole member of thirteen subsidiary operating limited liability companies, to the Intermediate Partnership, and the Intermediate Partnership holds a 99.999% non-managing member interest in Alliance Coal. The Partnership and the Intermediate Partnership are managed by Alliance

Resource Management GP, LLC, a Delaware limited liability company (the "Managing GP"), which as a result of the consummation of the transactions under the Contribution Agreement, holds (a) a 0.99% and 1.0001% managing general partner interest in the Partnership and the Intermediate Partnership, respectively, and (b) a 0.001% managing member interest in Alliance Coal. Also, as a result of the consummation of the transactions completed under the Contribution Agreement, Alliance Resource GP, LLC, a Delaware limited liability company and wholly-owned subsidiary of ARH (the "Special GP"), holds (a) 1,232,780 Common Units, (b) 6,422,531 Subordinated Units convertible into Common Units in the future upon the occurrence of certain events and (c) a 0.01% special general partner interest in each of the Partnership and the Intermediate Partnership.

Concurrently with the closing of the IPO, the Special GP issued and the Intermediate Partnership assumed the obligations under a \$180 million principal amount of 8.31% senior notes due August 20, 2014. The Special GP also entered into and the Intermediate Partnership assumed the obligations under a \$100 million credit facility.

Consistent with guidance provided by the Emerging Issues Task Force in Issue No. 87-21, "Change of Accounting Basis in Master Limited Partnership Transactions," the Partnership maintained the historical cost basis of the \$121 million of net assets received under the Contribution Agreement.

#### *Pro Forma Results of Operations (Unaudited)*

For the year ended December 31, 1999, the pro forma total revenues would have been approximately \$346,828,000, the pro forma net income would have been approximately \$7,567,000 and net income per limited partner unit would have been \$0.48. The pro forma results of operations are derived from the historical financial statements of the Partnership from the commencement of operations on August 20, 1999 through December 31, 1999 and the Predecessor for the period from January 1, 1999 through August 19, 1999. The pro forma results of operations reflect certain pro forma adjustments to the historical results of operations as if the Partnership had been formed on January 1, 1999. The pro forma adjustments include pro forma interest on debt assumed by the Partnership and the elimination of income tax expense as income taxes will be borne by the partners and not the Partnership.

## **2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

*Estimates* – The preparation of consolidated and combined financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated and combined financial statements. Actual results could differ from those estimates.

*Fair Value of Financial Instruments* – The carrying amounts for accounts receivable, marketable securities, and accounts payable approximate fair value because of the short maturity of those instruments. At December 31, 2001 and 2000, the estimated fair value of long-term debt was approximately \$226 million and \$230 million, respectively. The fair value of long-term debt is based on interest rates that are currently available to the Partnership for issuance of debt with similar terms and remaining maturities.

*Cash and Cash Equivalents* – Cash and cash equivalents include cash on hand and on deposit, including highly liquid investments with maturities of three months or less.

*Cash Management* – The Partnership reclassified outstanding checks of \$3,352,000 and \$4,698,000 at December 31, 2001 and 2000, respectively, to accounts payable in the consolidated balance sheets.

*Marketable Securities* – At December 31, 2001, the Partnership has an investment in a Federal Agency Note, which matures February 1, 2002 and is classified as an available-for-sale security. At December 31, 2000, the Partnership had investments in six-month U.S. Treasury Notes that were classified as available-for-sale securities. At December 31, 2001 and 2000, the cost of marketable securities approximates fair value and no effect of unrealized gains (losses) is reflected in Partners' capital (deficit).

*Inventories* – Coal inventories are stated at the lower of cost or market on a first-in, first-out basis. Supply inventories are stated at the lower of cost or market on an average cost basis.

*Property, Plant and Equipment* – Additions and replacements constituting improvements are capitalized. Maintenance, repairs, and minor replacements are expensed as incurred. Depreciation and amortization are computed principally on the straight-line method based upon the estimated useful lives of the assets or the estimated life of each mine, whichever is less ranging from 5 to 20 years. Depreciable lives for mining equipment and processing facilities range from 2 to 20 years. Depreciable lives for land and land improvements and depletable lives for mineral rights range from 5 to 20 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 20 years. Gains or losses arising from retirements are included in current operations. Depletion of mineral rights is provided on the basis of tonnage mined in relation to estimated recoverable tonnage. At December 31, 2001 and 2000, land and mineral rights include \$2,178,000 representing the carrying value of coal reserves attributable to properties where the Partnership is not currently engaged in mining operations or leasing to third parties, and therefore, the coal reserves are not currently being depleted.

*Long-Lived Assets* – The Partnership reviews the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. The amount of an impairment is measured by the difference between the carrying value and the fair value of the asset, which is based on cash flows from that asset, discounted at a rate commensurate with the risk involved. During 2000, the Partnership recorded an impairment loss of approximately \$2,439,000 relating to certain transloading facility assets, associated with Seminole Electric Cooperative, Inc.'s ("Seminole") termination of a long-term contract for transloading of coal from rail to barge. Because this facility's revenues were primarily attributable to the Seminole long-term contract, the carrying value of the transloading facility and associated equipment, net of salvage value, was recorded as an impairment and is included as an unusual item in 2000 in the accompanying consolidated and combined statements of income.

*Advance Royalties* – Rights to coal mineral leases are often acquired through advance royalty payments. Management assesses the recoverability of royalty prepayments based on estimated future production and capitalizes these amounts accordingly. Royalty prepayments expected to be recouped within one year are classified as a current asset. As mining occurs on those leases, the royalty prepayments are included in the cost of mined coal. Royalty prepayments estimated to be nonrecoverable are expensed.

*Coal Supply Agreements* – The Predecessor purchased the coal operations of MAPCO Inc. effective August 1, 1996, in a business combination using the purchase method of accounting. A portion of the acquisition costs was allocated to coal supply agreements. This allocated cost is being amortized on the basis of coal shipped in relation to total coal to be supplied during the respective contract terms. The amortization periods end on various dates from September 2002 to December 2005. Accumulated amortization for coal supply agreements was \$26,432,000 and \$22,139,000 at December 31, 2001 and 2000, respectively.

*Reclamation and Mine Closing Costs* – The liability for the estimated cost of future mine reclamation and closing procedures is recorded on a present value basis when incurred and the associated cost is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to sealing portals at underground mines and to reclaiming the final pit and support acreage at surface mines. Other costs common to both types of mining are related to removing or covering refuse piles and settling ponds, and dismantling preparation plants, other facilities and roadway infrastructure. Ongoing reclamation costs principally involve restoration of disturbed land and are expensed as incurred during the mining process.

*Workers' Compensation and Pneumoconiosis ("Black Lung") Benefits* – The Partnership is self-insured for workers' compensation benefits, including black lung benefits. The Partnership accrues a workers' compensation liability for the estimated present value of workers' compensation and black lung benefits based on actuarial valuations. Effective January 1, 2001, the Partnership changed its method of estimating the black lung benefits liability (Note 3).

*Income Taxes* – No provision for income taxes related to the operations of the Partnership is included in the accompanying consolidated financial statements because, as a Partnership, it is not subject to federal or state income tax and the tax effect of its activities accrues to the unitholders. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership agreement.

The Predecessor was included in the combined U.S. income tax returns of ARH. The Predecessor provided for income taxes on its separate taxable income and other tax attributes. Deferred income taxes are computed based on recognition of future tax expense or benefits, measured by enacted tax rates that are attributable to taxable or deductible temporary differences between financial statement and income tax reporting bases of assets and liabilities.

*Revenue Recognition* – Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Non-coal sales revenues primarily consist of fees associated with agreements to host and operate a third-party coal synfuel facility and assist with the coal synfuel marketing and other related services. These non-coal sales revenues are recognized as the services are performed. Transportation revenues are recognized in connection with the Partnership incurring the corresponding costs of transporting the coal to customers through third-party carriers since the Partnership is directly reimbursed for these costs through customer billings.

*Net Income Per Unit* – Basic net income per limited partner unit is determined by dividing net income, after deducting the General Partners' 2% interest, by the weighted average number of outstanding Common Units and Subordinated Units (a total of 15,405,311 units as of December 31, 2001 and 2000). Diluted net income per unit is based on the combined weighted average number of Common Units, Subordinated Units and common unit equivalents outstanding, which primarily include restricted units granted under the Long-Term Incentive Plan (Note 11).

*Segment Reporting* – The Partnership has no reportable segments due to its operations consisting solely of producing and marketing coal. The Partnership has disclosed major customer sales information (Note 16) and geographic areas of operation (Note 17).

*New Accounting Standards* – Effective January 1, 2001, the Partnership adopted Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," which establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires that all derivatives be recognized as either assets or liabilities in the

statement of financial position and be measured at fair value. The Partnership currently has no identified derivative instruments or hedging activities. Accordingly, this standard had no effect on the Partnership's consolidated financial statements upon adoption.

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations" and No. 142 "Goodwill and Intangible Assets." SFAS No. 141 eliminates the pooling-of-interests method of accounting for business combinations and requires that all business combinations be accounted for under the purchase method. In addition, it further clarifies the criteria for recognition of intangible assets separately from goodwill. This statement is effective for business combinations initiated after June 30, 2001. SFAS No. 142 discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. This statement is effective January 1, 2002, for all goodwill and other intangible assets included in an entity's statement of financial position at that date, regardless of when those assets were initially recognized. SFAS 141 and 142 are not expected to have a material impact on the Partnership's financial statements.

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred. When the liability is initially recorded, a cost is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. To settle the liability, the obligation for its recorded amount is paid or a gain or loss upon settlement is incurred. Since the Partnership has historically adhered to accounting principles similar to SFAS No. 143 in accounting for its reclamation and mine closing costs, the Partnership does not believe that adoption of SFAS No. 143, effective January 1, 2003, will have a material impact on its financial statements.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which is effective for fiscal years beginning after December 15, 2001, and is not expected to have a material impact on the Partnership's financial statements upon adoption on January 1, 2002.

*Reclassifications* – Certain reclassifications have been made to the 1999 combined and consolidated financial statements to conform to the classifications used in 2001 and 2000.

### 3. ACCOUNTING CHANGE

The Partnership changed its method of estimating coal workers' pneumoconiosis ("black lung") benefits liability effective January 1, 2001 to the service cost method described in SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," which method is permitted under SFAS No. 112 "Employers' Accounting for Postemployment Benefits." The Partnership previously accrued the black lung benefits liability at the present value of the actuarially determined current and future estimated black lung benefit payments utilizing the methodology prescribed under SFAS No. 5 "Accounting for Contingencies," which was also permitted by SFAS No. 112. Recently, governmental regulations regarding the black lung benefits claims approval process were enacted. These new regulations specifically define the black lung disability as progressive and also expand the definition of pneumoconiosis to mandate consideration of diseases that are caused by factors other than exposure to coal dust. The Partnership believes the change to the SFAS No. 106 measurement methodology better matches black lung costs over the service lives of the miners who ultimately receive the black lung benefits and is more reflective of the recently enacted regulations, which place significant emphasis on coal miners' future years of employment in the coal industry.

The adjustment of \$7,939,000 to apply retroactively the new method of estimating the black lung liability is included in net income for the year ended December 31, 2001. The effect of the change for the year ended December 31, 2001 was to decrease income before cumulative effect of a change in accounting principle \$435,000 (\$0.03 per basic and diluted limited partner unit) and increase net income \$7,504,000 (\$0.48 and \$0.47 per basic and diluted partner unit, respectively). Assuming the retroactive application of the service cost method of estimating the black lung liability, the pro forma net income for the year ended December 31, 2000, and the period from the Partnership's commencement of operations on August 20, 1999 to December 31, 1999, would have been approximately \$14,907,000 and \$6,395,000 or \$0.95 and \$0.41 per basic limited partner unit and \$0.94 and \$0.41 per diluted limited partner unit, respectively, as compared to reported net income of \$15,581,000 and \$6,272,000 or \$0.99 and \$0.40 per basic limited partner unit and \$0.98 and \$0.40 per diluted limited partner unit, respectively. Pro forma net income for the Predecessor period from January 1, 1999 to August 19, 1999 would have been \$10,071,000 compared to reported net income of \$10,205,000.

#### 4. UNUSUAL ITEMS

The Partnership was involved in litigation with Seminole with respect to Seminole's termination of a long-term contract for the transloading of coal from rail to barge through the Mt. Vernon terminal in Indiana. The final resolution between the parties, reached in conjunction with an arbitrator's decision rendered during the third quarter of 2000, included both cash payments and amendments to an existing coal supply contract. The Partnership recorded income of \$12,141,000, which is net of litigation expenses of approximately \$881,000 and an impairment charge of \$2,439,000 relating to the facility's assets. Additionally, during the third quarter of 2000, the Partnership recorded an expense of \$2,675,000, consisting of \$675,000 relating to a settlement and \$2,000,000 attributable to contingencies associated with third party claims arising out of the Partnership's mining operations. The net effect of these unusual items is \$9,466,000 recorded in the year ended December 31, 2000.

#### 5. INVENTORIES

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

	<u>2001</u>	<u>2000</u>
Coal	\$ 4,184	\$ 5,140
Supplies	<u>7,416</u>	<u>5,702</u>
	<u>\$ 11,600</u>	<u>\$ 10,842</u>

## 6. PROPERTY, PLANT AND EQUIPMENT

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

	<u>2001</u>	<u>2000</u>
Mining equipment and processing facilities	\$ 299,480	\$ 267,287
Land and mineral rights	17,691	17,686
Buildings, office equipment and improvements	29,359	24,224
Construction in progress	<u>20,520</u>	<u>11,248</u>
	367,050	320,445
Less accumulated depreciation, depletion and amortization	<u>(169,960)</u>	<u>(135,782)</u>
	<u>\$ 197,090</u>	<u>\$ 184,663</u>

## 7. LONG-TERM DEBT

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

	<u>2001</u>	<u>2000</u>
Senior notes	\$ 180,000	\$ 180,000
Term loan	<u>46,250</u>	<u>50,000</u>
	226,250	230,000
Less current maturities	<u>(15,000)</u>	<u>(3,750)</u>
	<u>\$ 211,250</u>	<u>\$ 226,250</u>

In connection with the closing of the IPO, the Special GP issued and the Intermediate Partnership assumed obligations with respect to a \$180 million principal amount of senior notes pursuant to a Note Purchase Agreement with a group of institutional investors in a private placement offering. The senior notes are payable in ten annual installments of \$18 million beginning in August 2005 and bear interest at 8.31%, payable semiannually.

The Special GP also entered into, and the Intermediate Partnership assumed obligations under, a \$100 million credit facility. The credit facility consists of three tranches, including a \$50 million term loan facility, a \$25 million working capital facility and a \$25 million revolving credit facility. In connection with the closing of the IPO, the Special GP borrowed \$50 million under the term loan facility and the Special GP and Intermediate Partnership initially purchased \$50 million of U.S. Treasury Notes, which secured the term loan through September 19, 2002. These investments were subject to certain provisions of the credit facility, which restricted the use of these investments for financing a required level of capital expenditures through August 2001. During 2001, the Partnership had satisfied the capital expenditure requirements and consequently, the Partnership's use of these investments was not restricted. The Partnership liquidated these investments during 2001. The Partnership has outstanding borrowings of \$46.3 million under the term loan facility at December 31, 2001.

The working capital facility can be used to provide working capital and, if necessary, to fund distributions to unitholders. The revolving credit facility can be used for general business purposes, including capital expenditures and acquisitions. The rate of interest charged is adjusted quarterly based on a pricing grid, which is a function of the ratio of the Partnership's debt to cash flow. The credit facility provides the Partnership the option of borrowing at either (1) the London Interbank Offered Rate

("LIBOR") or (2) the "Base Rate" which is equal to the greater of (a) the Chase Prime Rate, or (b) the Federal Funds Rate plus ½ of 1%, plus, in either option, an applicable margin. The weighted average interest rates on the term loan facility at December 31, 2001 and 2000 were 3.40% and 7.77%, respectively. In accordance with the pricing grid, a commitment fee ranging from 0.375% to 0.500% per annum is paid quarterly on the unused portion of the working capital and revolving credit facilities. There were no amounts outstanding under the Partnership's working capital facility or revolving credit facility as of December 31, 2001 and 2000. The credit facility expires in August 2004.

The senior notes and credit facility are guaranteed by all subsidiaries of the Intermediate Partnership. The senior notes and credit facility contain various restrictive and affirmative covenants, including limitations on the amount of distributions by the Intermediate Partnership and the incurrence of other debt. The Partnership was in compliance with the covenants of both the credit facility and senior notes at December 31, 2001 and 2000.

The Partnership incurred debt issuance costs aggregating approximately \$3,517,000, which have been deferred and are being amortized as a component of interest expense over the terms of the notes.

The Partnership entered into agreements with three banks to provide letters of credit in an aggregate amount of \$25.0 million. At December 31, 2001, the Partnership had \$15.0 million in letters of credit outstanding. The Special GP guarantees the letters of credit (Note 14).

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

Year Ending December 31,	
2002	\$ 15,000
2003	16,250
2004	15,000
2005	18,000
2006	18,000
Thereafter	<u>144,000</u>
	<u>\$ 226,250</u>

#### 8. DISTRIBUTIONS OF AVAILABLE CASH

The Partnership will distribute 100% of its available cash within 45 days after the end of each quarter to unitholders of record and to the General Partners. Available cash is generally defined as all cash and cash equivalents of the Partnership on hand at the end of each quarter less reserves established by the Managing GP in its reasonable discretion for future cash requirements. These reserves are retained to provide for the conduct of the Partnership's business, the payment of debt principal and interest and to provide funds for future distributions.

Distributions of available cash to the holder of Subordinated Units are subject to the prior rights of holders of Common Units to receive the minimum quarterly distribution ("MQD") for each quarter during the subordination period and to receive any arrearages in the distribution of the MQD on the Common Units for the prior quarters during the subordination period. The MQD is \$0.50 per unit (\$2.00 per unit on an annual basis). Upon expiration of the subordination period, which will generally not occur before September 30, 2004, all Subordinated Units will be converted on a one-for-one basis into Common Units and will then participate, on a pro rata basis with all other Common Units in future

distributions of available cash. However, under certain circumstances, up to 50% of the Subordinated Units may convert into Common Units on or after September 30, 2003. Common Units will accrue arrearages with respect to distributions for any quarter during the subordination period, but Subordinated Units will not accrue any arrearages with respect to distributions for any quarter.

If quarterly distributions of available cash exceed the MQD or the target distributions levels, the General Partners will receive distributions based on specified increasing percentages of the available cash that exceeds the MQD or target distribution levels. The target distribution levels are based on the amounts of available cash from the Partnership's operating surplus distributed for a given quarter that exceed distributions for the MQD and common unit arrearages, if any.

For the 42-day period from the Partnership's commencement of operations (on August 20, 1999) through September 30, 1999, the Partnership paid a pro-rata MQD distribution of \$0.23 per unit on its outstanding Common and Subordinated Units. For each of the quarters ended December 31, 1999 through September 30, 2001, quarterly distributions of \$0.50 per unit were paid to the common and subordinated unitholders. On January 29, 2002, the Partnership declared a MQD, for the period from October 1, 2001 to December 31, 2001, of \$0.50 per unit, totaling approximately \$7,703,000 on its outstanding Common and Subordinated Units, payable on February 14, 2002 to all unitholders of record on February 4, 2002.

#### 9. INCOME TAXES

The Predecessor recognized a deferred tax asset for the future tax benefits attributable to deductible temporary differences and other credit carryforwards, including alternative minimum tax credit carryforwards. Realization of these future tax benefits was dependent on the Predecessor's ability to generate future taxable income, which was not assured. Management of the Predecessor believed that future taxable income would be sufficient to recognize only a portion of the tax benefits and had established a valuation allowance.

Concurrent with the closing of the IPO on August 20, 1999, and in connection with the Contribution Agreement, ARH retained the current and deferred income taxes of the Predecessor.

Income before income taxes is derived from domestic operations. Significant components of income taxes are as follows (in thousands):

	For the period from January 1, 1999 to <u>August 19, 1999</u>
Current:	
Federal	\$ 3,376
State	<u>483</u>
	3,859
Deferred:	
Federal	595
State	<u>44</u>
	<u>639</u>
Income tax expense	<u>\$ 4,498</u>

A reconciliation of the statutory U.S. federal income tax rate and the Predecessor's effective income tax rate is as follows:

	For the period from January 1, 1999 to <u>August 19, 1999</u>
Statutory rate	35 %
Increase (decrease) resulting from:	
Excess of tax over book depletion	(21)
Alternative minimum tax credit carryforwards	3
State income taxes, net of federal benefit	3
Valuation allowance	10
Other	<u>1</u>
Effective income tax rate	<u>31 %</u>

#### 10. NET INCOME PER LIMITED PARTNER UNIT

A reconciliation of net income and weighted average units used in computing basic and diluted earnings per unit is as follows (in thousands, except per unit data):

	Year Ended December 31,		From Commencement of Operations (on August 20, 1999) to December 31, 1999
	<u>2001</u>	<u>2000</u>	
Net income per limited partner unit	\$ 16,758	\$ 15,269	\$ 6,147
Weighted average limited partner units - basic	15,405	15,405	15,405
Basic net income per limited partner unit	<u>\$ 1.09</u>	<u>\$ 0.99</u>	<u>\$ 0.40</u>
Basic net income per limited partner unit before accounting change	<u>\$ 0.58</u>	<u>\$ 0.99</u>	<u>\$ 0.40</u>
Weighted average limited partner units - basic	15,405	15,405	15,405
Units contingently issuable:			
Restricted units for Long-Term Incentive Plan	263	142	-
Directors' compensation units deferred	9	4	-
Supplemental Executive Retirement Plan	<u>8</u>	<u>-</u>	<u>-</u>
Weighted average limited partner units, assuming dilutive effect of restricted units	<u>15,685</u>	<u>15,551</u>	<u>15,405</u>
Diluted net income per limited partner unit	<u>\$ 1.07</u>	<u>\$ 0.98</u>	<u>\$ 0.40</u>
Diluted net income per limited partner unit before accounting change	<u>\$ 0.57</u>	<u>\$ 0.98</u>	<u>\$ 0.40</u>

## 11. EMPLOYEE BENEFIT PLANS

*Long-Term Incentive Plan* – Effective January 1, 2000, the Managing GP adopted the Long-Term Incentive Plan (the “LTIP”) for certain employees and directors of the Managing GP and its affiliates who perform services for the Partnership. Annual grant levels and vesting provisions for designated participants are recommended by the President and Chief Executive Officer of the Managing GP, subject to the review and approval of the Compensation Committee. Grants are made either of restricted units, which are “phantom” units that entitle the grantee to receive a Common Unit or an equivalent amount of cash upon the vesting of a phantom unit, or options to purchase Common Units. Common Units to be delivered upon the vesting of restricted units or to be issued upon exercise of a unit option will be acquired by the Managing GP in the open market at a price equal to the then prevailing price, or directly from ARH or any other third party, including units newly issued by the Partnership, units already owned by the Managing GP, or any combination of the foregoing. The Partnership agreement provides that the Managing GP be reimbursed for all costs incurred in acquiring these Common Units or in paying cash in lieu of Common Units upon vesting of the restricted units. The aggregate number of units reserved for issuance under the LTIP is 600,000. Effective January 1, 2000 and 2001 the Compensation Committee approved grants of 142,100 and 129,200 restricted units, respectively, which vest at the end of the subordination period, which will generally not end before September 30, 2004. During 2001, 8,500 units were forfeited. During 2001 and 2000, the Managing GP billed the Partnership approximately \$1,929,000 and \$538,000, respectively, attributable to the LTIP. The Partnership has recorded this amount as compensation expense. Effective January 1, 2002, the Compensation Committee approved additional grants of 131,885 restricted units, which also vest at the end of the subordination period.

*Defined Contribution Plans* – The Partnership’s employees currently participate in a defined contribution profit sharing and savings plan sponsored by the Partnership, which is the same plan sponsored by the Predecessor. This plan covers substantially all full-time employees. Plan participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. The Partnership makes contributions based on matching 75% of employee contributions up to 3% of their annual compensation as well as an additional nonmatching contribution of  $\frac{3}{4}$  of 1% of their compensation. Additionally, the Partnership contributes a defined percentage of eligible earnings for certain employees not covered by the defined benefit plan described below. The Partnership’s expense for its plan was approximately \$1,935,000 and \$1,590,000 for the years ended December 31, 2001 and 2000, respectively, and \$715,000 for the period from August 20, 1999 to December 31, 1999. The Predecessor’s expense for the plan was \$1,226,000 for the period from January 1, 1999 to August 19, 1999.

*Defined Benefit Plans* – Certain employees at the mining operations participate in a defined benefit plan sponsored by the Partnership, which is the same plan sponsored by the Predecessor. The benefit formula is a fixed dollar unit based on years of service.

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2001 and 2000 and the funded status of the plans reconciled with amounts reported in the Partnership's consolidated financial statements at December 31, 2001 and 2000, respectively (dollars in thousands):

	<u>2001</u>	<u>2000</u>
<b>Change in benefit obligations:</b>		
Benefit obligations at beginning of year	\$ 10,135	\$ 7,774
Service cost	2,050	1,971
Interest cost	755	596
Actuarial (gain) loss	384	(136)
Benefits paid	<u>(122)</u>	<u>(70)</u>
Benefit obligation at end of year	<u>13,202</u>	<u>10,135</u>
<b>Change in plan assets:</b>		
Fair value of plan assets at beginning of year	9,500	8,265
Employer contribution	1,500	1,100
Actual return (loss) on plan assets	(370)	205
Benefits paid	<u>(122)</u>	<u>(70)</u>
Fair value of plan assets at end of year	<u>10,508</u>	<u>9,500</u>
Funded status	(2,694)	(635)
Unrecognized prior service cost	235	284
Unrecognized actuarial (gain) loss	<u>814</u>	<u>(828)</u>
Net amount recognized	<u>\$ (1,645)</u>	<u>\$ (1,179)</u>
<b>Weighted-average assumptions as of December 31:</b>		
Discount rate	7.25 %	7.50 %
Expected return on plan assets	9.00 %	9.00 %
<b>Components of net periodic benefit cost:</b>		
Service cost	\$ 2,050	\$ 1,971
Interest cost	755	596
Expected return on plan assets	(888)	(737)
Prior service cost	48	48
Net gain	<u>-</u>	<u>(49)</u>
Net periodic benefit cost	<u>\$ 1,965</u>	<u>\$ 1,829</u>
Effect on minimum pension liability	<u>\$ 814</u>	<u>\$ -</u>

## 12. RECLAMATION AND MINE CLOSING COSTS

The majority of the Partnership's operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations, among other requirements, require restoration of property in accordance with specified standards and an approved reclamation plan. The Partnership has estimated the costs and timing of future reclamation and mine closing costs and recorded those estimates on a present value basis using a 6% discount rate.

Discounting resulted in reducing the accrual for reclamation and mine closing costs by \$12,184,000 and \$10,420,000 at December 31, 2001 and 2000, respectively. Estimated payments of reclamation and mine closing costs as of December 31, 2001 are as follows (in thousands):

Year Ending December 31,	
2002	\$ 1,078
2003	1,743
2004	1,848
2005	3,538
2006	2,518
Thereafter	<u>17,924</u>
Aggregate undiscounted reclamation and mine closing	28,649
Effect of discounting	<u>12,184</u>
Total reclamation and mine closing costs	16,465
Less current portion	<u>1,078</u>
Reclamation and mine closing costs	<u>\$ 15,387</u>

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

	Partnership		From Commencement of Operations (on August 20, 1999) to December 31, 1999	Predecessor
	Year Ended December 31,			For the period from
	2001	2000		January 1, 1999 to August 19, 1999
Beginning balance	\$ 16,018	\$ 14,796	\$ 13,856	\$ 13,800
Accrual	943	1,074	348	457
Payments	(454)	(764)	(394)	(401)
Allocation of liability associated with acquisition and mine development	<u>(42)</u>	<u>912</u>	<u>986</u>	<u>-</u>
Ending balance	<u>\$ 16,465</u>	<u>\$ 16,018</u>	<u>\$ 14,796</u>	<u>\$ 13,856</u>

### 13. PNEUMOCONIOSIS ("BLACK LUNG") BENEFITS

Certain mine operating entities of the Partnership are liable under state statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay black lung benefits to eligible employees and former employees and their dependents.

The Partnership changed its method of estimating black lung benefits liability effective January 1, 2001 to the service cost method (Note 3). Under the service cost method the calculation of the actuarial present value of the estimated black lung obligation is based on an actuarial study performed by independent actuaries. Actuarial gains or losses are amortized over the remaining service period of

active miners. The discount rate used to calculate the estimated present value of future obligations was 5.5% and 6.0% at December 31, 2001 and 2000, respectively.

The reconciliation of changes in benefit obligations at December 31, 2001 is as follows (in thousands):

Benefit obligations at beginning of year, including cumulative effect of accounting change of \$7,939 effective January 1, 2001 (Note 3)	\$ 13,712
Service cost	464
Interest cost	705
Benefits paid	<u>(266)</u>
 Benefit obligations at end of year	 <u>\$ 14,615</u>

The Partnership previously accrued the black lung benefits liability based upon the actuarially computed present and future claims. The cost or reduction of cost due to change in the estimate of black lung benefits charged (credited) to operations for the year ended December 31, 2000, the period from the Partnership's commencement of operations on August 20, 1999 to December 31, 1999, and the Predecessor period from January 1, 1999 to August 19, 1999, was \$123,000, \$(1,028,000), and \$726,000, respectively.

The U.S. Department of Labor has issued revised regulations that will alter the claims process for the federal black lung benefit recipients. Both the coal and insurance industries are currently challenging through litigation certain provisions of the revised regulations. The revised regulations are expected to result in an increase in the incidence and recovery of black lung claims.

#### 14. RELATED PARTY TRANSACTIONS

The Partnership Agreement provides that the Managing GP and its affiliates be reimbursed for all direct and indirect expenses it incurs or payments it makes on behalf of the Partnership, including management's salaries and related benefits, and accounting, budget, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers' compensation management, legal and information technology services. The Managing GP may determine in its sole discretion the expenses that are allocable to the Partnership. Total costs billed by the Managing GP and its affiliates to the Partnership were approximately \$6,503,000, \$3,899,000 and \$1,283,000 for the years ended December 31, 2001 and 2000, and the period from the Partnership's commencement of operations on August 20, 1999 to December 31, 1999, respectively.

ARH allocated certain direct and indirect general and administrative expenses to the Predecessor. These allocations were primarily based on the relative size of the direct mining operating costs incurred by each of the mine locations of the Predecessor. The allocations of general and administrative expenses to the Predecessor were approximately \$2,982,000 for the period from January 1, 1999 to August 19, 1999. Management is of the opinion that the allocations used were reasonable and appropriate.

During November 1999, the Managing GP was authorized by its Board of Directors to purchase up to 1.0 million Common Units of the Partnership. As of December 31, 2001 and 2000, the Managing GP owned 164,000 Common Units that were purchased in the open market at prevailing market prices.

During September 2000, the Special GP acquired coal reserves and the right to acquire additional coal reserves that are (a) contiguous to the Partnership's Webster County Coal, LLC ("WCC") mining complex ("Providence No. 3 Reserves") and (b) contiguous to the Partnership's Hopkins County Coal, LLC ("HCC") mining complex ("Elk Creek Reserves"). Such coal reserves and the rights to acquire

additional coal reserves were transferred to SGP Land, LLC ("SGP Land"), a newly formed wholly-owned subsidiary of the Special GP.

Concurrent with such coal reserve acquisitions, the Special GP, through affiliates, was negotiating for the purchase of (a) the capital stock of Roberts Bros. Coal Co., Inc., Warrior Coal Mining Company, and Warrior Coal Corporation, and (b) the related coal reserves ("Warrior Reserves") owned by Cardinal Trust, LLC (collectively the "Warrior Group"). The Warrior Group's operating assets are located adjacent to the Providence No. 3 Reserves and these operating assets, excluding the Warrior Reserves, were purchased by a newly formed affiliate of the Special GP, Warrior Coal, LLC ("Warrior Coal") in January, 2001. SGP Land acquired the Warrior Reserves, which are located between the Providence No. 3 Reserves and HCC in January, 2001.

SGP Land entered into a mineral lease and sublease with WCC for a portion of each of the Providence No. 3 Reserves and the Warrior Reserves, and granted an option to HCC to lease and/or sublease the Elk Creek Reserves. Under the terms of the WCC lease and sublease, WCC has an annual minimum royalty obligation of \$2.7 million, payable in advance, from 2000 to 2013 or until \$37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. WCC paid an annual minimum royalty of \$2.7 million in 2001 and 2000. Under the terms of the HCC option to lease and sublease, HCC paid option fees of \$684,000 and \$645,000 in 2001 and 2000, respectively. The anticipated annual minimum royalty obligation is \$684,000 payable in advance, from 2002 to 2009.

During 2000, ARH and the Managing GP were approached with the opportunity to purchase certain mining assets of Warrior Coal, located adjacent to the ARGP Group's western Kentucky operation. Warrior Coal is an underground mining complex that utilizes continuous mining units employing room and pillar mining techniques. Warrior Coal produces approximately 1.5 million tons per year, controls reserves that will provide for a minimum of ten years of mining, and has the possibility of controlling additional reserves in the future.

In accordance with the right of first refusal provision in the Omnibus Agreement between ARH and the Partnership's Managing GP, ARH offered the Managing GP the opportunity to purchase Warrior Coal. At the time, the Managing GP declined the opportunity to purchase Warrior Coal as the Partnership had previously committed to major capital expenditures at two existing operations. As a condition to not exercising its right of first refusal, the Partnership requested that ARH enter into a put and call arrangement for Warrior Coal. After further discussions, ARH and the Partnership, with the approval of the Conflicts Committee of the Managing GP, entered into an Amended and Restated Put and Call Option Agreement ("Put/Call Agreement") in January 2001. Concurrently ARH, through an indirect wholly-owned subsidiary, acquired Warrior Coal in January 2001 for \$10 million.

The Put/Call Agreement preserved an opportunity for the Partnership to acquire Warrior Coal during a specified time period in the future, although at a price significantly greater than the price paid by ARH. Under the terms of the Put/Call Agreement, ARH can require the Partnership to purchase Warrior Coal during the period from January 2 to January 11, 2003. The put option price is approximately \$12.5 million. The Partnership can also require ARH to sell Warrior Coal to the Partnership during the period from April 12, 2003 to December 31, 2006. The call option price ranges between \$13.6 million and \$22.2 million depending on when the call option is exercised.

The option provisions of the Put/Call Agreement are subject to certain conditions, among others, including (a) the non-occurrence of a material adverse change in the business and financial condition of Warrior Coal, (b) the prohibition of any dividends or other distributions to Warrior Coal's shareholders, (c) the maintenance of Warrior Coal's assets in good working condition, (d) the prohibition on the sale of any equity interest in Warrior Coal except for the options contained in the Put/Call Agreement, and

(e) the prohibition on the sale or transfer of Warrior Coal's assets except those made in the ordinary course of its business.

The Put/Call Agreement option prices reflect negotiated sale and purchase amounts that both parties determined would allow each party to satisfy acceptable minimum investment returns in the event either the put or call options are exercised. The Partnership has not made a final determination concerning the potential exercise of its call option and has not been advised by ARH concerning ARH's intention to exercise its put option. The Partnership has developed financial projections for Warrior Coal based on due diligence procedures it customarily performs when considering the acquisition of a coal mine. The assumptions underlying the financial projections made by the Partnership for Warrior Coal include (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, at this time, the Partnership believes that the fair value of Warrior Coal is equal to or greater than the put option exercise price.

The Partnership provides management and administrative services to Warrior Coal and SGP Land under an administrative service agreement. Under this agreement, the Partnership has recognized approximately \$1,019,000 as a reduction of general and administrative expenses during the year ended December 31, 2001. Accounts receivable from Warrior Coal of \$108,000 offsets a portion of the due to affiliates at December 31, 2001.

During 2001, the Partnership entered into an agreement with Warrior Coal to perform certain reclamation procedures for the Partnership. The total estimated cost of the reclamation procedures covered by this agreement is \$475,000 of which approximately \$315,000 remains to be expended in 2002 for the expected completion of the reclamation procedures by Warrior Coal.

During 2001, the Partnership made coal purchases of approximately \$3,135,000 from Warrior Coal. Accounts payable to Warrior Coal of \$1,876,000 is included in the amount due to affiliates at December 31, 2001. During December 2001, the Partnership entered into coal supply agreements with Warrior Coal for the purchase of 1.8 million tons for the year ending December 31, 2002.

The Partnership has a noncancelable operating lease arrangement with the Special GP for the coal preparation plant and ancillary facilities at the Gibson County Coal, LLC mining complex. Based on the terms of the lease, the Partnership will make monthly payments of approximately \$216,000 through January, 2010. Lease expense incurred for the years ended December 31, 2001 and 2000 was \$2,592,000 and \$14,000, respectively.

In 2001, SGP Land, as successor in interest to an unaffiliated third-party, entered into an amended mineral lease with MC Mining, LLC ("MC Mining"). Under the terms of the lease, MC Mining has and will pay an annual minimum royalty obligation of \$300,000 until \$6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of \$705,000 for the year ended December 31, 2001.

During 2001, the Partnership entered into agreements with three banks to provide letters of credit in an aggregate amount of \$25.0 million to maintain surety bonds to secure its obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2001 the Partnership had \$15.0 million in letters of credit outstanding. The Special GP guarantees these letters of credit, and as a result the Partnership has agreed to compensate the Special GP for a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. The Partnership paid approximately \$8,800 in guarantee fees to the Special GP for the year ended December 31, 2001.

## 15. COMMITMENTS AND CONTINGENCIES

*Commitments* – The Partnership leases buildings and equipment under operating lease agreements which provide for the payment of both minimum and contingent rentals. The Partnership also has a noncancelable lease with the Special GP (Note 14). Future minimum lease payments under operating leases are as follows (in thousands):

Year Ending December 31,	<u>Affiliate</u>	<u>Others</u>	<u>Total</u>
2002	\$ 2,595	\$ 702	\$ 3,297
2003	2,595	568	3,163
2004	2,595	578	3,173
2005	2,595	578	3,173
2006	2,595	406	3,001
Thereafter	<u>10,595</u>	<u>496</u>	<u>11,091</u>
	<u>\$23,570</u>	<u>\$3,328</u>	<u>\$26,898</u>

Lease expense under all operating leases was \$4,224,000, \$1,409,000, \$801,000, and \$496,000 for the years ended December 31, 2001 and 2000, the period from the Partnership's commencement of operations on August 20, 1999 to December 31, 1999, and the Predecessor period from January 1, 1999 to August 19, 1999, respectively.

*Contractual Commitments* – In connection with the expansion of an existing mine into adjacent coal reserves and construction of a new mine shaft at another existing mine, the Partnership has remaining contractual commitments of approximately \$15.3 million at December 31, 2001.

*General Litigation* – The Partnership is involved in various lawsuits, claims and regulatory proceedings, including those conducted by the Mine Safety and Health Administration, incidental to its business. The Partnership provides for costs related to litigation and regulatory proceedings, including civil fines issued as part of the outcome of such proceedings, when a loss is probable and the amount is reasonably determinable. The Partnership also recorded an expense of \$2,675,000 consisting of \$675,000 relating to a settlement and \$2,000,000 attributable to contingencies associated with third party claims arising out of its mining operations, which is reflected in "Unusual items" in the accompanying consolidated and combined statements of income for the year ended December 31, 2000. In the opinion of management, the outcome of such matters to the extent not previously provided for or covered under insurance, will not have a material adverse effect on the Partnership's business, financial position or results of operations, although management cannot give any assurance to that effect.

*Other* – During September 2001, the Partnership completed its annual property insurance renewal. Recent insurance carrier losses worldwide have created a tightening market reducing available capacity for underwriting property insurance. As a result, the Partnership, and its affiliates retained a 12.5% participating interest along with its insurance carriers in the commercial property program. The aggregate maximum limit in the commercial property program is \$75,000,000 per occurrence, of which, the Partnership is responsible for a maximum limit of \$9,375,000 per occurrence of the amount covered by property insurance. While the Partnership does not have a significant history of material insurance claims, the ultimate amount of claims incurred, if any, are dependent on future developments. As a result, the Partnership's participation in the commercial property program could have a material adverse effect on the Partnership's financial condition and results of operations.

On March 14, 2002, PSI Energy Inc. ("PSI") notified Gibson County Coal LLC that they intended to withhold approximately \$644,819 (excluding interest thereon, if any) in payments due to Gibson County Coal over a three-month period beginning in March through May 2002. This amount relates to alleged penalties associated with a contract specification addressing the hardness of coal provided to PSI. Gibson County Coal and PSI have had on-going discussions since March 2001 concerning the procedures for and testing of the coal supplied by the Gibson County mining complex and have been unable to-date to resolve their differences. Although Gibson County Coal is pursuing on-going discussions with PSI regarding a potential resolution of certain issues concerning contractual interpretation, the Partnership cannot assure that this matter can be resolved without resort to mediation, arbitration, and/or litigation. Gibson County Coal strongly disagrees with PSI's position.

#### 16. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

The Partnership has significant long-term coal supply agreements, some of which contain price adjustment provisions designed to reflect changes in market conditions, labor and other production costs and, when the coal is sold other than FOB the mine, changes in truck rates. Total revenues to major customers, including transportation revenues (Note 2), which exceed ten percent (seven percent for Customer D in 2001) of total revenues are as follows (in thousands):

	<u>Partnership</u>		<u>From Commencement of Operations (on August 20, 1999) to December 31, 1999</u>	<u>Predecessor</u>
	<u>Year Ended December 31,</u>			<u>For the period from January 1, 1999 to August 19, 1999</u>
	<u>2001</u>	<u>2000</u>		
Customer A	\$ 74,091	\$ 58,498	\$ 16,090	\$ 31,328
Customer B	63,241	67,234	23,104	38,875
Customer C	47,492	61,007	26,993	40,752
Customer D	32,614	38,713	11,926	19,582

Trade accounts receivable from these customers totaled approximately \$14.9 million at December 31, 2001. The Partnership's bad debt experience has historically been insignificant, however the Partnership established an allowance of \$763,000 during 2001, due to the Partnership's total credit exposure to Enron Corp., which filed for bankruptcy protection during December, 2001. Financial conditions of its customers could result in a material change to this estimate in future periods. The coal supply agreements with customers A, B, C and D expire in 2010, 2006, 2001 and 2006, respectively.

## 17. GEOGRAPHIC INFORMATION

Included in the consolidated and combined financial statements are the following revenues and long-lived assets relating to geographic locations (in thousands):

	Partnership		From Commencement of Operations (on August 20, 1999) to December 31, 1999	Predecessor
	Year Ended December 31,			For the period from January 1, 1999 to August 19, 1999
	2001	2000		
Revenues:				
United States	\$ 446,300	\$ 363,469	\$ 134,125	\$ 221,339
Other foreign countries	-	-	-	10,494
	<u>\$ 446,300</u>	<u>\$ 363,469</u>	<u>\$ 134,125</u>	<u>\$ 231,833</u>
Long-lived assets:				
United States	\$ 218,877	\$ 210,996	\$ 203,697	\$ 200,057
Other foreign countries	-	-	-	-
	<u>\$ 218,877</u>	<u>\$ 210,996</u>	<u>\$ 203,697</u>	<u>\$ 200,057</u>

## 18. SUPPLEMENTAL CASH FLOW INFORMATION

The Partnership's and Predecessor's supplemental disclosure of cash flow information and other non-cash investing and financing activities were as follows (in thousands):

	Partnership		From Commencement of Operations (on August 20, 1999) to December 31, 1999	Predecessor
	Year Ended December 31,			For the period from January 1, 1999 to August 19, 1999
	2001	2000		
Cash paid for:				
Interest	\$ 18,070	\$ 19,043	\$ 1,173	\$ -
Income taxes paid through Parent (Note 9)	-	-	-	3,504
Noncash investing and financing activities:				
Debt transferred from Special GP	-	-	230,000	-
Marketable securities transferred from Special GP	-	-	15,486	-

## 19. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of the quarterly operating results for the Partnership is as follows (in thousands, except unit and per unit data):

	Quarter Ended			
	March 31, 2001 (1)	June 30, 2001	September 30, 2001	December 31, 2001
Revenues	\$ 106,752	\$ 110,722	\$ 117,894	\$ 110,932
Operating income	8,456	4,012	11,943	803
Net income (loss)	12,375	(46)	7,816	(3,045)
Basic net income (loss) per limited partner unit	\$ 0.79	\$ (0.01)	\$ 0.50	\$ (0.19)
Basic net income (loss) per limited partner unit before accounting change	\$ 0.28	\$ (0.01)	\$ 0.50	\$ (0.19)
Diluted net income (loss) per limited partner unit	\$ 0.77	\$ (0.01)	\$ 0.49	\$ (0.19)
Diluted net income (loss) per limited partner unit before accounting change	\$ 0.28	\$ (0.01)	\$ 0.49	\$ (0.19)
Weighted average number of units outstanding - basic	15,405,311	15,405,311	15,405,311	15,405,311
Weighted average number of units outstanding - diluted	15,680,594	15,681,411	15,678,013	15,708,968

	Quarter Ended			
	March 31, 2000	June 30, 2000	September 30, 2000 (2)	December 31, 2000
Revenues	\$ 89,420	\$ 86,652	\$ 96,459	\$ 90,938
Operating income	6,191	5,912	15,669	3,096
Net income (loss)	2,366	2,098	11,560	(443)
Basic net income (loss) per limited partner unit	\$ 0.15	\$ 0.13	\$ 0.74	\$ (0.03)
Diluted net income (loss) per limited partner unit	\$ 0.15	\$ 0.13	\$ 0.73	\$ (0.03)
Weighted average number of units outstanding - basic	15,405,311	15,405,311	15,405,311	15,405,311
Weighted average number of units outstanding - diluted	15,550,489	15,550,845	15,552,017	15,553,372

- (1) The Partnership changed its method of estimating black lung benefits liability effective January 1, 2001. The cumulative effect of this change resulted in the reduction of this liability and a corresponding increase in net income of \$7,939,000 for the quarter (Note 3).
- (2) The Partnership recorded income of \$12.2 million, which is net of litigation expenses and costs relating to the impairment of certain transloading facility assets. Additionally, the Partnership recorded an expense of \$2.7 million related to litigation matters settled and contingencies associated with other litigation matters. The net effect of these unusual items for the quarter was \$9.5 million (Note 4).

Operating income in the above table represents income from operations before interest expense.

\* \* \* \* \*

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

None.

PART III

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

As is commonly the case with publicly-traded limited partnerships, we are managed and operated by our managing general partner. The following table shows information for the directors and executive officers of the managing general partner. Executive officers and directors are elected for one-year terms.

<u>Name</u>	<u>Age</u>	<u>Position With our Managing General Partner</u>
Joseph W. Craft III	51	President, Chief Executive Officer and Director
Robert G. Sachse	53	Executive Vice President and Director
Thomas L. Pearson	48	Senior Vice President - Law and Administration, General Counsel and Secretary
Michael L. Greenwood	46	Senior Vice President - Chief Financial Officer and Treasurer
Charles R. Wesley	47	Senior Vice President - Operations
Gary J. Rathburn	51	Senior Vice President - Marketing
John J. MacWilliams	46	Director
Preston R. Miller, Jr.	53	Director
John P. Neafsey	62	Director
John H. Robinson	51	Director
Paul R. Tregurtha	66	Director

Joseph W. Craft III has worked for us since 1980. Prior to the formation of Alliance Resource Holdings, Mr. Craft was a Senior Vice President of MAPCO Inc., serving as General Counsel and Chief Financial Officer, and since 1986 as President of MAPCO Coal Inc. Mr. Craft has held his current positions since August 1996. Prior to working with us, Mr. Craft was an attorney at Falcon Coal Corporation and Diamond Shamrock Coal Corporation. Mr. Craft has held numerous industry leadership positions, including past Chairman of the National Coal Council, a Board and Executive Committee member of the National Mining Association, and a Director of the Center for Energy and Economic Development. Mr. Craft holds a Bachelor of Science degree in Accounting and a Juris Doctor degree from the University of Kentucky. Mr. Craft also is

a graduate of the Senior Executive Program of the Alfred P. Sloan School of Management at Massachusetts Institute of Technology.

Robert G. Sachse joined us as Executive Vice President and Vice Chairman in August 2000. Prior to working with us, Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO Inc. merged with The Williams Companies, Inc. Mr. Sachse held various positions with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree from Trinity University and a Juris Doctor degree from the University of Tulsa.

Thomas L. Pearson has worked for us since 1989. Prior to the formation of Alliance Resource Holdings, Mr. Pearson was Assistant General Counsel of MAPCO Inc. and served as General Counsel and Secretary of MAPCO Coal Inc. from 1989-1996. Mr. Pearson has held his current positions since August 1996. Prior to working with us, Mr. Pearson was General Counsel and Secretary of McLouth Steel Products Corporation, one of the largest integrated steel producers in the United States; and Corporate Counsel of Midland-Ross Corporation, a multi-national company with numerous international joint venture companies and projects. Previously, he was an attorney with the law firm Arter & Hadden in Cleveland, Ohio. Mr. Pearson is or has been active in a number of educational, charitable and business organizations, including the following: Vice Chairman, Legal Affairs Committee, National Mining Association; Member, Dean's Committee, The University of Iowa College of Law; and Contributions Committee, Greater Cleveland United Way. Mr. Pearson holds a Bachelor of Arts degree in History and Communications from DePauw University and a Juris Doctor degree from The University of Iowa.

Michael L. Greenwood has worked for us since 1986. Prior to the formation of Alliance Resource Holdings, Mr. Greenwood served in various financial management capacities, including General Manager - Finance of MAPCO Coal Inc., General Manager of Planning and Financial Analysis, and Manager - Mergers and Acquisitions of MAPCO Inc. Mr. Greenwood has held his current positions since August 1996. Prior to working for us, Mr. Greenwood held financial planning and business development management positions in the energy industry with Davis Investments, The Williams Companies, Inc. and Penn Central Corporation. Mr. Greenwood holds a Bachelor of Science degree in Business Administration from Oklahoma State University and a Master of Business Administration degree from the University of Tulsa. Mr. Greenwood has also completed executive programs at Northwestern University, Southern Methodist University and The Center for Creative Leadership.

Charles R. Wesley has worked for us since 1974. Mr. Wesley joined Webster County Coal Corporation in 1974 as an engineering co-op student and worked through the ranks to become General Superintendent. In 1992 he became Vice President of Operations for Mettiki Coal Corporation. He has held his current position since August 1996. Mr. Wesley has served the industry as past President of the West Kentucky Mining Institute and National Mine Rescue Association Post 11. He also served on the board of the Kentucky Mining Institute. Mr. Wesley holds a Bachelor of Science degree in Mining Engineering from the University of Kentucky.

Gary J. Rathburn has worked for us since 1980 when he joined MAPCO Coal Inc. as Manager of Brokerage Coals. Since 1980, Mr. Rathburn has managed all phases of the marketing group involving transportation and distribution, international sales and the brokering of coal. He has held his current position since August 1996. Prior to working for us, Mr. Rathburn was employed by Eastern Associated Coal Corporation in its International Sales and Brokerage groups. Mr. Rathburn has been active in industry groups such as the Maryland Coal Association, The North Carolina Coal Institute and the National Mining Association. Mr. Rathburn was a Director of The National Coal Association and Chairman of the Coal Exporters Association for several years. Mr. Rathburn holds a Bachelor of Arts degree in Political Science

from the University of Pittsburgh and has participated in industry-related programs at the World Trade Institute, Princeton University and the Colorado School of Mines.

John J. MacWilliams has served as a Director since June 1996. Mr. MacWilliams has been a General Partner of J.P. Morgan Partners, LLC since June of 2000. Previously he was a General Partner of the Beacon Group, LP (The Beacon Group) from May 1993 through May 2000. Prior to the formation of The Beacon Group, Mr. MacWilliams was an Executive Director of Goldman Sachs International in London, where he was responsible for heading the firm's International Structured Financing Group. Prior to moving to London, Mr. MacWilliams was a Vice President in the Investment Banking Division of Goldman, Sachs & Co. in New York. Prior to joining Goldman Sachs, Mr. MacWilliams was an attorney at Davis Polk & Wardwell in New York, where he worked on international bank financings, partnership financings, and mergers and acquisitions. Mr. MacWilliams is also a director of Campagne Generale de Geophysique. Mr. MacWilliams holds a Bachelor of Arts degree from Stanford University, Master of Science degree from Massachusetts Institute of Technology, and a Juris Doctor degree from Harvard Law School.

Preston R. Miller, Jr. has served as a Director since June 1996. Mr. Miller has been a General Partner of J.P. Morgan Partners, LLC since June of 2000. Previously he was a General Partner of the Beacon Group from June 1993 through May 2000. Prior to the formation of The Beacon Group, Mr. Miller was employed for fourteen years by Goldman, Sachs & Co. in New York City, where he was a Vice President in the Structured Finance Group and had global responsibility for the coverage of the independent power industry, asset-backed power generation, and oil and gas financings. Mr. Miller also has a background in credit analysis, and was head of the revenue bond rating group at Standard & Poor's Corp. prior to joining Goldman Sachs. Mr. Miller holds a Bachelor of Arts degree from Yale University and a Master of Public Administration degree from Harvard University.

John P. Neafsey has served as Chairman since June 1996. Mr. Neafsey has served as President of JN Associates, an investment consulting firm, since January 1994. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and Director since its founding in 1983. In addition, Mr. Neafsey held numerous other positions during his twenty-three years at The Sun Company, including: Executive Vice President responsible for Canadian operations, Sun Coal Company and Helios Capital Corporation; Chief Financial Officer; and other executive management positions with numerous subsidiary companies. Mr. Neafsey is or has been active in a number of educational, charitable and business organizations, including the following: Director, The West Pharmaceutical Services Company, Longhorn Partners Pipeline Inc. and the Provident Mutual Life Insurance Company; Trustee Emeritus and Presidential Counselor, Cornell University; and Overseer of Cornell-Weill Medical Center. Mr. Neafsey holds Bachelor and Master of Science degrees in Engineering and a Master of Business Administration degree from Cornell University.

John H. Robinson has served as a Director since December 1999. In April 2000, Mr. Robinson joined Amey, plc, a British support services business, as Executive Director of its newly-formed Technology Services Division. Mr. Robinson previously served as Vice Chairman of Black & Veatch, a global engineer-constructor firm, from January 1997 through March 2000. He was also the Chairman of Black & Veatch UK Ltd. and was responsible for guiding strategic development of the firm, having begun his career there in 1973. He is a Director of Coeur Precious Metals Mining Corporation. Mr. Robinson holds Bachelor and Master of Science degrees in Engineering from the University of Kansas and has completed the Owner/President Management Program at the Harvard School of Business.

Paul R. Tregurtha has served as a Director since December 1999. Mr. Tregurtha serves as Chairman and Chief Executive Officer of Mormac Marine Group, Inc. and Chairman of Moran Transportation Company. He is a director and principal officer of several companies involved in water transportation and natural resources, including The Interlake Steamship Company and Lakes Shipping Company. Mr. Tregurtha is also

a director of FleetBoston Financial and FPL Group, Inc., the parent of Florida Power & Light Company. Mr. Tregurtha holds a Bachelor of Science degree in Mechanical Engineering from Cornell University, where he serves as Trustee Emeritus, and a Master of Business Administration degree from the Harvard School of Business.

#### Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities and Exchange Act of 1934, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of the forms furnished to it, or written representations from certain reporting persons, we believe that during 2001 none of our officers and directors was delinquent with respect to any of the filing requirements under Rule 16(a).

#### Reimbursement of Expenses of the Managing General Partner and its Affiliates

The managing general partner does not receive any management fee or other compensation in connection with its management of us. However, our managing general partner and its affiliates, including Alliance Resource Holdings, perform services for us and are reimbursed by us for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits properly allocable to us, as well as all other expenses necessary or appropriate to the conduct of our business, and properly allocable to us. Our partnership agreement provides that the managing general partner will determine the expenses that are allocable to us in any reasonable manner determined by the managing general partner in its sole discretion.

### ITEM 11. EXECUTIVE COMPENSATION

#### Executive Compensation

The following table sets forth certain compensation information for all executive officers of our managing general partner who received salary and bonus compensation in excess of \$100,000 in 2001 and 2000. We were formed in May 1999 but did not commence business until August 1999. Therefore 1999 compensation information is for the period from commencement of our operations (on August 20, 1999) to December 31, 1999.

## Summary Compensation Table

Name and Principal Position	Year	Annual Compensation			Long Term	All Other
		Salary	Bonus (1)	Other Annual Compensation (2)	Compensation Restricted Stock Awards (3)	
Joseph W. Craft III, President, Chief Executive Officer and Director	2001	\$314,700	\$130,000	\$5,250	\$781,875	\$50,562
	2000	292,950	94,200	-	678,150	63,695
	1999	106,313	70,040	700	-	21,495
Thomas L. Pearson, Senior Vice President-Law and Administration, General Counsel and Secretary	2001	192,000	63,000	1,167	140,738	31,914
	2000	177,000	45,000	1,550	122,067	43,856
	1999	64,234	28,306	-	-	12,385
Michael L. Greenwood, Senior Vice President-Chief Financial Officer and Treasurer	2001	162,650	50,000	-	140,738	24,531
	2000	151,400	45,000	-	122,067	26,009
	1999	54,944	28,306	-	-	7,972
Charles R. Wesley, Senior Vice President-Operations	2001	202,000	65,000	925	156,375	33,286
	2000	187,000	47,600	1,500	135,630	32,802
	1999	67,863	35,565	-	-	12,383
Gary J. Rathburn, Senior Vice President-Marketing	2001	167,000	70,000	3,000	140,738	26,702
	2000	152,000	45,000	1,500	122,067	28,008
	1999	55,161	28,306	-	-	9,407

(1) Amounts awarded under the Short-Term Incentive Plan. See "Short-Term Incentive Plan" below.

(2) Amounts reimbursed for income tax preparation and financial planning services.

(3) Awards under the Long-Term Incentive Plan. The amount represents the value of restricted units at the date of issuance. The total number of restricted units and their aggregate market value as of December 31, 2001, were: Mr. Craft, 95,000 units valued at \$2,574,500; Mr. Pearson, 17,100 units valued at \$463,410; Mr. Greenwood, 17,100 units valued at \$463,410; Mr. Wesley, 19,000 units valued at \$514,900; Mr. Rathburn, 17,100 units valued at \$463,410. Units granted under the Long-Term Incentive Plan do not vest until the end of the subordination period, which will generally not end before September 30, 2004. See "Long-Term Incentive Plan" below.

(4) Amounts represent (a) the managing general partner's matching contributions to its 401(k) Plan and (b) the managing general partner's contribution to its Supplemental Executive Retirement Plan.

### Compensation Of Directors

Under the managing general partner's Directors Compensation Program (Directors Plan) each non-employee Director is paid an annual retainer of \$21,500. The annual retainer is payable in common units to be paid on a quarterly basis in advance determined by dividing the pro rata annual retainer payable on such date by the closing sales price per common unit averaged over the immediately preceding ten trading days. Each non-employee director may elect to defer all or a portion of his or her compensation under the Deferred Compensation Plan for Directors.

In addition, each non-employee director participates in the Long-Term Incentive Plan. The directors restricted units vest in accordance with the procedure described below. Messrs. MacWilliams and Miller have declined compensation under the Directors and Long-Term Incentive Plans.

Mr. Sachse has a consulting agreement with the managing general partner for a term of three years, effective August 14, 2000. The consulting agreement provides that Mr. Sachse will serve as Executive Vice President of the managing general partner and devote his services on a part-time basis. In addition to compensation received under the Directors Plan and Long-Term Incentive Plan described above, Mr. Sachse is entitled to receive an annual fee of \$150,000 payable in arrears monthly. Mr. Sachse also is entitled to receive quarterly payments in arrears of \$7,500 less the market value of 250 common units calculated by the closing sales price per common unit averaged over the immediately preceding ten trading days. A copy of the consulting agreement with Mr. Sachse is an exhibit hereto.

#### Employment Agreements

The executive officers of the managing general partner and some additional members of senior management will enter into employment agreements among the executive officer or member of senior management, on the one hand, and the managing general partner on the other. We reimburse the managing general partner for the compensation and benefits costs under these agreements. This summary of the terms of the employment agreements does not purport to be complete, but outlines their material provisions. A form of the agreements with each of Messrs. Craft, Pearson, Greenwood, Wesley and Rathburn is an exhibit hereto.

Each of the employment agreements had an initial term that expired on December 31, 2001, but automatically extend for successive one-year terms unless either party gives 12 months prior notice to the other party. The employment agreements provide for a base salary, subject to review annually, of \$321,950, \$192,000, \$166,400, \$207,000 and \$167,000 for Messrs. Craft, Pearson, Greenwood, Wesley and Rathburn, respectively. The employment agreements provide for continued salary payments, bonus and benefits for a period of three years, in the case of Mr. Craft, and 18 months, in the case of Messrs. Pearson, Greenwood, Wesley and Rathburn, following termination of employment, except in the case of a change of control of the managing general partner.

In the case of a "change of control" as defined in the agreements, in lieu of the continuation of salary and benefits, that executive will be entitled to a lump sum payment in an amount equal to three times base salary plus bonus, in the case of Mr. Craft, and two times base salary plus bonus in the case of Messrs. Pearson, Greenwood, Wesley and Rathburn. Unless the executive waives his or her right to the continuation of base salary and bonus, the agreements provide for a noncompetition period of 18 months. The noncompetition period does not apply after a change in control. Amounts paid by the managing general partner pursuant to the employment agreements will be reimbursed by us.

The executives who are subject to employment agreements also participate in the Short- and Long-Term Incentive Plans of the managing general partner described below along with other members of management. They also are entitled to participate in the other employee benefit plans and programs that the managing general partner provides for its employees.

#### Long-Term Incentive Plan

Effective January 1, 2000, the managing general partner adopted the Long-Term Incentive Plan (LTIP) for certain employees and directors of the managing general partner and its affiliates who perform services for us. The summary of the LTIP contained herein does not purport to be complete, but outlines its material provisions.

The LTIP is administered by the compensation committee of the managing general partner's Board of Directors. Annual grant levels for designated participants are recommended by the President and CEO of the managing general partner, subject to the review and approval of the compensation committee. We will reimburse the managing general partner for all costs incurred pursuant to the programs described below.

Grants are made either of restricted units, which are "phantom" units that entitle the grantee to receive a common unit or an equivalent amount of cash upon the vesting of a phantom unit, or options to purchase common units. Common units to be delivered upon the vesting of restricted units or to be issued upon exercise of a unit option will be acquired by the managing general partner in the open market at a price equal to the then prevailing price, or directly from Alliance Resource Holdings or any other third party, including units newly issued by us, or use units already owned by the managing general partner, or any combination of the foregoing. The managing general partner is entitled to reimbursement by us for the cost incurred in acquiring these common units or in paying cash in lieu of common units upon vesting of the restricted units. If we issue new common units upon payment of the restricted units or unit options instead of purchasing them, the total number of common units outstanding will increase. The aggregate number of units reserved for issuance under the LTIP is 600,000. Effective January 1, 2000 and 2001, the compensation committee approved initial grants of 142,100 and 129,200 restricted units, vesting at the end of the subordination period, which generally will not end before September 30, 2004. During 2001, 8,500 units were forfeited. Effective as of January 1, 2002, the compensation committee approved additional grants of 131,885 restricted units, which vest at the end of the subordination period.

*Restricted Units.* Restricted units will vest over a period of time as determined by the compensation committee. However, if a grantee's employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will be automatically forfeited, unless the compensation committee, in its sole discretion, provides otherwise. In addition, vested restricted units will not be payable before the end of the subordination period, which will generally not end before September 30, 2004.

The issuance of the common units pursuant to the restricted unit plan is intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation in respect of the common units. Therefore, no consideration will be payable by the plan participants upon receipt of the common units, and we receive no remuneration for these units. Following the subordination period, the compensation committee, in its discretion, may grant distribution equivalent rights with respect to restricted units.

*Unit Options.* We have not made any grants of unit options. The compensation committee may, in the future, determine to make unit option grants to employees and directors containing the specific terms that they determine. When granted, unit options will have an exercise price set by the compensation committee which may be above, below or equal to the fair market value of a common unit on the date of grant. Unit options, if any, granted during the subordination period will become exercisable upon, and in the same proportions as, the conversion of the subordinated units to common units, or at a later date as determined by the compensation committee in its sole discretion.

The managing general partner's Board of Directors, in its discretion, may terminate the LTIP at any time with respect to any common units for which a grant has not previously been made. The managing general partner's Board of Directors will also have the right to alter or amend the LTIP or any part of it from time to time, subject to unitholder approval as required by the exchange upon which the common units may be listed at that time; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the affected participant. In addition, the managing general partner may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward its employees. The managing general partner is reimbursed for all compensation expenses incurred on our behalf.

#### Short-Term Incentive Plan

Effective January 1, 1999, the managing general partner adopted a Short-Term Incentive Plan (STIP) for management and other salaried employees. The STIP is designed to enhance the financial performance by

rewarding management and our salaried employees and those of the managing general partner with cash awards for our achieving an annual financial performance objective. The annual performance objective for each year is recommended by the President and CEO of the managing general partner and approved by the compensation committee of its Board of Directors prior to January 1 of that year. The STIP is administered by the compensation committee. Individual participants and payments each year are determined by and in the discretion of the compensation committee, and the managing general partner is able to amend the plan at any time. The managing general partner is entitled to reimbursement by us for the costs incurred under the STIP.

#### Supplemental Executive Retirement Plan

Effective January 1, 1997, the managing general partner adopted a supplemental executive retirement plan (SERP) for certain officers and key employees. The purpose of the SERP is to enhance our ability to retain specific officers and key employees, by providing them with the deferred compensation benefits contained in the SERP. The intent of the SERP is to provide each participant with retirement benefits that are comparable in value to those of similar retirement programs administered by other companies, as well as to align each participant's supplemental benefits under the SERP with the interests of our unitholders. All allocations made to participants under the SERP are made in the form of phantom units. The SERP is administered by the compensation committee. The managing general partner is able to amend or terminate the plan at any time. The managing general partner is entitled to reimbursement by us for its costs incurred under the SERP.

#### ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information as of March 1, 2002, regarding the beneficial ownership of common and subordinated units held by (a) each person known by the managing general partner to be the beneficial owner of 5% or more of the common and subordinated units, (b) each director and executive officer of the managing general partner and (c) all directors and executive officers of the managing general partner as a group. The managing general partner is owned by funds affiliated with The Beacon Group and members of management. The special general partner is a wholly-owned subsidiary of Alliance Resource Holdings. The address of Alliance Resource Holdings, the managing general partner and the special general partner is 1717 South Boulder Avenue, Tulsa, Oklahoma 74119.

<u>Name of Beneficial Owner</u>	<u>Common Units Beneficially Owned (8)</u>	<u>Percentage of Common Units Beneficially Owned</u>	<u>Subordinated Units Beneficially Owned</u>	<u>Percentage of Subordinated Units Beneficially Owned</u>	<u>Percentage of Total Units Beneficially Owned</u>
Alliance Resource GP, LLC (2)	1,232,780	13.72%	6,422,531	100%	49.7%
Alliance Resource Management GP, LLC (3)	164,000	1.83%	-	-	1.1%
Joseph W. Craft III (1) (7)	85,468	*	-	-	*
Robert G. Sachse (1)	2,998	*	-	-	*
Thomas L. Pearson (1)	15,897	*	-	-	*
Michael L. Greenwood (1)	33,204	*	-	-	*
Charles R. Wesley (1)	25,479	*	-	-	*
Gary J. Rathburn (1)	13,721	*	-	-	*
John J. MacWilliams (4)	1,396,780	15.55%	6,422,531	100%	50.8%
Preston R. Miller, Jr. (4)	1,396,780	15.55%	6,422,531	100%	50.8%
John P. Neafsey (1)	13,204	*	-	-	*
John H. Robinson (5)	3,421	*	-	-	*
Paul R. Tregurtha (6)	3,421	*	-	-	*
All directors and executive officers as a group (11 persons)	1,593,593	17.74%	6,422,531	100%	52.0%

\* Less than one percent.

- (1) The address of Messrs. Craft, Sachse, Pearson, Greenwood, Wesley, Rathburn and Neafsey is 1717 South Boulder Avenue, Tulsa, Oklahoma 74119.
- (2) Alliance Resource Holdings may be deemed to beneficially own the common units and the subordinated units held by the special general partner, as a result of Alliance Resource Holdings' ownership of all of the membership interests in the special general partner. MPC Partners, LP (MPC Partners), an affiliate of the Beacon Group, may also be deemed to beneficially own the common units and the subordinated units held by the special general partner as a result of MPC Partners' ownership of 86.2% of Alliance Resource Holding's outstanding common stock.
- (3) The managing general partner is an affiliate of the special general partner, and as a consequence the special general partner may be deemed to beneficially own the common units held by the managing general partner.
- (4) Messrs. MacWilliams and Miller may also be deemed to share beneficial ownership of the common units and the subordinated units held by the special general partner and the managing general partner by virtue of their status as partners of The Beacon Group, an affiliate of MPC Partners. Messrs. MacWilliams and Miller disclaim beneficial ownership of the common and subordinated units held by the special general partner and the managing general partner. The address of Messrs. MacWilliams and Miller is Beacon Group Energy Funds, 222 Berkeley St., 17<sup>th</sup> floor, Boston, Massachusetts 10020.
- (5) The address of Mr. Robinson is 24 Hanover Square, London, England W1S1JD.
- (6) The address of Mr. Tregurtha is 3 Landmark Square, Stamford, Connecticut 06901.
- (7) Mr. Craft may also be deemed to share beneficial ownership of an additional 13,500 common units held by a private foundation for which he serves as a trustee. Mr. Craft disclaims beneficial ownership of the common units held by the private foundation.
- (8) The amounts set forth do not include any restricted units granted under the LTIP.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

### Certain Relationships and Related Transactions

The special general partner owns 1,232,780 common units and 6,422,531 subordinated units representing an aggregate 48.7% limited partner interest in us. In addition, the general partners own, on a combined basis, an aggregate 2% general partner interest in us, the intermediate partnership and the subsidiaries. The managing general partner's ability, as managing general partner, to manage and operate us and its ownership of 164,000 common units together with the special general partner's ownership of 1,232,780 common units and 6,422,531 subordinated units, effectively gives the general partners the ability to veto some of our actions and to control our management.

### Unit Purchase Program by the Managing General Partner

The managing general partner authorized a common unit purchase program in November 1999 for the purchase of up to the greater of one million common units or \$15 million of common units. As of December 31, 2001, the managing general partner has purchased 164,000 common units. The common units purchased by the managing general partner retain their rights to receive quarterly distributions of available cash.

### Transactions Between the Partnership, Special General Partner and Alliance Resource Holdings

During September 2000, the special general partner acquired coal reserves and the right to acquire additional coal reserves (a) contiguous to our Dotiki mine (Providence No. 3 Reserves) and (b) contiguous to Hopkins County Coal (Elk Creek Reserves). Such coal reserves and the rights to acquire additional coal

reserves were transferred to SGP Land, LLC (SGP Land), a newly formed wholly-owned subsidiary of the special general partner.

Concurrent with such coal reserve acquisitions, the special general partner, through affiliates, was negotiating for the purchase of (a) the capital stock of Roberts Bros. Coal Co., Inc., Warrior Coal Mining Company, and Warrior Coal Corporation, and (b) the related coal reserves (Warrior Reserves) owned by Cardinal Trust, LLC (collectively, the Warrior Group). The Warrior Group's operating assets are located adjacent to the Providence No. 3 Reserves and these operating assets, excluding the Warrior Reserves, were purchased by a newly formed affiliate of the special general partner, Warrior Coal, LLC (Warrior Coal) in January 2001. SGP Land acquired the Warrior Reserves, which are located between the Providence No. 3 Reserves and Hopkins County Coal.

SGP Land entered into a mineral lease and sublease with Webster County Coal for a portion of each of the Providence No. 3 Reserves and the Warrior Reserves, and granted an option to Hopkins County Coal to lease and/or sublease the Elk Creek Reserves. Under the terms of the Webster County Coal lease and sublease, Webster County Coal has an annual minimum royalty obligation of \$2.7 million, payable in advance, from 2000 to 2013, or until \$37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid an annual minimum royalty of \$2.7 million in 2001 and 2000. Under the terms of the Hopkins County Coal option to lease and sub-lease, Hopkins County Coal paid option fees of \$684,000 and \$645,000 during 2001 and 2000, respectively. The anticipated annual minimum royalty obligation is \$684,000 payable in advance, from 2002 to 2009.

During 2000, Alliance Resource Holdings and our managing general partner were approached with the opportunity to purchase certain mining assets of Warrior Coal located adjacent to our western Kentucky operations. Warrior Coal is an underground mining complex that utilizes continuous mining units employing room and pillar mining techniques. Warrior Coal produces approximately 1.5 million tons per year, controls reserves that will provide for a minimum of ten years of mining, and has the possibility of controlling additional reserves in the future.

In accordance with the right of first refusal provision in the omnibus agreement between Alliance Resource Holdings and our managing general partner, Alliance Resource Holdings offered the managing general partner the opportunity to purchase Warrior Coal. At the time, the managing general partner declined the opportunity to purchase Warrior Coal as we had previously committed to major capital expenditures at two existing operations. As a condition to not exercising our right of first refusal, our managing general partner requested that Alliance Resource Holdings enter into a put and call arrangement for Warrior Coal. After further discussions, we and Alliance Resource Holdings, with the approval of the conflicts committee of our managing general partner, entered into an Amended and Restated Put and Call Option Agreement ("Put/Call Agreement") in January 2001. Concurrently, Alliance Resource Holdings, through an indirect wholly-owned subsidiary, acquired Warrior Coal in January 2001 for \$10 million.

The Put/Call Agreement preserved an opportunity for us to acquire Warrior Coal during a specified time period in the future, although at a price significantly greater than the price paid by Alliance Resource Holdings. Under the terms of the Put/Call Agreement, Alliance Resource Holdings can require us to purchase Warrior Coal during the period from January 2 to January 11, 2003. The put option price is approximately \$12.5 million. We can also require Alliance Resource Holdings to sell Warrior Coal to us during the period from April 12, 2003 to December 31, 2006. The call option price ranges between \$13.6 million and \$22.2 million depending on when the call option is exercised.

The option provisions of the Put/Call Agreement are subject to certain conditions, among others, including (a) the non-occurrence of a material adverse change in the business and financial condition of Warrior Coal, (b) the prohibition of any dividends or other distributions to Warrior Coal's shareholders, (c) the maintenance

of Warrior Coal's assets in good working condition, (d) the prohibition on the sale of any equity interest in Warrior Coal except for the options contained in the Put/Call Agreement, and (e) the prohibition on the sale or transfer of Warrior Coal's assets except those made in the ordinary course of its business.

The Put/Call Agreement option prices reflect negotiated sale and purchase amounts that both parties determined would allow each party to satisfy acceptable minimum investment returns in the event either the put or call options are exercised. We have not made a final determination concerning the potential exercise of our call option and have not been advised by Alliance Resource Holdings concerning Alliance Resource Holdings' intention to exercise its put option. We have developed financial projections for Warrior Coal based on due diligence procedures we customarily perform when considering the acquisition of a coal mine. The assumptions underlying the financial projections made by us for Warrior Coal include (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, at this time, we believe that the fair value of Warrior Coal is equal to or greater than the put option exercise price.

We provide management and administrative services to Warrior Coal and SGP Land under an administrative service agreement. Under this agreement, we recognized approximately \$1.0 million as a reduction to our general and administrative expenses. Accounts receivable from Warrior Coal of \$108,000 offsets a portion of the due to affiliates at December 31, 2001. This transaction was reviewed and approved by the conflicts committee.

During 2001, we entered into an agreement with Warrior Coal to perform certain reclamation procedures for us. The total estimated cost of the reclamation procedures covered by this agreement is \$475,000 of which approximately \$315,000 remains to be expended in 2002 for the expected completion of the reclamation procedures by Warrior Coal.

During 2001, we made coal purchases of approximately \$3.1 million from Warrior Coal. Accounts payable to Warrior Coal were \$1.9 million and are included in the amount due to affiliates in our consolidated balance sheet as of December 31, 2001. During December 2001, we entered into coal supply agreements with Warrior Coal for the purchase of up to 1.8 million tons for the year ending December 31, 2002. This transaction was reviewed and approved by the Conflicts Committee.

We have a noncancelable operating lease arrangement with the special general partner for a coal preparation plant and ancillary facilities at Gibson County Coal. This transaction was reviewed and approved by the Conflicts Committee. Under the terms of the lease, we began making monthly payments commencing January 1, 2001, of approximately \$216,000, which will continue through January 2010.

During 2001, SGP Land, as successor-in-interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining, LLC (MC Mining). Under the terms of the lease, MC Mining pays an annual minimum royalty obligation of \$300,000 until \$6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. This transaction was reviewed and approved by the Conflicts Committee. MC Mining paid royalties of \$705,000 for the year ended December 31, 2001.

During 2001, we entered into agreements with three banks to provide letters of credit in an aggregate amount of \$25.0 million to maintain surety bonds to secure its obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2001 we had \$15.0 million in letters of credit outstanding. The special general partner guarantees these letters of credit, and as a result we have agreed to compensate the Special GP for a fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. We paid approximately \$8,800 in guarantee fees to the Special GP for the year ended December 31, 2001. This transaction was reviewed and approved by the Conflicts Committee.

We may enter into similar arrangements in the future to support the acquisition of additional reserve properties or to develop facilities at our existing mining complexes.

#### Other Related Party Transactions

J.P. Morgan Chase & Co. (Chase) is paying agent, co-administrative agent and a lender under our Credit Facility. In 2001, we made interest and principal payments and principle to Chase on outstanding borrowings and paid Chase customary fees for their other services. We expect that these relationships will continue in 2002. The Beacon Group is an affiliate of Chase. Messrs. MacWilliams and Miller are General Partners of the Beacon Group and Directors of the managing general partner.

FleetBoston is a lender under our Credit Facility. In 2001, we made interest and principal payments to FleetBoston on outstanding borrowings. We expect this relationship to continue in 2002. Mr. Tregurtha, director of the managing general partner, also serves as a director for FleetBoston.

#### Omnibus Agreement

Concurrent with the closing of our initial public offering, we entered into an omnibus agreement with Alliance Resource Holdings and the general partners, which governs potential competition among us and the other parties to this agreement. Alliance Resource Holdings agreed, and caused its controlled affiliates to agree, for so long as management and funds managed by The Beacon Group and its affiliates control the managing general partner, not to engage in the business of mining, marketing or transporting coal in the U.S. unless it first offers us the opportunity to engage in a potential activity or acquire a potential business, and the Board of Directors of the managing general partner, with the concurrence of its conflicts committee, elects to cause us not to pursue such opportunity or acquisition. In addition, Alliance Resource Holdings has the ability to purchase businesses, the majority value of which is not mining, marketing or transporting coal, provided Alliance Resource Holdings offers us the opportunity to purchase the coal assets following their acquisition. The restriction does not apply to the assets retained and business conducted by Alliance Resource Holdings at the closing of our initial public offering. Except as provided above, Alliance Resource Holdings and its controlled affiliates are prohibited from engaging in activities in which they compete directly with us. In addition, The Beacon Group, and the funds it manages, are prohibited from owning or engaging in businesses which compete with us. In addition to its non-competition provisions, this agreement contains provisions which indemnify us against liabilities associated with certain assets and businesses of Alliance Resource Holdings which were disposed of or liquidated prior to consummating our initial public offering.

## PART IV

### ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) (1) Financial Statements.

The response to this portion of Item 14 is submitted as a separate section herein under Part II, Item 8. - Financial Statements and Supplementary Data.

(a)(2) Financial Statement Schedules.

Schedule II – Valuation and Qualifying Accounts – Year ended December 31, 2001, is set forth under Part II Item 8. - Financial Statements and Supplementary Data. All other schedules are omitted because they are not applicable or the information is shown in the financial statements or notes thereto.

(a)(3) Index of Exhibits.

- 3.1 Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 3.1 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 3.2 Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P. (Incorporated by reference to Exhibit 3.2 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 3.3 Certificate of Limited Partnership of Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 3.6 of the Registrant's Registration Statement on Form S-1 filed with the Commission on May 20, 1999 (Reg. No. 333-78845)).
- 3.4 Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P. (Incorporated by reference to Exhibit 3.8 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 3.5 Certificate of Formation of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.7 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 23, 1999 (Reg. No. 333-78845)).
- 3.6 Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.4 of the Registrant's Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).
- 3.7 Amendment No. 1 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.5 of the Registrant's Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).

- 3.8 Amendment No. 2 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.6 of the Registrant's Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).
- 4.1 Form of Common Unit Certificate (Included as Exhibit A to the Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.)
- 10.1 Credit Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC, JP Morgan Chase Bank (formerly The Chase Manhattan Bank) (as paying agent), Deutsche Bank AG, New York Branch (as documentation agent), Citicorp USA, Inc. and JP Morgan Chase Bank (as co-administrative agents) and the lenders named therein. (Incorporated by reference to Exhibit 10.1 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- \*10.2 Amendment No. 1 dated December 7, 2001, to the Credit Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC, JP Morgan Chase Bank (formerly The Chase Manhattan Bank) (as paying agent), Deutsche Bank AG, New York Branch (as documentation agent), Citicorp USA, Inc. and JP Morgan Chase Bank (as co-administrative agents) and the lenders named therein.
- 10.3 Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein. (Incorporated by reference to Exhibit 10.20 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 10.4 Letter of Credit Facility Agreement dated as of June 29, 2001, between Alliance Resource Partners, L.P. and Bank of Oklahoma, National Association. (Incorporated by reference to Exhibit 10.20 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.5 Promissory Note Agreement dated as of July 31, 2001, between Alliance Resource Partners, L.P. and Bank of Oklahoma, N. A. (Incorporated by reference to Exhibit 10.21 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.6 Guarantee Agreement, dated as of July 31, 2001, between Alliance Resource GP, LLC and Bank of Oklahoma, N.A. (Incorporated by reference to Exhibit 10.22 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.7 Letter of Credit Facility Agreement dated as of August 30, 2001, between Alliance Resource Partners, L.P. and Fifth Third Bank. (Incorporated by reference to Exhibit 10.23 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.8 Guarantee Agreement, dated as of August 30, 2001, between Alliance Resource GP, LLC and Firth Third Bank. (Incorporated by reference to Exhibit 10.24 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

- 10.9 Letter of Credit Facility Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association. (Incorporated by reference to Exhibit 10.25 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.10 Promissory Note Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, N.A. (Incorporated by reference to Exhibit 10.26 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.11 Guarantee Agreement, dated as of October 2, 2001, between Alliance Resource GP, LLC and Bank of the Lakes, N.A. (Incorporated by reference to Exhibit 10.27 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.12 Guaranty Fee Agreement dated as of July 31, 2001, between Alliance Resource Partners, L.P. and Alliance Resource GP, LLC. (Incorporated by reference to Exhibit 10.28 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.13 Contribution and Assumption Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. and the other parties named therein. (Incorporated by reference to Exhibit 10.3 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 10.14 Omnibus Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.4 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 10.15 Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan (as amended). (Incorporated by reference to Exhibit 10.11 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 10.16 Alliance Resource Management GP, LLC Short-Term Incentive Plan. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 10.17 Alliance Resource Management GP, LLC Supplemental Executive Retirement Plan. (Incorporated by reference to Exhibit 99.2 of the Registrant's Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)).
- 10.18 Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors. (Incorporated by reference to Exhibit 99.3 of the Registrant's Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)).
- 10.19 Restated and Amended Coal Supply Agreement, dated February 1, 1986, among Seminole Electric Cooperative, Inc., Webster County Coal Corporation and White

County Coal Corporation. (Incorporated by reference to Exhibit 10.9 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).

- 10.20 Amendment No. 1 to the Restated and Amended Coal Supply Agreement effective April 1, 1996, between MAPCO Coal Inc., Webster County Coal Corporation, White County Coal Corporation, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.14 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File No. 000-26823).
- 10.21 Interim Coal Supply Agreement effective May 1, 2000, between Alliance Coal, LLC and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.15 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File No. 000-26823).
- 10.22 Contract for Purchase and Sale of Coal, dated January 31, 1995, between Tennessee Valley Authority and Webster County Coal Corporation. (Incorporated by reference to Exhibit 10.10 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 10.23 Assignment/Transfer Agreement between Andalex Resources, Inc., Hopkins County Coal LLC, Webster County Coal Corporation and Tennessee Valley Authority, dated January 23, 1998, with Exhibit A – Contract for Purchase and Sale of Coal between Tennessee Valley Authority and Andalex Resources, Inc., dated January 31, 1995. (Incorporated by reference to Exhibit 10.11 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 10.24 Contract for Purchase and Sale of Coal, dated July 7, 1998, between Tennessee Valley Authority and Webster County Coal Corporation. (Incorporated by reference to Exhibit 10.12 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 10.25 Contract for Purchase and Sale of Coal, dated July 7, 1998, between Tennessee Valley Authority and White County Coal Corporation. (Incorporated by reference to Exhibit 10.13 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 10.26 Agreement for Supply of Coal to the Mt. Storm Power Station, dated January 15, 1996, between Virginia Electric and Power Company and Mettiki Coal Corporation. (Incorporated by reference to Exhibit 10. (t) to MAPCO Inc.'s Annual Report on Form 10-K, filed April 1, 1996, File No. 1-5254).
- \*10.27 Coal Feedstock Supply Agreement dated October 26, 2001, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Portions of this agreement have been omitted based on a request for confidential treatment. Those omitted portions have been filed with the SEC).
- \*10.28 Amendment No. 1 to Coal Feedstock Supply Agreement dated February 28, 2002, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Portions

of this agreement have been omitted based on a request for confidential treatment. Those omitted portions have been filed with the SEC).

- 10.29 Amended and Restated Put and Call Option Agreement dated February 12, 2001 between ARH Warrior Holdings, Inc. and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.17 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 000-26823).
- 10.30 Consulting Agreement for Mr. Sachse dated January 1, 2001. (Incorporated by reference to Exhibit 10.18 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 000-26823).
- 10.31 Form of Employee Agreement for Messrs. Craft, Pearson, Greenwood, Wesley and Rathburn. (Incorporated by reference to Exhibit 10.6 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on August 9, 1999 (Reg. No. 333-78845)).
- 18.1 Preferability Letter on Accounting Change. (Incorporated by reference to Exhibit 18.1 of the Registrant's Amended Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2001, File No. 000-26823).
- \* 21.1 List of Subsidiaries
- \* 23.1 Consent of Deloitte & Touche LLP regarding Form S-3, Registration No. 333-85282
- \* 23.2 Consent of Deloitte & Touche LLP regarding Form S-8 Registration No. 333-85258

\* Filed here with

(b) Reports on Form 8-K:

None.

## Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, in Tulsa, Oklahoma, on March 29, 2002.

ALLIANCE RESOURCE PARTNERS, L.P.

By: Alliance Resource Management GP, LLC  
its managing general partner

/s/ Michael L. Greenwood

Michael L. Greenwood  
Senior Vice President,  
Chief Financial Officer  
and Treasurer  
(Principal Financial Officer and  
Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Joseph W. Craft III</u> Joseph W. Craft III	President, Chief Executive Officer and Director (Principal Executive Officer)	March 29, 2002
<u>/s/ Michael L. Greenwood</u> Michael L. Greenwood	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer and Principal Accounting Officer)	March 29, 2002
<u>/s/ John J. MacWilliams</u> John J. MacWilliams	Director	March 29, 2002
<u>/s/ Preston R. Miller, Jr.</u> Preston R. Miller, Jr.	Director	March 29, 2002
<u>/s/ John P. Neafsey</u> John P. Neafsey	Director	March 29, 2002
<u>/s/ John H. Robinson</u> John H. Robinson	Director	March 29, 2002
<u>/s/ Robert G. Sachse</u> Robert G. Sachse	Executive Vice President and Director	March 29, 2002
<u>/s/ Paul R. Tregurtha</u> Paul R. Tregurtha	Director	March 29, 2002

## EXHIBIT INDEX

<u>Exhibit Number</u>	<u>Description</u>
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4.1	Form of Common Unit Certificate (Included as Exhibit A to the Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.).
10.1	Credit Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC, JP Morgan Chase Bank (formerly The Chase Manhattan Bank) (as paying agent), Deutsche Bank AG, New York Branch (as documentation agent), Citicorp USA, Inc. and JP Morgan Chase Bank (as co-administrative agents) and the lenders named therein. (Incorporated by reference to Exhibit 10.1 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
*10.2	Amendment No. 1, dated December 7, 2001, to the Credit Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC, JP Morgan Chase Bank

(formerly The Chase Manhattan Bank) (as paying agent), Deutsche Bank AG, New York Branch (as documentation agent), Citicorp USA, Inc. and JP Morgan Chase Bank (as co-administrative agents) and the lenders named therein.

- 10.3 Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein. (Incorporated by reference to Exhibit 10.2 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
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- 10.6 Guarantee Agreement, dated as of July 31, 2001, between Alliance Resource GP, LLC and Bank of Oklahoma, N.A. (Incorporated by reference to Exhibit 10.22 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
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- 10.9 Letter of Credit Facility Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association. (Incorporated by reference to Exhibit 10.25 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
- 10.10 Promissory Note Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, N.A. (Incorporated by reference to Exhibit 10.26 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
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- 10.13 Contribution and Assumption Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. and the other parties named therein. (Incorporated by reference to Exhibit 10.3 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
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- 10.15 Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan (as amended). (Incorporated by reference to Exhibit 10.11 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 10.16 Alliance Resource Management GP, LLC Short-Term Incentive Plan. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
- 10.17 Alliance Resource Management GP, LLC Supplemental Executive Retirement Plan. (Incorporated by reference to Exhibit 99.2 of the Registrant's Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)).
- 10.18 Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors. (Incorporated by reference to Exhibit 99.3 of the Registrant's Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)).
- 10.19 Restated and Amended Coal Supply Agreement, dated February 1, 1986, among Seminole Electric Cooperative, Inc., Webster County Coal Corporation and White County Coal Corporation. (Incorporated by reference to Exhibit 10.9 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 10.20 Amendment No. 1 to the Restated and Amended Coal Supply Agreement effective April 1, 1996 between MAPCO Coal Inc., Webster County Coal Corporation, White County Coal Corporation, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.14 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File No. 000-26823).
- 10.21 Interim Coal Supply Agreement effective May 1, 2000 between Alliance Coal, LLC and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.15 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File No. 000-26823).
- 10.22 Contract for Purchase and Sale of Coal, dated January 31, 1995, between Tennessee Valley Authority and Webster County Coal Corporation. (Incorporated by reference to Exhibit 10.10 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).

- 10.23 Assignment/Transfer Agreement between Andalex Resources, Inc., Hopkins County Coal LLC, Webster County Coal Corporation and Tennessee Valley Authority, dated January 23, 1998, with Exhibit A – Contract for Purchase and Sale of Coal between Tennessee Valley Authority and Andalex Resources, Inc., dated January 31, 1995. (Incorporated by reference to Exhibit 10.11 of the Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 10.24 Contract for Purchase and Sale of Coal, dated July 7, 1998, between Tennessee Valley Authority and Webster County Coal Corporation. (Incorporated by reference to Exhibit 10.12 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 10.25 Contract for Purchase and Sale of Coal, dated July 7, 1998, between Tennessee Valley Authority and White County Coal Corporation. (Incorporated by reference to Exhibit 10.13 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
- 10.26 Agreement for Supply of Coal to the Mt. Storm Power Station, dated January 15, 1996, between Virginia Electric and Power Company and Mettiki Coal Corporation. (Incorporated by reference to Exhibit 10. (t) to MAPCO Inc.'s Annual Report on Form 10-K, filed April 1, 1996, File No. 1-5254).
- \*10.27 Coal Feedstock Supply Agreement dated October 26, 2001, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Portions of this agreement have been omitted based on a request for confidential treatment. Those omitted portions have been filed with the SEC).
- \*10.28 Amendment No. 1 to Coal Feedstock Supply Agreement dated February 28, 2002, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Portions of this agreement have been omitted based on a request for confidential treatment. Those omitted portions have been filed with the SEC).
- 10.29 Amended and Restated Put and Call Option Agreement dated February 12, 2001 between ARH Warrior Holdings, Inc. and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.17 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 000-26823).
- 10.30 Consulting Agreement for Mr. Sachse dated January 1, 2001. (Incorporated by reference to Exhibit 10.18 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 000-26823).
- 10.31 Form of Employment Agreement for Messrs. Craft, Pearson, Greenwood, Wesley and Rathburn. (Incorporated by reference to Exhibit 10.6 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on August 9, 1999 (Reg. No. 333-78845)).
- 18.1 Preferability Letter on Accounting Change. (Incorporated by reference to Exhibit 18.1 of the Registrant's Amended Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2001, File No. 000-26823).
- \* 21.1 List of Subsidiaries.
- \* 23.1 Consent of Deloitte & Touche LLP regarding Form S-3, Registration No. 333-

85282

\* 23.2 Consent of Deloitte & Touche LLP regarding Form S-8, Registration No. 333-85258

\*Filed here with

## Unitholder Information

### Publicly-Traded Units

Alliance Resource Partners, L.P. is a publicly-traded master limited partnership.

Alliance Resource Partners, L.P. common units began trading on the Nasdaq National Market under the symbol "ARLP" in August of 1999. As of December 31, 2001, there were 15,405,311 common and subordinated units outstanding.

### Cash Distributions

Alliance Resource Partners, L.P. expects to make Minimum Quarterly Distributions of \$0.50 per common unit within 45 days after the end of each March, June, September and December to unitholders of record on the applicable record dates.

### Partnership Tax Details

- Unitholders are partners in the Partnership and receive cash distributions. The cash distributions are generally not taxable as long as the unitholder's tax basis remains above zero.
- A partnership is generally not subject to federal or state income tax. The annual income, gains, losses, deductions, or credits of the Partnership flow through to the unitholders, who are required to report their allocated share of these amounts on their individual tax returns, as though the unitholder had incurred these items directly.

- Unitholders of record will receive Schedule K-1 packages that summarize their allocated share of the Partnership's reportable tax items for the fiscal year. It is important to note that cash distributions received should not be reported as taxable income. Only the amounts provided on the Schedule K-1 should be entered on each unitholder's 2001 tax return.

- Should you have questions regarding the Schedule K-1 contact:

Alliance Resource Partners, L.P.  
K-1 Support  
P.O. Box 480927  
Denver, CO 80248  
(800) 485-6875  
Fax: (720) 931-7937

### Transfer Agent and Registrar

Unitholder requests regarding transfer of units, lost certificates, lost distribution checks or changes of address should be directed to:

American Stock Transfer and Trust Company  
Attn: Shareholder Services  
59 Maiden Lane-Plaza Level  
New York, NY 10038  
(800) 937-5449

### Additional Investor Information

Additional information about Alliance Resource Partners, L.P. can be obtained by contacting Investor Relations by e-mail at [fredric@arlp.com](mailto:fredric@arlp.com), telephone at (918) 295-7642, or writing to the Partnership's Mailing Address provided below.

### Partnership Offices

Alliance Resource Partners, L.P.  
1717 South Boulder Avenue  
Tulsa, OK 74119  
(918) 295-7600

### Partnership Mailing Address

P.O. Box 22027  
Tulsa, OK 74121-2027

### Independent Auditors

Deloitte & Touche LLP  
Two Warren Place  
6120 South Yale, Suite 1700  
Tulsa, OK 74136

### Officers and Directors

#### Joseph W. Craft III

President, Chief Executive Officer and Director

#### Robert G. Sachse

Executive Vice President and Director

#### Thomas L. Pearson

Senior Vice President – Law and Administration, General Counsel and Secretary

#### Michael L. Greenwood

Senior Vice President – Chief Financial Officer and Treasurer

#### Charles R. Wesley

Senior Vice President – Operations

#### Gary J. Rathburn

Senior Vice President – Marketing

#### John J. MacWilliams

Director

#### Preston R. Miller, Jr.

Director

#### John P. Neafsey

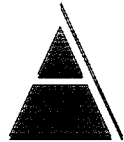
Director

#### John H. Robinson

Director

#### Paul R. Tregurtha

Director



**ALLIANCE RESOURCE  
PARTNERS, L.P.**

1717 South Boulder Avenue  
P.O. Box 22027  
Tulsa, Oklahoma 74121-2027

Contact:

Carolyn Fredrich

*Director – Investor Relations*

918-295-7642

fredric@arlp.com

Alliance Resource Partners, L.P.  
common units  
are traded on the Nasdaq National Market

**Ticker Symbol: ARLP**

**NASDAQ**  
LISTED

