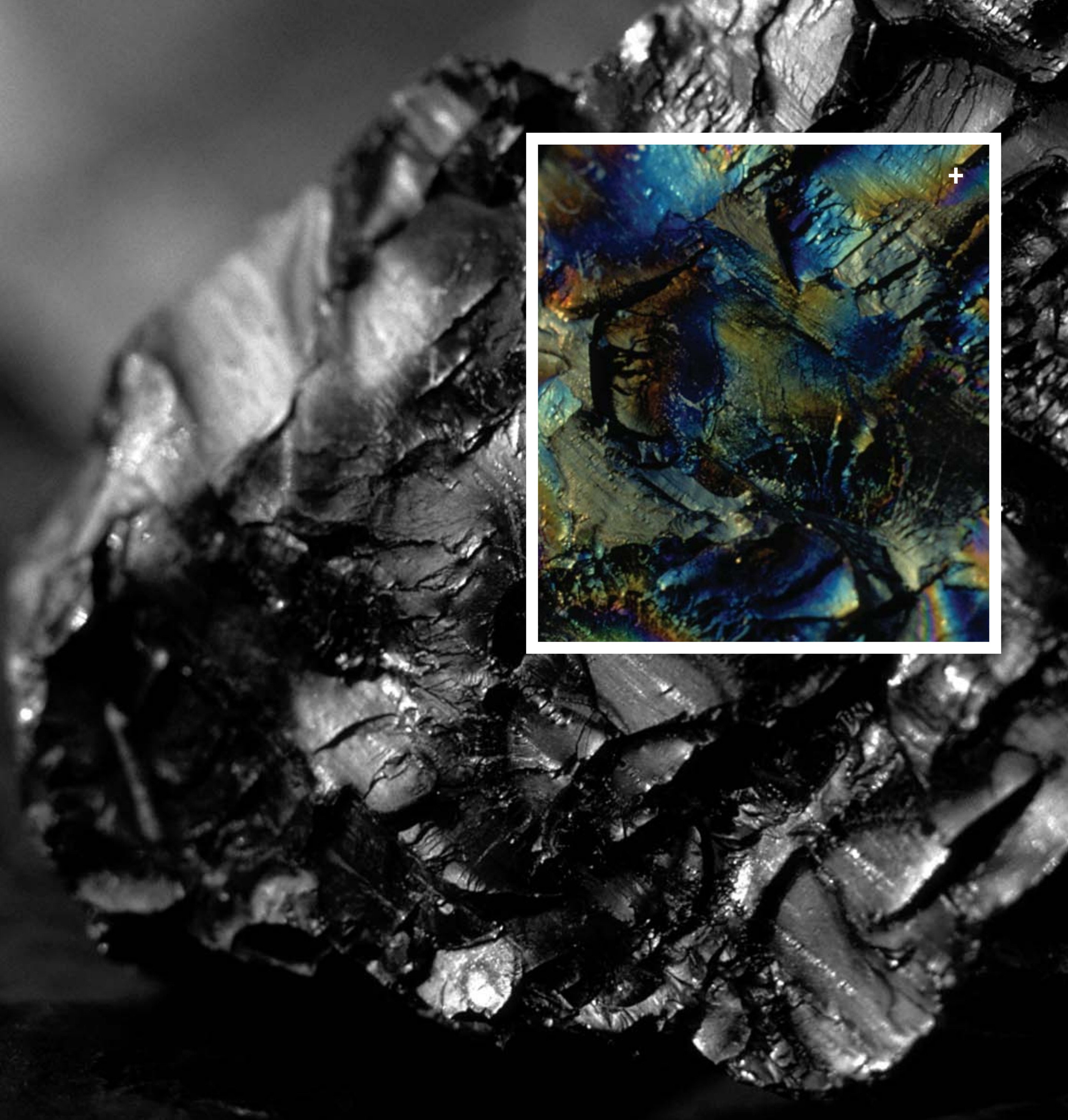
Performance. *Plus.*+



ALLIANCE RESOURCE PARTNERS, L.P. 2004 Annual Report and Form 10-K

Alliance Resource Partners, L.P. is the nation's only publicly traded master limited partnership involved in the production and marketing of coal. We have been a publicly traded partnership since August 1999 and are listed on the NASDAQ under the symbol "ARLP".

Financial Highlights millions except per unit amounts	**2004**	2003
Operating Data:		
Tons Sold	**20.8**	19.5
Tons Produced	**20.4**	19.2
Revenues Per Ton Sold(1)	**$ 29.98**	$ 26.83
Cost Per Ton Sold(2)	**$ 23.64**	$ 20.80
Financial Data:		
Revenues	**$ 653.3**	$ 542.7
Income From Operations	**$ 78.3**	$ 49.1
Net Income	**$ 76.6**	$ 47.9
Basic Net Income Per LP Unit(3)	**$ 4.09**	$ 2.71
Diluted Net Income Per LP Unit(3)	**$ 3.98**	$ 2.62
Total Assets	**$ 412.8**	$ 336.5
Total Debt	**$ 180.0**	$ 180.0
Net Cash Provided By Operating Activities	**$ 145.1**	$ 110.3

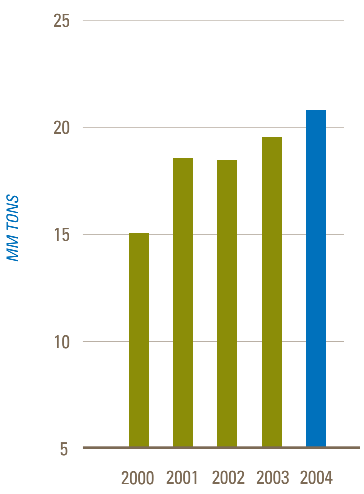
(1) See Note (4) on page 32 of 2004 Form 10-K for revenues per ton sold definition.
(2) See Note (5) on page 32 of 2004 Form 10-K for cost per ton sold definition.
(3) The weighted average basic units outstanding for the years ended December 31, 2004 and 2003, were, 17,940,948 and 17,580,734, respectively, and on a fully diluted basis, were 18,437,168 and 18,162,839, respectively.

Alliance Resource Partners, L.P.

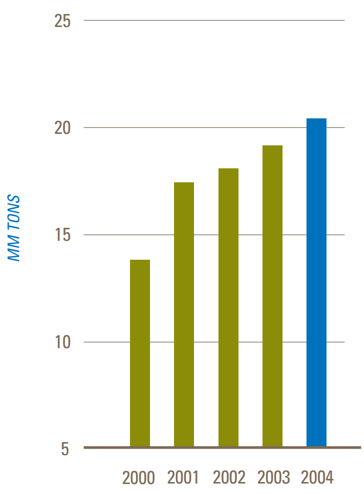
Core strengths and investment highlights

- Geographic and product diversity
- Efficient, low-cost operator since 1971
- Consistent track record for growth and market performance
- Long-term relationships with major electric utilities and industrial customers
- Coal marketed from three of the four major U.S. coal producing regions
- Sixth largest coal producer in the eastern U.S.

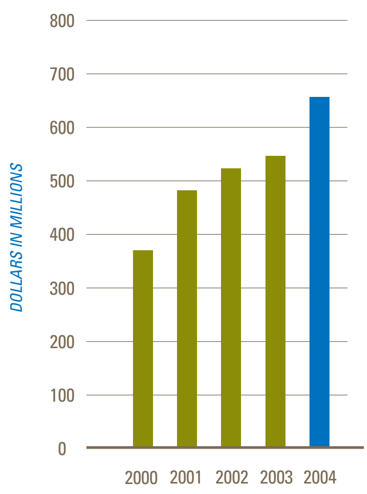
TONS OF COAL SOLD
2000 -2004



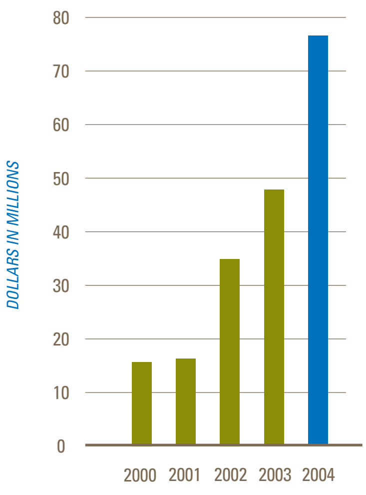
TONS OF COAL PRODUCED
2000 -2004



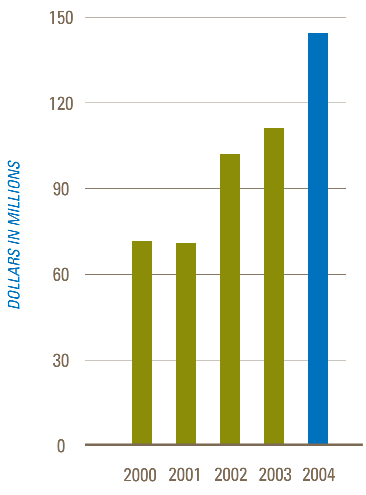
REVENUES
2000 -2004



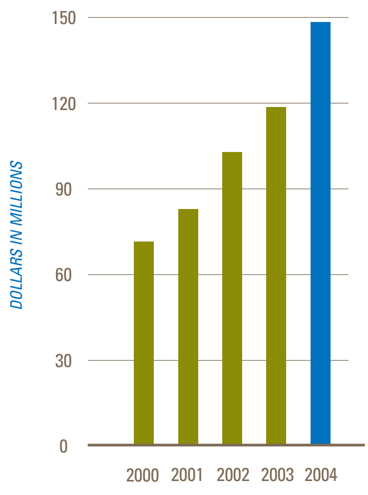
NET INCOME(4)
2000 -2004



CASH FLOW FROM OPERATIONS
2000 -2004



EBITDA(5)
2000 -2004



(4) Net Income for 2001 includes $7.9 million for the cumulative effect of the change in the method of estimating coal workers black lung benefits liability effective January 1, 2001.
(5) See Note (6) on page 32 of 2004 Form 10-K for EBITDA definition, a reconciliation of EBITDA to Net Income and Management's reason why disclosure of EBITDA is useful to investors.

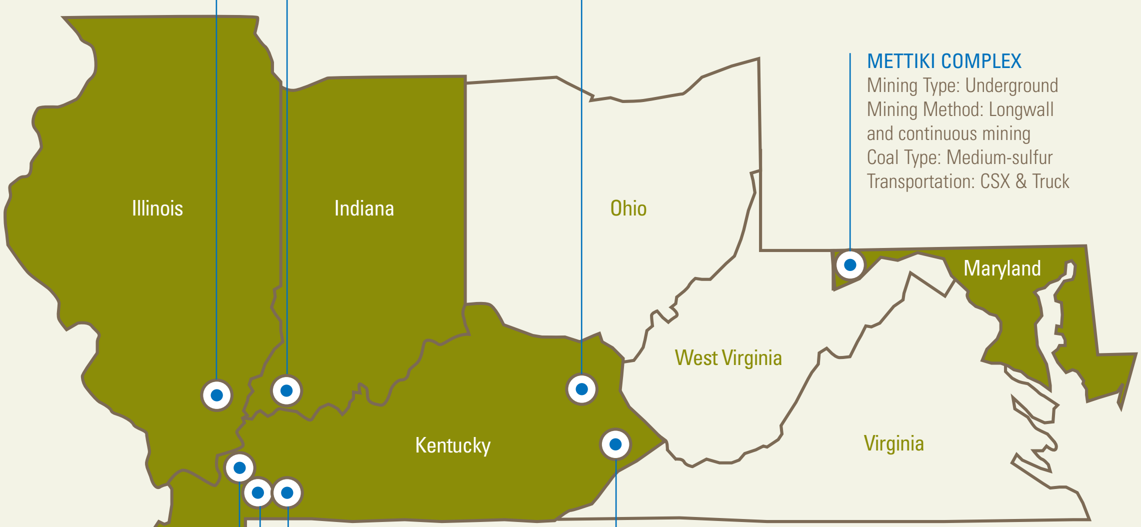
Alliance Resource Partners, L.P. Coal Mining Complexes

GIBSON COMPLEX
Mining Type: Underground
Mining Method: Continuous mining
Coal Type: Low-sulfur
Transportation: Truck & Barge

PATTIKI COMPLEX
Mining Type: Underground
Mining Method: Continuous mining
Coal Type: High-sulfur
Transportation: CSX & Barge

PONTIKI COMPLEX
Mining Type: Underground
Mining Method: Continuous mining
Coal Type: Low-sulfur
Transportation: NS & Truck

METTIKI COMPLEX
Mining Type: Underground
Mining Method: Longwall and continuous mining
Coal Type: Medium-sulfur
Transportation: CSX & Truck



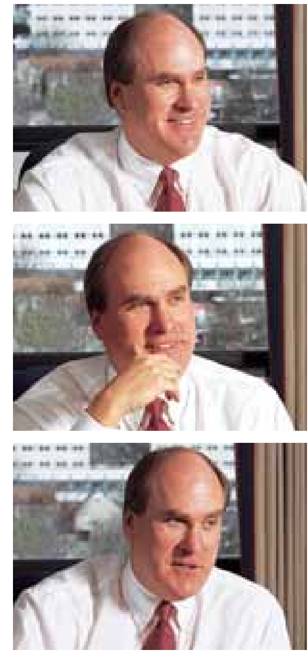
DOTIKI COMPLEX
Mining Type: Underground
Mining Method: Continuous mining
Coal Type: High-sulfur
Transportation: CSX, PAL, Truck & Barge

MC MINING COMPLEX
Mining Type: Underground
Mining Method: Continuous mining
Coal Type: Low-sulfur
Transportation: CSX & Truck

HOPKINS COMPLEX
Mining Type: Surface
Mining Method: Contour, truck and shovel, and dragline area mining
Coal Type: High-sulfur
Transportation: CSX, PAL & Truck

Elk Creek Mine (Under construction)
Mining Type: Underground
Mining Method: Continuous mining
Coal Type: High-sulfur

WARRIOR COMPLEX
Mining Type: Underground
Mining Method: Continuous mining
Coal Type: High-sulfur
Transportation: CSX, PAL & Truck



Joseph W. Craft III
President and
Chief Executive Officer

To Our Fellow Unitholders:

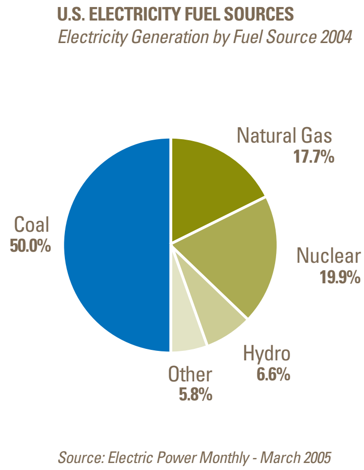
Alliance Resource Partners reached an important milestone in 2004 as we celebrated our fifth anniversary as a publicly traded partnership. At the time of our initial NASDAQ listing in August 1999, the coal industry was faced with a challenging market environment and a perception that competing fuels – particularly natural gas – were preferable to coal. Over the last five years, however, natural gas prices have more than tripled and are currently forecasted to remain near historically high levels for the foreseeable future. As a result, the current market environment for coal is strong and the outlook is bright.

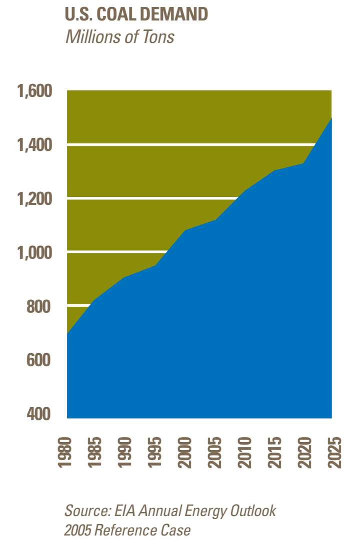
Clean-burning, abundant, low-cost coal is now considered the fuel of choice to meet America's electricity needs today and in the future. Current market fundamentals, including a stronger economy, low utility stockpiles, supply constraints and environmental compliance initiatives by power generators, have created significant opportunities for the coal industry. As evidenced by our performance, Alliance Resource Partners has effectively capitalized on this favorable shift in the market. Consider the following results we achieved during 2004:

- Completed our fourth consecutive year of record profits
- Achieved record results for revenues, net income, EBITDA, cash flow from operations, production tons and tons sold
- Provided unitholders with a total return of more than 127 percent
- Increased distributions to unitholders 33 percent over 2003
- Recorded a 115 percent increase in unit price over the prior year.

With these results, Alliance Resource Partners is a performance leader in the master limited partnership sector and among the most profitable publicly traded coal companies in America.

Alliance Resource Partners has consistently delivered sterling performance, plus much more.





Delivery. *Plus.*+ {CUSTOMERS}

Anticipating our customers' growing demand for coal, in October 2004 Alliance Resource Partners acquired 100 million tons of reserves through two separate coal leases.

SETTING RECORDS

Our 2004 net income increased 60 percent to a record $76.6 million, or $4.09 per basic limited partnership unit, compared with $47.9 million, or $2.71 per unit, in 2003. These results are consistent with our past performance as Alliance Resource Partners' net income has increased at a compounded annual growth rate of 67 percent since 2001.

Our 2004 revenues totaling $653.3 million also broke previous records. We achieved this 20 percent increase over 2003 revenues, in part, by increasing production and coal sales volumes to capitalize on continued improvement in coal market prices. Our average coal sales price per ton realized during 2004 jumped $3.02 compared with prices one year ago.

Alliance Resource Partners' 2004 EBITDA[5] – or income before net interest expense, income taxes and depreciation, depletion and amortization –was $147.9 million, reflecting a 25 percent compounded annual growth rate since 2001.

In recognition of our consistent, strong financial performance, we were once again listed as one of the nation's fastest growing companies in *Business Week* magazine's 2004 ranking of "100 Hot Growth Companies." The list is compiled from publicly traded companies with annual sales between $50 million and $1.5 billion and is based on three-year results in sales growth, earnings growth and return on invested capital. Alliance Resource Partners jumped to number 26 on the list in 2004 after debuting at number 83 in 2003.

SHARING PROFITS

Our primary objective is to achieve sustainable, capital-efficient growth in cash flow that will allow us to increase distributions to our unitholders. We have consistently delivered on this objective by increasing distributions to unitholders 50 percent since 2001. Our performance during 2004 was especially notable: Alliance Resource Partners increased quarterly cash distributions for the fourth quarter of 2004 to 75 cents per unit, up more than 33 percent over the 2003 fourth quarter distribution of 56.25 cents per unit.

DELIVERING RESULTS

Robust coal market conditions enabled Alliance Resource Partners to sell a record 20.8 million tons of coal in 2004, up 7 percent over 2003. As coal market fundamentals remain strong, Alliance Resource Partners intends to increase coal production in 2005 to an estimated 22.2 to 22.5 million tons. Substantially all of our estimated 2005 production is already committed under existing coal sales agreements. For 2006, we are expecting to produce 23.0 to 23.5 million tons of coal.

Dedication. *Plus.*+ {EMPLOYEES}

Throughout the year, our employees consistently demonstrated their ability to successfully respond to opportunities and challenges.

We produce a diverse range of steam coals, satisfying a broad range of customer specifications. Ongoing efforts to optimize capacity and improve efficiencies allow Alliance Resource Partners to take advantage of market opportunities. The following 2004 operational highlights illustrate how we have grown to become the sixth largest coal producer in the eastern United States:

- Invested $54.7 million in capital expenditures to expand our operating capacity, enhance our efficiency and maintain our assets
- Signed agreements with two third-party contract mining companies to produce coal from reserves that we control near our Mettiki complex. Deliveries began in July, increasing annual production by approximately 625,000 tons
- Installed additional equipment at our Gibson County, Dotiki and Pattiki mines to increase their production capabilities
- Restarted operations at our Newcoal surface mine in response to requirements from existing customers and increased demand for Illinois Basin coal.

In 2004, these actions helped Alliance Resource Partners capitalize on promising growth and profit opportunities. Additionally, while Alliance Resource Partners' production has grown at a 5 percent compounded annual growth rate since 2001 – based upon our view of the coal markets and anticipated demand for our product – our goal is to increase production at an 8 percent to 9 percent annual rate going forward.

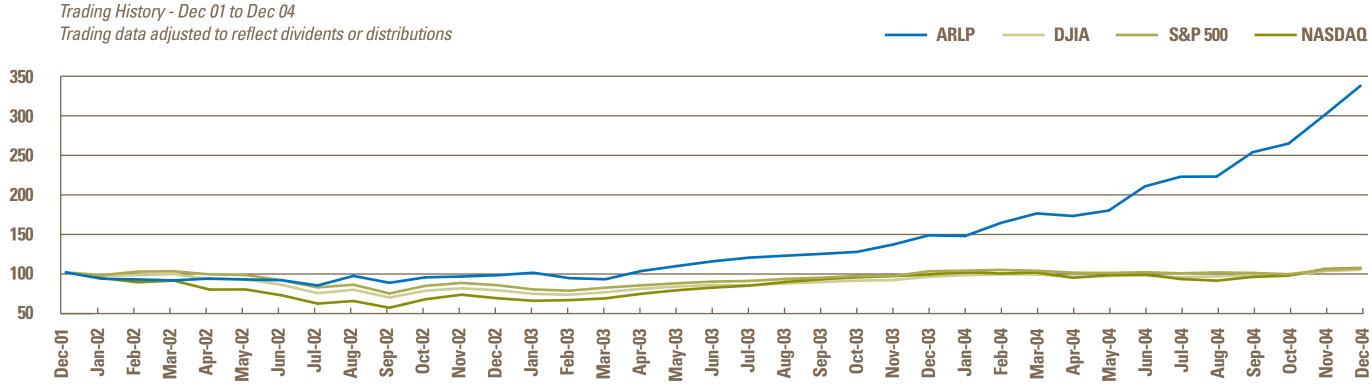
We intend to continue our efforts to maximize operating capacity and optimize the performance of our assets in the future. For 2005, we have set a $79.9 million capital expenditure budget, which includes maintenance capital and equipment additions. Anticipated expenditures include the opening of the Elk Creek mine, addition of a fourth continuous mining unit at the Warrior complex, equipment additions at the Pattiki mine, transitioning the Pontiki mine to the Van Lear seam reserve and infrastructure improvements at the Warrior, Gibson County and Mt. Vernon transfer terminal operations. These strategic investments will allow Alliance Resource Partners to continue moving forward with speed, flexibility and innovation.

TESTING METTLE

After more than 33 years of relatively smooth operations, adversity struck twice during 2004.

On February 11, our Dotiki mine was idled following a mine fire that originated with a diesel supply trailer. This underground complex employs approximately 360 workers.

MARKET PERFORMANCE COMPARISON
Trading History - Dec 01 to Dec 04
Trading data adjusted to reflect dividents or distributions



Growth. *Plus.*+ {UNITHOLDERS}

During 2004, Alliance Resource Partners provided a total return to unitholders of more than 127 percent.

On December 25, a fire was discovered near the bottom of the slope at our Excel No. 3 mine which resulted in the mine being idled the following day. This underground complex employs approximately 250 workers.

We are grateful that not one injury resulted to anyone involved in either of these around-the-clock firefighting and mine recovery efforts. Safety is more than a priority at Alliance Resource Partners; it is the way we do business. The extensive safety procedures and training our employees practice every day save lives and minimize damages.

RECOVERY

We are indebted to our employees, our business partners, the local communities, the U.S. Mine Safety and Health Administration (MSHA), and the Kentucky Office of Mine Safety and Licensing for their unwavering support and assistance in implementing state-of-the art firefighting and mine recovery plans. As a result of cooperative efforts and teamwork, we achieved mine recovery results never before seen in the coal mining industry. Both mines reopened safely and successfully in record time: Dotiki resumed production only 28 days after the fire occurred, and initial production resumed at Excel No. 3 less than 60 days after the fire was discovered.

David Lauriski, former assistant secretary of labor for MSHA, called the Dotiki recovery "a case-book example of how cooperation, technology and quick decision-making can contribute to the speedy recovery of mine fires." John Correll, deputy assistant secretary of labor for MSHA, hailed the recovery of Excel No. 3 as an example of how "working together toward a common objective, industry and government…[can safely return] miners to their jobs." Alliance Resource Partners is cooperating with MSHA's Technical Support Department to refine the mine recovery methods used at Dotiki and Excel in order to benefit the entire coal industry.

FUELING GROWTH

In October 2004, Alliance Resource Partners announced the addition of 100 million tons of high-sulfur coal through leases of the Elk Creek and Tunnel Ridge reserves. These leases increased our reserve base to more than 512 million tons and provide us the opportunity to develop two new large scale mining operations.

Results. *Plus.*+ {WALL STREET}

Alliance Resource Partners is a performance leader in the MLP sector and among the most profitable publicly traded coal companies in America.

Development of the Elk Creek reserves, located in Hopkins County, Kentucky, is underway and we expect initial production to begin by the end of 2005. In January 2005, we completed the lease of the Tunnel Ridge reserves, which are located in West Virginia and Pennsylvania, and have begun efforts to permit the property and secure coal supply agreements. Assuming these efforts are successful, we currently estimate that initial production at Tunnel Ridge could begin in the 2008 – 2009 timeframe.

Alliance Resource Partners also recently announced that we have begun permitting the Gibson County South reserve area, which is located near our current Gibson County mining complex in Indiana. Gibson County South contains an estimated 83 million tons of high quality Illinois Basin coal. Assuming permits can be obtained on a timely basis and adequate coal supply agreements can be secured, we currently anticipate bringing this property into production in the 2008 – 2009 timeframe.

All of these projects reflect our commitment to growth and our focus on the acquisition and development of high-sulfur coal reserves in the Illinois Basin and Northern Appalachia producing regions of the U.S.

SEIZING OPPORTUNITY

In response to legislative and regulatory initiatives, electric utilities have already announced plans to add approximately 30 gigawatts of new scrubbed capacity over the next four years. As utilities continue to develop their environmental compliance strategies, some industry experts estimate as much as 100 gigawatts of new scrubbed capacity could be operational by 2008.

With the installation of these scrubbers, power generators will be able to cleanly and efficiently burn higher sulfur coal. We believe this will result in a substantial swing in market demand from low sulfur to high sulfur coal. We are positioning Alliance Resource Partners to take advantage of what we believe is a significant shift in market opportunity.

LOOKING AHEAD

The outlook for Alliance Resource Partners is positive and promising. The fundamentals of the coal industry have never been better. Coal continues to be the fuel of choice for baseload electricity generation – more than 50 percent of America's electricity is fueled by coal – and demand for

electricity is growing. Domestic coal is dependable, it's reliable, it's abundant and it's being burned cleaner every day. Competing fuels – natural gas and oil – are trading near all-time high prices. In addition, international demand for coal is strong as global economies, particularly China and India, continue to experience significant growth and increased demand for energy.

Alliance Resource Partners has built a strong track record and we are focused on future growth in earnings and distributions. Our business is strong and I believe we are well positioned to continue our trend of record-setting results.

SALUTING HEROES

In closing, I especially want to thank the more than 2,000 American heroes of Alliance Resource Partners. Throughout the past year, our employees consistently demonstrated their ability to successfully respond to opportunities and challenges. Through their efforts, Alliance Resource Partners once again delivered superior results, plus much more. I applaud their determination, dedication, teamwork, integrity and commitment to excellence.

Joseph W. Craft III
President and
Chief Executive Officer

April 21, 2005

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

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004

OR

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

FOR THE TRANSITION PERIOD FROM _______________ TO _____________

COMMISSION FILE NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

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

1717 SOUTH BOULDER AVENUE, SUITE 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 [X] No [ ]

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

Yes [X] No [ ]

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $465,898,654 as of June 30, 2004, the last business day of the registrant's most recently completed second fiscal quarter, based on $46.66 per unit, the closing price of the common units as reported on the Nasdaq National Market on such date.

As of March 15, 2005, 18,130,440 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements. 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 prices, which could adversely affect our operating results and cash flows;
- deregulation of the electric utility industry 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 of existing contracts;
- customer bankruptcies and/or cancellations of, or breaches to existing contracts;
- customer delays or defaults in making payments;
- fluctuations in coal demand, prices and availability due to labor and transportation costs and disruptions, equipment availability, governmental regulations and other factors;
- our productivity levels and margins that we earn on our coal sales;
- any unanticipated increases in labor costs, adverse changes in work rules, or unexpected cash payments associated with post-mine reclamation and workers’ compensation claims;
- any unanticipated increases in transportation costs and risk of transportation delays or interruptions;
- greater than expected environmental regulation, costs and liabilities;
- a variety of operational, geologic, permitting, labor and weather-related factors;
- risk of major mine-related accidents, such as mine fires, or interruptions;
- results of litigation;
- difficulty maintaining our surety bonds for mine reclamation as well as workers’ compensation and black lung benefits; and
- difficulty obtaining commercial property insurance, and risks associated with our current 10.0% participation (excluding any applicable deductible) in our commercial insurance property program.

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

You should consider the information above when reading any forward-looking statements contained:

- in this Annual Report on Form 10-K;
- other reports filed by us with the SEC;
- our press releases; and
- written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

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 what we believe to be the sixth largest coal producer in the eastern United States. At December 31, 2004, we had approximately 442.4 million tons of reserves in Illinois, Indiana, Kentucky, Maryland and West Virginia. In 2004, we produced 20.4 million tons of coal and sold 20.8 million tons of coal. The coal we produced in 2004 was 32.3% low-sulfur coal, 15.7% medium-sulfur coal and 52.0% high-sulfur coal. In 2004, approximately 88% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices, also known as "scrubbers," to remove sulfur dioxide. We classify low-sulfur coal as coal with a sulfur content of less than 1%, medium-sulfur coal as coal with a sulfur content between 1% and 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

At December 31, 2004, we operated seven underground mining complexes and one surface operation in Illinois, Indiana, Kentucky and Maryland. Our mining activities are organized into three operating regions: (a) the Illinois Basin operations, (b) the East Kentucky operations, and (c) the Maryland operations. At our Warrior Complex, we host and operate a coal synfuel facility, supply the facility with coal feedstock, assist with the marketing of coal synfuel and provide other services to the owner of the synfuel facility. In January 2005, we entered into several agreements to provide similar services for a synfuel facility to be located at our Gibson Complex and entered into three short-term agreements to provide coal feedstock to a synfuel facility located at the power plant of the Mettiki Complex's primary customer. We have no reportable segments because our operations solely consist of producing and marketing coal and providing rental and service fees associated with producing and marketing coal synfuel.

We and our subsidiary, Alliance Resource Operating Partners, L.P. (the intermediate partnership), are Delaware limited partnerships formed to acquire, own and operate certain coal production and marketing assets of Alliance Resource Holdings, Inc. (Alliance Resource Holdings), a Delaware corporation formerly known as Alliance Coal Corporation. We completed our initial public offering in August 1999, at which time Alliance Resource Holdings contributed certain assets in exchange for cash, common and subordinated units, general partner interests, the right to receive incentive distributions as defined in the partnership agreement and the assumption of related indebtedness.

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 interest in us. Our limited partners, including the general partners as holders of common units, own an aggregate 98% limited partner interest in us.

Our internet address is www.arlp.com, and we make available on our internet website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and Form 4s for our Section 16 filers (and amendments and exhibits, such as press releases, to such filings) as soon as reasonably practicable after we electronically file with or furnish such material to the Securities and Exchange Commis-sion. Our "Code of Ethics" for our chief executive officer and our senior financial officers is also posted on our website.

Recent Development

MC Mining Mine Fire. On December 26, 2004 the MC Mining Excel No. 3 mine was temporarily idled following the occurrence of a mine fire (the MC Mining Fire Incident). The fire was discovered by mine personnel near the bottom of the Excel No. 3 mine slope late in the evening of December 25, 2004.

Under a firefighting plan developed by MC Mining, in cooperation with mine emergency response teams from the Mine Safety and Health Administration and Kentucky Office of Mine Safety and Licensing, the four portals at the Excel No. 3 mine were capped to deprive the fire of oxygen. A series of boreholes were then drilled into the fire area to further suppress the fire. As a result of these efforts, the mine atmosphere was rendered substantially inert, or without oxygen, and the Excel No. 3 mine fire was effectively suppressed. MC Mining then began construction of temporary and permanent barriers designed to completely isolate the mine fire area. When construction of the permanent barriers was completed, MC Mining began efforts to repair and rehabilitate the Excel No. 3 mine infrastructure. On February 21, 2005, the repair and rehabilitation efforts had progressed sufficiently to allow initial resumption of production. We anticipate that MC Mining may return to full production by the end of the first quarter of 2005, but we cannot assure that our ability to produce will not continue to be adversely impacted by the MC Mining Fire Incident for a period of time.

We maintain commercial property (including business interruption) insurance policies, which provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles and 10% co-insurance, but we cannot give any assurances as to the eventual timing or amount of any recovery of proceeds under these policies. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations; Summary" for a description of the preliminary cost estimates and the financial impact on our 2004 results.

2004 Events

Elk Creek and Tunnel Ridge. On October 21, 2004, we announced an agreement, subject to finalization of definitive agreements, to enter into two separate coal leases, which cumulatively will increase our coal reserve holdings by 25%. The Elk Creek reserves (Elk Creek) are located in Hopkins County, Kentucky, and the Tunnel Ridge reserves (Tunnel Ridge) are located in Ohio County, West Virginia and Washington County, Pennsylvania. These leases are estimated to contain approximately 100 million tons of high-sulfur coal reserves. The lessor for both leases is our special general partner. We also announced plans to immediately begin the development process for these properties, which includes obtaining the necessary mining permits and securing sufficient coal sales commitments to justify the capital investment needed to bring these properties into production.

The Elk Creek reserve area encompasses approximately 9,000 acres and is contiguous to our Hopkins County Coal complex. The Elk Creek coal reserves are currently estimated to include approximately 30 million tons of high-sulfur coal. The Elk Creek mine will be an underground mining complex that mines the West Kentucky No. 9 and No. 11 coal seams. We will use continuous mining units, and employ room-and-pillar mining techniques. We intend to use the existing coal handling and other surface facilities owned by Hopkins County Coal. We anticipate the Elk Creek complex will employ as many as 250 individuals and produce up to 3.2 million tons of coal annually. We estimate total capital expenditures to develop Elk Creek to be approximately $65.0 million. In December, 2004, the board of directors of our managing general partner approved the capital expenditures associated with Elk Creek. Coal supply commitments are currently being pursued. Construction of the Elk Creek mining complex began in the first quarter of 2005. We expect to fund these capital expenditures with available cash and marketable securities on hand, future cash generated from operations and/or borrowings available under our revolving credit facility.

In December 2000, Hopkins County Coal entered into an option agreement to lease and/or sublease the Elk Creek reserves from our special general partner. Under the terms of the option to lease and sublease, Hopkins County Coal paid an option fee of $645,000 during the year ended December 31, 2000, and paid option fees of $684,000 during each of the years ended December 31, 2001, 2002 and 2004. The 2003 option fee of $684,000 was paid in January 2004. Upon exercise of the option to lease or sublease, Hopkins County Coal is obligated to make an additional five annual advance minimum royalty payments of $684,000 per year, which royalty is fully recoupable against earned royalties. The earned royalty rate under the lease and/or sublease is $0.25 per ton.

In January 2005, we acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC for approximately $500,000 and the assumption of reclamation liabilities from Alliance Resource Holdings, Inc., a company owned by our management. Tunnel Ridge, LLC controls through a coal lease agreement with the special general partner an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. The Tunnel Ridge reserve area encompasses approximately 50,571 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge, LLC began paying our special general partner an advance minimum royalty of $3.0 million per year, which advance royalty payments will be fully recoupable against earned royalties. The earned royalty rate under the coal lease is the greater of $0.75 per ton or 3.0% of the per ton gross sales price f.o.b. barge. The term of the coal lease is the earlier of 30 years or until exhaustion of all mineable and merchantable coal. We have termination rights after the initial four years of the coal lease.

Tunnel Ridge, LLC also controls, under a separate lease agreement with our special general partner, the rights to approximately 900 acres of surface land and other tangible assets. Under the terms of the lease agreement, Tunnel Ridge, LLC shall pay our special general partner an annual lease payment of $240,000 beginning January 1, 2005. The lease agreement has an initial term of four years, which term may be extended by Tunnel Ridge, LLC, at the same annual lease payment rate, to be consistent with the term of the coal lease.

We have initiated the permitting process for the Tunnel Ridge reserve area.We anticipate the Tunnel Ridge operation will use a longwall miner for the majority of its coal extraction as well as continuous mining units for preparation of the mine for future longwall mining. We estimate the Tunnel Ridge operation will be designed to produce up to six million tons of coal annually. We believe production from Tunnel Ridge may begin as early as 2008. We anticipate the Tunnel Ridge complex will employ as many as 300 individuals. We estimate total capital expenditures required to develop Tunnel Ridge to be approximately $200 million over a five-year period. We currently expect to fund these capital expenditures with available cash and marketable securities, future cash generated from operations and/or borrowings available under our revolving credit facility. Definitive development commitment for Tunnel Ridge is dependent upon final approval by the board of directors of our managing general partner.

The Elk Creek and Tunnel Ridge transactions described above are related-party transactions and, as such, were reviewed by the board of directors of our managing general partner and its conflicts committee. Based upon these reviews, it was determined that these transactions reflect market-clearing terms and conditions customary in the coal industry. As a result, the board of directors of our managing general partner and its conflicts committee approved the Elk Creek and Tunnel Ridge transactions as fair and reasonable to us.

Conversion of Subordinated Units. As of September 30, 2004, we satisfied the final conversion financial tests for converting the remaining subordinated units into common units as provided for under applicable provisions in the Partnership Agreement. On October 21, 2004, our board of directors of our managing general partner and its conflicts committee approved management's determination that such final conversion financial tests were satisfied as of September 30, 2004. As a result, the remaining outstanding subordinated units (i.e., 3,211,266 subordinated units) held by our special general partner were converted into common units on November 2, 2004.

Dotiki Fire Incident. On February 11, 2004, Webster County Coal, LLC's (Webster County Coal) Dotiki mine was temporarily idled for a period of twenty-seven calendar days following the occurrence of a mine fire that originated with a diesel supply tractor (the Dotiki Fire Incident). As a result of the firefighting efforts of the Mine Safety and Health Administration, Kentucky Department of Mines and Minerals, and Webster County Coal personnel, Dotiki successfully extinguished the fire and totally isolated the affected area of the mine behind permanent barriers. Initial production resumed on March 8, 2004. For the Dotiki Fire Incident, we had commercial property insurance that provided coverage for damage to property destroyed, interruption of business operations, including profit recovery, and expenditures incurred to minimize the period and total cost of disruption to operations. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations; Summary" for a description of the accounting treatment of expenses and insurance proceeds associated with the Dotiki Fire Incident.

Mining Operations

We produce a diverse range of steam coals with varying sulfur and heat contents, which enables us to satisfy the broad range of specifications required by our customers. The following chart summarizes our coal production by region for the last five years.

Operating Regions and Complexes	**2004**	**2003**	**2002**	**2001**	**2000**
(tons in millions)					
Illinois Basin Operations:					
Dotiki, Warrior, Pattiki, Hopkins, Gibson Complexes	13.6	12.3	12.1	11.9	8.4
East Kentucky Operations:					
Pontiki, MC Mining Complexes	3.6	3.6	3.0	2.8	2.7
Maryland Operations:					
Mettiki Complex	3.2	3.3	2.9	2.7	2.6
Total	20.4	19.2	18.0	17.4	13.7

Illinois Basin Operations. Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. We have approximately 1,200 employees in the Illinois Basin and currently operate five mining complexes. Additionally, we host a coal synfuel facility at one of our mining complexes.

Dotiki Complex. Webster County Coal, LLC operates Dotiki, which is an underground mining complex located near the city of Providence in Webster County, Kentucky. The complex was opened in 1966, and we purchased the mine in 1971. Our Dotiki complex utilizes continuous mining units employing room-and-pillar mining techniques. In 2004, Dotiki increased mining capacity with the addition of two continuous miners. Also in 2004, the preparation plant throughput capacity was increased by 30% from 1,000 tons of raw coal to 1,300 tons of raw coal an hour. Capacity was increased principally to accommodate a change in customer requirements for washed coal rather than raw coal.

On February 11, 2004, the Dotiki mine was temporarily idled following the occurrence of a mine fire. The fire was successfully extinguished and the affected area of the mine was totally isolated behind permanent barriers. Production resumed on March 8, 2004. For information on the fire at our Dotiki mine, please see "2004 Events – Dotiki Fire Incident" above.

Production of high-sulfur coal from the complex is shipped via the CSX and PAL railroads and by truck on U.S. and state highways. Our primary customers for coal produced at Dotiki are Louisville Gas & Electric (LG&E), Seminole Electric Cooperative, Inc. (Seminole) and Tennessee Valley Authority (TVA), all of which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units.

Warrior Complex. Warrior Coal, LLC operates the Cardinal mine, an underground mining complex located near Madisonville, in Hopkins County, Kentucky, between and adjacent to our other western Kentucky operations. The Warrior complex was opened in 1985 and acquired by us in February 2003. Warrior utilizes continuous mining units employing room-and-pillar mining techniques producing high-sulfur coal. Warrior's preparation plant has a throughput capacity of 600 tons of raw coal an hour.

Warrior sells substantially all of its production to Synfuel Solutions Operating, LLC (SSO) for feedstock in the production of coal synfuel, as discussed below. SSO's coal synfuel production facility was moved from Hopkins County Coal, LLC (Hopkins) to Warrior in April 2003. Warrior's production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways. Additionally, Warrior purchased supplemental production from Dotiki and a third-party supplier for resale to SSO and will continue to purchase tons from the third-party supplier through June 2007. SSO continues to ship coal synfuel to electric utilities that have been purchasers of our coal. We maintain "back-up" coal supply agreements with these long-term customers for our coal, which automatically provide for the sale of our coal to them in the event they do not purchase coal synfuel from SSO.

We have entered into long-term agreements with SSO to host and operate its coal synfuel facility currently located at Warrior, supply the facility with coal feedstock, assist SSO with the marketing of coal synfuel and provide other services. These agreements expire on December 31, 2007 and provide us with coal sales, rental and service fees from SSO based on the synfuel facility throughput tonnages. These amounts are dependent on the ability of SSO's members to use certain qualifying tax credits applicable to the facility. As discussed above, we sell most of the coal produced at Warrior to SSO, while Alliance Coal Sales, a division 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 revenues associated with the coal synfuel production facility cannot be assured. However, we have maintained "back up" coal supply agreements with each coal synfuel customer that automatically provide for sale of our coal to these customers in the event they do not purchase coal synfuel from SSO. In conjunction with a decision to relocate the coal synfuel production facility to Warrior, agreements for providing certain of these services were assigned to Alliance Service, Inc. (Alliance Service), a wholly-owed subsidiary of Alliance Coal, in December 2002. Alliance Service is subject to federal and state income taxes.

For 2004, the incremental annual net income benefit from the combination of the various coal synfuel-related agreements associated with the facility located at Warrior was approximately $16.9 million, assuming that coal pricing would not have increased without the availability of synfuel. The continuation of the incremental net income benefit associated with SSO's coal synfuel facility cannot be assured. We earn income by supplying SSO's synfuel facility with coal feedstock, assisting SSO with the marketing of coal synfuel, and providing rental and other services. Pursuant to our agreement with SSO, we are not obligated to make retroactive adjustments or reimbursements if SSO's tax credits are disallowed.

In June 2003, the Internal Revenue Service (IRS) suspended the issuance of private letter rulings on the significant chemical change requirement to qualify for synfuel tax credits and announced that it was reviewing the test procedures and results used by taxpayers to establish that a significant chemical change had occurred. In October 2003, the IRS completed its review and concluded that the test procedures and results were scientifically valid if applied in a consistent and unbiased manner. The IRS has resumed issuing private letter rulings under its existing guidelines. SSO has advised us that its private letter ruling could be reviewed by the IRS as part of a tax audit, similar to the IRS reviews of other synfuel procedures. SSO has also advised us that the Permanent Subcommittee on Investigations of the Senate Committee on Governmental Affairs (Subcommittee) is reviewing the synfuel industry, that the Subcommittee has indicated that they hope to interview almost all taxpayers that are involved in the synfuel business and that SSO has been requested to meet informally with the Subcommittee to help enhance the Subcommittee's knowledge of the synfuel industry.

Pattiki Complex. White County Coal, LLC operates Pattiki, which is an underground mining complex located near the city of Carmi, in White County, Illinois. We began construction of the complex in 1980 and have operated it since its inception. Our Pattiki complex utilizes continuous mining units employing room-and-pillar mining techniques. During 2004, Pattiki increased mining capacity with the addition of one continuous miner. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour.

Production of high-sulfur coal from the complex is shipped via the CSX railroad. Our primary customers for coal produced at Pattiki are Ameren Energy Fuels & Services Company, Northern Indiana Public Service Company (NIPSCO) and Seminole for use in their generating units. NIPSCO and Seminole have scrubbed generating units.

Hopkins Complex. Hopkins County Coal, LLC operates a mining complex consisting of one active surface mine, one undeveloped surface mine, and the Elk Creek reserves that are being prepared for development in 2005. Hopkins County Coal is located near the city of Madisonville in Hopkins County, Kentucky. We acquired the complex in January 1998. The active surface mine was idled in June 2003 because we were unable to secure sufficient sales commitments in the Illinois Basin region. In October 2004, the surface mine was re-opened in response to incremental sale opportunities from existing customers as well as strong market demand for Illinois Basin region coal. We anticipate the active surface mine will deplete its coal reserves at the end of 2005.

The surface operation utilizes dragline mining and the preparation plant has a throughput capacity of 1,000 tons of raw coal an hour. Historically, Hopkins' production has the ability to be shipped via the CSX and PAL railroads and by truck on U.S. and state highways.

On October 21, 2004, we announced our intent to exercise an option to lease the Elk Creek reserves located in Hopkins County, Kentucky. The Elk Creek coal reserves consist of approximately 30 million tons of high-sulfur coal. The Elk Creek mine will be an underground mining complex, using continuous mining units employing room-and-pillar mining techniques. We intend to utilize the existing coal handling and other surface facilities at Hopkins to process and ship the Elk Creek coal. Construction of the Elk Creek complex commenced in the first quarter of 2005 with estimated capital expenditures of $65 million of which approximately $13.5 million is anticipated to be incurred in 2005. Initial production is expected to begin in early 2006 with anticipated annual production of 3.2 million tons. For more information, please see "2004 Events" above.

Gibson Complex. Gibson County Coal, LLC operates Gibson, an underground mining complex located near the city of Princeton in Gibson County, Indiana. The mine began production in November 2000. Our Gibson complex utilizes continuous mining units employing room-and-pillar mining techniques. In 2004, Gibson increased mining capacity with the addition of one continuous mining unit. The preparation plant has a throughput capacity of 700 tons of raw coal an hour. We refer to the reserves mined at this location as the Gibson "North" reserves. We also control undeveloped reserves in Gibson County, which are not contiguous to the reserves currently being mined. We refer to these as the Gibson "South" reserves.

Production from Gibson is a low-sulfur coal, that historically has been primarily shipped via truck approximately 10 miles on U.S. and state highways to Gibson's principal customer, PSI Energy Inc. (PSI), a subsidiary of Cinergy Corporation. Gibson's production is also trucked to our Mt. Vernon transloading facility for sale to utilities capable of receiving barge deliveries.

In January 2005, Gibson entered into long-term agreements with PC Indiana Synthetic Fuel #2, L.L.C. (PCIN) to host its coal synfuel facility, supply the facility with coal feedstock, assist PCIN with the marketing of coal synfuel and provide other services. The synfuel facility is expected to commence operations at Gibson in May 2005. At that time, we expect that the majority of Gibson's production will be sold to PCIN. The agreements expire on December 31, 2007 and provide us with coal sales, rental and service fees from PCIN based on the synfuel facility throughput tonnages. These amounts are dependent on the ability of PCIN's members to use certain qualifying tax credits applicable to the facility. 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, revenues associated with the coal synfuel production facility cannot be assured. However, we have entered into "back up" coal supply agreements with each coal synfuel customer that automatically provide for sale of our coal to these customers in the event they do not purchase coal synfuel from PCIN.

For 2005, the incremental annual net income benefit from the combination of the various coal synfuel related agreements associated with the facility being relocated to Gibson is estimated to be $3.3 million, assuming that coal pricing would not increase without the availability of synfuel. This estimated incremental net income cannot be assured. Pursuant to our agreement with PCIN, we are not obligated to make retroactive adjustments or reimbursements if PCIN's tax credits are disallowed.

We have initiated the permitting process for the Gibson South reserves and are actively evaluating its development. Capital expenditures required to develop the Gibson South reserves are estimated to be approximately $80 million. Assuming sufficient sales commitments are obtained and the permitting process progresses as anticipated, initial production could commence in the 2008 to 2009 time frame, with anticipated annual production of 3.2 million tons. Definitive development commitment for Gibson South is dependent upon final approval by the board of directors of our managing general partner.

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 500 employees and operate two mining complexes in East Kentucky.

Pontiki Complex. Pontiki Coal, LLC owns Pontiki, an underground mining complex located near the city of Inez in Martin County, Kentucky. We constructed the mine in 1977. Pontiki owns the mining complex and leases the reserves, and Excel Mining, LLC (Excel), an affiliate of Pontiki, is responsible for conducting all mining operations. Substantially all of the coal produced at Pontiki in 2004 met or exceeded 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. In February 2005 construction efforts began that will allow Pontiki to migrate its mining units into a new coal seam. The first mining unit is expected to move into the new coal seam during the third quarter of 2005. Beginning in 2006, production will still be low sulfur, but may no longer meet the compliance requirements of Phase II Clean Air Act.

Our primary customer for the low-sulfur coal produced at Pontiki is ICG, LLC, the successor-in-interest of certain assets of Horizon Natural Resources Company. We are in a contract dispute in which ICG is alleging we failed to deliver 138,111 tons of coal. Please read "Item 13. Legal Proceedings" and "Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies." Production from the mine is shipped primarily to electric utilities located in the southeastern United States via the Norfolk Southern railroad or by truck via U.S. and state highways to various docks on the Big Sandy River in Kentucky.

MC Mining Complex. MC Mining, LLC owns MC Mining, an underground mining complex located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. MC Mining owns the mining complex and leases the reserves, and Excel, an affiliate of MC Mining, is responsible for conducting all mining operations. Substantially all of the coal produced at MC Mining in 2004 met or exceeded the compliance requirements of Phase II of the Clean Air Act amendments. The complex 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.

On December 26, 2004, MC Mining was temporarily idled following the occurrence of a mine fire. For more information about the MC Mining Fire Incident, please see "Recent Development – MC Mining Mine Fire" above.

Maryland Operations. Our Maryland mining operation is located in the Northern Appalachia coal fields. We have approximately 220 employees and operate one mining complex in Maryland.

Mettiki Complex. Mettiki Coal, LLC operates Mettiki, an underground longwall mining complex located near the city of Oakland 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 pre-paration plant has a throughput capacity of 1,350 tons of raw coal an hour. In response to strong market demand, Mettiki's production capacity was increased through two small-scale third party mining operations.

Historically, our primary customer for the medium-sulfur coal produced at Mettiki has been Virginia Electric and Power Company (VEPCO), which purchased the coal pursuant to a long-term contract for use in the scrubbed 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.

In January 2005, Mettiki entered into what may be the first of a series of short-term purchase orders with Mt. Storm Coal Supply, LLC (Mt. Storm Coal Supply) to supply its coal synfuel facility, located at the Mt. Storm power plant, with coal feedstock. Going forward, the short-term coal feedstock purchase orders are expected to have a term of three months. The incremental quarterly net income benefit from the coal feedstock agreements is estimated to be $0.4 million. The continuation of the short-term agreements cannot be assured. We have entered into a "back up" coal supply agreement with VEPCO for sale of our coal in the event VEPCO does not purchase coal synfuel from Mt. Storm Coal Supply. Pursuant to our agreement with Mt. Storm Coal Supply, we are not obligated to make retroactive adjustments or reimbursements if Mt. Storm Coal Supply's tax credits are disallowed.

Mettiki Coal (WV). Mettiki Coal (WV), LLC has a proposed underground mine to be located primarily in Tucker County, West Virginia, which will eventually replace Mettiki Coal's existing long-wall mine located in Garret County, Maryland. The proposed mine, which will be either a long-wall or continuous mining operation, is approximately 10 miles from Mettiki Coal with coal reserves of approximately 23.3 million tons. Total development capital expenditures are estimated to be $29.9 million, of which $4.9 million has been approved, with the balance subject to approval by the board of directors of our managing general partner. Please see "Regulation and Laws; Mining Permits and Approvals" below concerning the status of Mettiki Coal (WV) permit application for this new mine.

Other Operations

Mt. Vernon Transfer Terminal, LLC . The Mt. Vernon transfer terminal is a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Coal is delivered to Mt. Vernon by both rail and truck. The terminal has a capacity of 8 million tons per year with existing ground storage. During 2004, the terminal loaded approximately 1.8 million tons for Pattiki, Dotiki, and Gibson customers and for third-party shippers.

Coal Brokerage. As markets allow, we buy coal from outside producers principally throughout the eastern United States, which we then resell, both directly and indirectly, primarily to utility customers.We purchased and sold approximately 21,000 tons of outside coal from non-affiliates in 2004. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal. Purchased coal that is delivered to our operations and commingled with our production is not classified as brokerage coal.

Additional Services. We develop and market additional services in order to establish ourselves as the supplier of choice for our customers. Examples of the kind of services we have offered to date include ash and scrubber sludge removal, coal yard maintenance and arranging alternate transportation services. Revenues from these services represented less than one percent of our total revenues.

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 by contributing to both our customers' and our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2004, approximately 92% and 85% of our sales tonnage and total coal sales, respectively, were sold under long-term contracts (contracts having a term of greater than one year) with maturities ranging from 2004 to 2023. Our total nominal commitment under significant long-term contracts was approximately 98.6 million tons at December 31, 2004, and is expected to be delivered as follows: 21.9 million tons in 2005, 20.6 million tons in 2006, 13.0 million tons in 2007, 7.0 million tons in 2008, 6.9 million tons in 2009, and 29.2 million tons thereafter during the remaining terms of the relevant coal supply agreements. The total commitment of coal under contract is an approximate number because, in some instances, our contracts contain provisions that could cause the nominal total commitment to increase or decrease by as much as 20%. The contractual time commitments for customers to nominate future purchase volumes under these contracts are sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal total commitment can otherwise change because of price reopener provisions contained in certain of these long-term contracts.

The terms of long-term contracts are the results of both bidding procedures and extensive negotiations with each 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 two largest customers in 2004 were SSO and VEPCO. Sales to these customers in the aggregate accounted for approximately 33% of our 2004 total revenues, and sales to each of these customers accounted for 10% or more of our 2004 total revenues.

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 20% of the total 2004 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 8% to 43% 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.

Our 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 2004, the largest volume transporter of our coal shipments, including coal synfuel shipped by SSO, was the CSX railroad, which moved approximately 49% 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 Gibson and Mettiki, independent contractors operate truck delivery systems that transport the coal to Gibson and Mettiki's primary customer's power plants.

Regulation and Laws

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

— employee health and safety;
— mine permits and other licensing requirements;
— air quality standards;
— water quality standards;
— storage of petroleum products and substances which are regarded as hazardous under applicable laws or which, if spilled, could reach waterways or wetlands;
— plant and wildlife protection;
— reclamation and restoration of mining properties after mining is completed;
— the discharge of materials into the environment;
— management of solid wastes generated by mining operations;
— storage and handling of explosives;
— wetlands protection;
— 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 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 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 closings, including the cost of treating mine water discharge, when necessary. The accruals for reclamation and mine closing costs are 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 or prevent commencement or continuation of mining operations in certain locations. 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 terminations of operations, the extent of any of which cannot be predicted.

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 like other coal companies we have been cited for violations in the ordinary course of our business, we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

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. Generally, we have not experienced material or significant difficulties in obtaining mining permits in the areas where our reserves are currently located. However, the permitting process for certain mining operations has extended over several years and we cannot assure you that we will not experience difficulty in obtaining mining permits in the future.

Our subsidiary, Mettiki Coal (WV), LLC has a proposed underground mine extension (the E-Mine) to be located primarily in Tucker County, West Virginia, which will eventually replace Mettiki Coal's existing long-wall in (the D-Mine) located in Garrett County, Maryland. The proposed mine, which will be either a long-wall or continuous mining operation, is approximately 10 miles from Mettiki Coal. In order to proceed with the development of the E-Mine, Mettiki Coal (WV) filed two separate permit applications with the West Virginia Department of Environmental Protection (WVDEP) concerning on-site disposal of scalp rock and underground mining, each requiring an associated water discharge permit. We were notified on April 16, May 13, May 26, and June 7, 2004, that WVDEP has issued the permits for on-site disposal of scalp rock, underground mining, water discharge related to the operation of the scalp rock disposal facility, and water discharge related to the operation of the underground mine, respectively.

The appeal periods for the scalp rock permit and the two water discharge permits related to the operation of the scalp rock disposal facility and underground mine have lapsed without any appeal being filed. Two appeals of the underground mining permit were filed on June 11 and 16, 2004, respectively. The West Virginia Surface Mine Board (SMB) consolidated the appeals and held administrative hearings on October 19 and 20, 2004, December 7 and 8, 2004, and January 11 and February 7, 2005.

On March 8, 2005, the SMB issued a Final Order concluding consideration of the consolidated appeals without a decision, which Final Order held that the SMB was unable to take any action relating to the issuance of the underground permit by WVDEP because its vote did not obtain the concurrence of at least four SMB members as required by West Virginia law. Consequently, the ultimate decision by the WVDEP to issue the underground permit was affirmed by operation of West Virginia law. In the Final Order, however, the SMB voted unanimously to require Mettiki Coal (WV) to increase the amount of a surety bond that serves as security for a portion of the reclamation plan approved by WVDEP as part of the underground permit. On March 8, 2005, Mettiki Coal (WV) filed an appeal of the Final Order with the Circuit Court of Tucker County, West Virginia, on the ground that the SMB was wrong in ordering Mettiki Coal (WV) to increase the surety bond for part of the reclamation plan approved by WVDEP when the SMB, as a result of not obtaining the concurrence of at least four members, failed to affirm the decision by WVDEP to issue a final order approving the underground permit issued by WVDEP on May 13, 2004. On March 10, 2005 the West Virginia Rivers Coalition, the West Virginia Highlands Conservancy, and Trout Unlimited – West Virginia Council filed an appeal of the SMB's final order with the Circuit Court of Kanawha County, West Virginia. The appeal requests that the Circuit Court (a) grant a stay of the WVDEP's approval of the E-Mine permit pending a decision by the Circuit Court, (b) set a briefing schedule and oral argument of the appeal and (c) reverse and vacate the WVDEP's approval of the permit. We believe the WVDEP's approval of the permit application will be ultimately upheld by the applicable Circuit Court in West Virginia.

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. The Federal Mine Safety and Health Act of 1977, and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards and imposed comprehensive safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. The Mine Safety and Health Administration (MSHA) 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, regulations governing exposures to diesel particulate matter in underground mines have recently increased our compliance costs, and new regulations that would effectively further limit coal dust and silica exposures are under consideration by MSHA. 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 the 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 issued revised regulations effective January 2001 altering 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 when a miner who is eligible for black lung benefits receives medical treatment for any pulmonary condition, the disorder is caused or aggravated by the miner's work; and
— expand the definition of pneumoconiosis and total disability.

The revised regulations are expected to result in an increase in the incidence and recovery of black lung claims. The amount of the increase in the incidence and recovery of black lung claims will be determined by the future application of the revised regulations in the numerous administrative and judicial processes involved in the adjudication of black lung claims. Concerning our requirement to maintain bonds to secure our black lung claim obligations, see the discussion of surety bonds below under Surface Mining Control and Reclamation Act (SMCRA). 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. We self-insure the potential cost using actuarially determined estimates of the cost of present and future claims. Concerning our requirement to maintain bonds to secure our workers' compensation obligations, see the discussion of surety bonds below under Surface Mining Control and Reclamation Act (SMCRA).

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. However, in connection with the sale of the coal assets acquired by Alliance Resource Holdings in 1996, MAPCO Inc., now a wholly-owned subsidiary of The Williams Companies, Inc., agreed to retain, and be responsible for, all liabilities under CIRHBA.

Surface Mining Control and Reclamation Act (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 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 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 to certain structures occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. The Federal Office of Surface Mining Reclamation and Enforcement is currently studying the adequacy of bonding requirements for treatment of long-term pollution discharges and whether other forms of financial assurances may be permitted. 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 AMD control on a state-wide basis, as West Virginia did in 2002.

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.

In 2002, a U.S. District Court reached a decision interpreting SMCRA to prohibit subsidence from underground mining on certain federal lands, near occupied dwelling, public or community building, public road, schools, churches, and cemeteries, or adversely affecting public parks or certain historic properties. The U.S. Court of Appeals, District of Columbia Circuit, reversed the district court decision as erroneous and in February 2004, the U.S. Supreme Court refused to hear an appeal of the Court of Appeals decision.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers’ compensation, to pay certain black lung claims, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors generally to secure new surety bonds without the posting of partial collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. Surety bonds issuers and holders may not continue to renew bonds or may demand additional collateral upon those renewals. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on us.

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_2) emissions from electric power generation plants in two phases. Only some facilities were subject to the Phase I requirements. Beginning in 2000, Phase II requires nearly all facilities to reduce emissions. The affected 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_2. In addition, the CAA required a study of utility power plant emissions of some toxic substances and their eventual regulation, if warranted. As a result of that study, EPA has proposed, but not yet finalized, alternative regulatory approaches to controlling mercury emissions from power plants. We cannot accurately predict the effect of such CAA controls on us in future years.

The CAA also indirectly affects coal mining operations by requiring utilities that currently are major sources of nitrogen oxides (NOx) in moderate or higher ozone non-attainment areas to install reasonably available control technology for NOx, 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 NOx emissions by 2003. 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 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. Non-attainment designations for these NAAQS were made on December 17, 2004. 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. In conjunction with the mercury proposal noted above, EPA has also proposed an Interstate Air Quality Rule which would require coal-burning power plants in 29 eastern states and the District of Columbia to achieve greater reductions in NOx and SO_2 emissions by means of a "cap and trade" program. Congress may consider other controls on other air pollutants emitted by electric utilities. 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 non-attainment regulations. The issue raised in this litigation is what activities constitute routine maintenance, repair and replacement versus new construction. Some of our customers have agreed to or proposed settlements with EPA while others are preparing for or are engaged in 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.

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

In 2002, the United States withdrew its support for the Kyoto Protocol. As the Kyoto Protocol becomes effective, there will likely be increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. In the last year, the United States Congress has considered bills that would regulate domestic carbon dioxide emissions, but such bills have not yet received sufficient Congressional approvals. Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities.

While higher prices for natural gas and oil, and improved efficiencies and new technologies for coal-fired electric power generation have helped to increase demand for our coal, it is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could have a material adverse effect on our business, financial condition and results of operations.

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. Section 404 of CWA imposes permitting and mitigation requirements associated with the dredging and filling of wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary wetlands permits required under CWA §404. However, mitigation requirements under existing and possible future wetlands permits may vary considerably. 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.

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 polllutants 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 of our operations. These and other regulatory developments may restrict our ability to develop new mines, or could require our customers or us to modify existing operations, the extent of which we cannot accurately or reasonably predict.

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 permits 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, it is unlikely that any of our reclamation activities would fall within the definition of a "public water system." While we have several drinking water supply sources for our employees and contractors that are subject to SDWA regulation, the SDWA is unlikely to have a material impact on our operations.

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

Resource Conservation and Recovery Act (RCRA). The Federal RCRA and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, 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 waste regulatory controls on the disposal of some coal combustion by-products, including the practice of using coal combustion by-products (CCB) as mine fill. However, under pressure from environmental groups, EPA has continued evaluating the possibility of placing additional solid waste burdens on the disposal of these types of materials, and Congress has commissioned a National Academy of Sciences study of CCB mine filling to be concluded by December 2005. EPA's current semi-annual regulatory agent states that a rule on CCB mine filling is planned for proposal in April 2006.

While we cannot predict the ultimate outcome of the National Academy's study or EPA's assessment, we believe the beneficial uses of coal combustion by-products that we employ (such as the practice of placing by-products in abandoned mine areas) do not constitute poor environmental practices because, among other things, our CWA discharge permits for treated AMD contain parameters for pollutants of concern, such as metals, and those permits require monitoring and reporting of effluent quality data.

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.

Also, the Safe Explosives Act (SEA), a portion of the Homeland Security Act of 2002, became law on November 25, 2002. The SEA covers all importers, manufacturers, dealers, and users of explosives. As regular users of explosives, mining companies are likely to be under special scrutiny in its enforcement. Knowing or willful violations of SEA may result in fines, imprisonment, or both. In addition, violations of SEA may result in revocation of user permits and seizure or forfeiture of explosive materials. The SEA became effective in two phases on January 24 and May 24, 2003.

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

Employees

To conduct our operations, our managing general partner and its affiliates employ approximately 2,020 employees, including approximately 100 corporate employees and approximately 1,920 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 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, except for the E-mine permit discussed above in "Item 1. Business; Regulations and Laws; Mining Permits and Approvals", 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 we believe can be economically and legally extracted and produced at the time of the filing of this Annual Report on Form 10-K and are in accordance with guidance from SEC Industry Guide No. 7. In determining whether our reserves meet this economical and legal standard, we take into account, among other things, our potential ability or inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices.

At December 31, 2004, we had approximately 442.4 million tons of coal reserves. All of the estimates of reserves which are presented in this Annual Report on Form 10-K are of proven and probable reserves (as defined below). For information on location of our mines, please read "Mining Operations" under "Item 1. Business."

The following table sets forth reserve information, at December 31, 2004, about each of our mining complexes:

			Proven and Probable Reserves					
		Heat Content	Pounds S02 per MMbtu				Reserve Assignment	
Operations	Mine Type	(Btus per pound)	<1.2	1.2-2.5	>2.5	Total	Assigned	Unassigned
			(tons in millions)					
Illinois Basin Operations								
Dotiki	Underground	12,500	–	–	95.9	95.9	95.9	–
Warrior	Underground	12,500	–	–	22.5	22.5	22.5	–
Pattiki	Underground	11,700	–	–	46.3	46.3	46.3	–
Hopkins	Underground	11,300	–	–	53.1	53.1	33.1	20.0
	/ Surface		–	–	8.4	8.4	8.4	–
Gibson (North)	Underground	11,600	–	36.3	6.3	42.6	42.6	–
Gibson (South)	Underground	11,600	–	46.5	36.2	82.7	–	82.7
Region Total			0.0	82.8	268.7	351.5	248.8	102.7
East Kentucky Operations								
Pontiki	Underground	12,800	9.0	12.2	–	21.2	21.2	–
MC Mining	Underground	12,800	23.6	–	–	23.6	23.6	–
Region Total			32.6	12.2	0.0	44.8	44.8	0.0
Maryland Operations								
Mettiki	Underground	12,200	–	16.5	6.3	22.8	22.8	–
Mettiki Coal (WV)	Underground	12,200	–	–	23.3	23.3	23.3	–
Region Total			0.0	16.5	29.6	46.1	46.1	–
Total			32.6	111.5	298.3	442.4	339.7	102.7
% of Total			7.4 %	25.2 %	67.4 %	100.0 %	76.8 %	23.2 %

The Elk Creek reserves are reported as Hopkins County's assigned underground reserves of 33.2 million tons in the above table. In January 2005, we acquired Tunnel Ridge, LLC that controls 70.0 million tons in the Pittsburgh seam in West Virginia and Pennsylvania, which tonnage figure is not reflected in the above table.

Our reserve estimates are prepared from geological data assembled and analyzed by our staff of geologists and engineers. This data is obtained through our extensive, ongoing exploration drilling and in-mine channel sampling programs. Our drill spacing criteria adhere to standards as defined by the U.S. Geological Survey. The maximum acceptable distance from seam data points varies with the geologic nature of the coal seam being studied, but generally the standard for (a) proven reserves is that points of observation are no greater than 1/2 mile apart and are projected to extend as a 1/4 mile wide belt around each point of measurement and (b) probable reserves is that points of observation are between 1/2 and 1-1/2 miles apart and are projected to extend as a 1/2 mile wide belt that lies 1/4 mile from the points of measurement.

Reserve estimates will change from time to time to reflect evolving market conditions, mining activities,additional analyses, 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 peformed an overview audit of all of our reserves at 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 reflect estimated losses involved in producing a saleable product. All of our reserves are steam coal. The 32.6 million tons of reserves listed as <1.2 pounds of SO_2 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 relating to 23.3 million tons of reserves controlled by Mettiki Coal (WV) has been approved by the WVDEP. However, the permit is subject to appeal. Please see "Item 1. Business; Regulation and Laws; Mining Permits and Approvals" above.

We control certain leases for coal deposits that are near, but not contiguous to, our primary reserve bases. The tons controlled by these leases are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits are as follows: Dotiki – 15.7 million tons, Pattiki – 3.7 million tons, Gibson (North) – 0.9 million tons, Gibson (South) – 7.5 million tons, and Warrior – 2.1 million tons.

We lease almost all of our reserves and generally have the right to maintain leases 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 2004	2003	2002	Transportation	Equipment
	(tons in millions)				
Illinois Basin Operations					
Dotiki	4.8	4.9	4.5	CSX, PAL; truck; barge	CM
Warrior	3.1	2.4	1.6	CSX, PAL; truck	CM
Pattiki	2.5	1.8	1.9	CSX; barge	CM
Hopkins	0.2	0.8	2.2	CSX, PAL; truck	DL; CM
Gibson (North)	3.0	2.4	1.9	Truck; barge	CM
Region Total	13.6	12.3	12.1		
East Kentucky Operations					
Pontiki	1.7	2.0	1.7	NS; truck	CM
MC Mining	1.9	1.6	1.3	CSX; truck	CM
Region Total	3.6	3.6	3.0		
Maryland Operations					
Mettiki	3.2	3.3	2.9	Truck; CSX	LW; CM; CS
Region Total	3.2	3.3	2.9		
TOTAL	20.4	19.2	18.0		

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

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 ICG described under "Other" in "Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies," we are not involved in any litigation involving any of 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 that we believe is material to our operations, including under the various environmental protection statutes to which we are subject. The information under "General Litigation" and "Other" under "Item 8. Financial Statements and Supplementary Data. – Note 17. 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, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The common units representing limited partners' interests are listed on the Nasdaq National Market under the symbol "ARLP." The common units began trading on August 20, 1999. On March 10, 2005, the closing market price for the common units was $73.18 per unit. As of March 10, 2005, there were 18,130,440 common units outstanding, which included 6,422,531 common units that converted from subordinated units in November 2003 and 2004. There were approximately 19,400 record holders and beneficial owners (held in street name) of common units at December 31, 2004.

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

	High	Low	Distributions Per Unit
1st Quarter 2003	$25.500	$21.490	$0.5250 (paid May 15, 2003)
2nd Quarter 2003	$27.999	$21.980	$0.5250 (paid August 14, 2003)
3rd Quarter 2003	$29.920	$25.480	$0.5250 (paid November 14, 2003)
4th Quarter 2003	$35.240	$28.000	$0.5625 (paid February 13, 2004)
1st Quarter 2004	$40.910	$30.510	$0.625 (paid May 14, 2004)
2nd Quarter 2004	$47.380	$33.100	$0.650 (paid August 2, 2004)
3rd Quarter 2004	$56.570	$44.120	$0.650 (paid November 12, 2004)
4th Quarter 2004	$74.770	$54.800	$0.750 (paid February 14, 2005)

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

Under the quarterly incentive distribution provisions of the Partnership Agreement, our managing general partner is entitled to receive 15% of the amount we distribute in excess of $0.55 per unit, 25% of the amount we distribute in excess of $0.625 per unit, and 50% of the amount we distribute in excess of $0.75 per unit.

Equity Compensation Plans

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

ITEM 6. SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2004, 2003, 2002, 2001 and 2000. We acquired Warrior from ARH Warrior Holdings, a subsidiary of Alliance Resource Holdings, in February 2003. Because the Warrior acquisition was between entities under common control, it is accounted for at historical cost in a manner similar to that used in a pooling of interests. Accordingly, the financial statements as of December 31, 2002 and 2001, and for each of the two years in the period ended December 31, 2002, have been restated to reflect the combined historical results of operations, financial position, and cash flows of the Partnership and Warrior. ARH Warrior Holdings acquired the assets that comprise Warrior on January 26, 2001.

	Year Ended December 31,				
	2004	2003	2002	2001	2000
(in millions, except per unit and per ton data)					
Statements of Income:					
Sales and operating revenues					
Coal sales	$ 599.4	$ 501.6	$ 479.5	$ 453.1	$ 347.2
Transportation revenues	29.8	19.5	19.0	18.2	13.5
Other sales and operating revenues	24.1	21.6	20.4	6.2	2.8
Total revenues	653.3	542.7	518.9	477.5	363.5
Expenses:					
Operating expenses	436.4	368.8	367.5	337.2	257.4
Transportation expenses	29.8	19.5	19.0	18.2	13.5
Outside purchases	9.9	8.5	10.1	28.9	16.9
General and administrative	45.4	28.3	20.3	18.7	15.2
Depreciation, depletion and amortization	53.7	52.5	52.4	50.7	39.1
Interest expense	15.0	16.0	16.4	16.8	16.6
Unusual items (1)	–	–	–	–	(9.5)
Net gain from insurance settlement (2)	(15.2)	–	–	–	–
Total expenses	575.0	493.6	485.7	470.5	349.2
Income from operations	78.3	49.1	33.2	7.0	14.3
Other income	1.0	1.4	0.5	0.8	1.3
Income before income taxes and cumulative effect of accounting change	79.3	50.5	33.7	7.8	15.6
Income tax expense (benefit)	2.7	2.6	(1.1)	(0.8)	–
Income before cumulative effect of accounting change	76.6	47.9	34.8	8.6	15.6
Cumulative effect of accounting change (3)	–	–	–	7.9	–
Net income	$ 76.6	$ 47.9	$ 34.8	$ 16.5	$ 15.6
General Partners' interest in net income	$ 3.3	$ 0.3	$ (0.8)	$ (0.2)	$ 0.3
Limited Partners' interest in net income	$ 73.3	$ 47.6	$ 35.6	$ 16.7	$ 15.3
Basic net income per limited partner unit	$ 4.09	$ 2.71	$ 2.31	$ 1.09	$ 0.99
Basic net income per limited partner unit before accounting change	$ 4.09	$ 2.71	$ 2.31	$ 0.58	$ 0.99
Diluted net income per limited partner unit	$ 3.98	$ 2.62	$ 2.24	$ 1.07	$ 0.98
Diluted net income per limited partner unit before accounting change	$ 3.98	$ 2.62	$ 2.24	$ 0.57	$ 0.98
Weighted average number of units outstanding-basic	17,940,948	17,580,734	15,405,311	15,405,311	15,405,311
Weighted average number of units outstanding-diluted	18,437,168	18,162,839	15,842,708	15,684,550	15,551,062
Balance Sheet Data:					
Working capital (deficit)	$ 54.2	$ 16.4	$ (15.8)	$ 0.9	$ 38.6
Total assets	412.8	336.5	316.9	310.3	309.2
Long-term debt	162.0	180.0	195.0	211.3	226.3
Total liabilities	357.6	323.9	355.7	347.8	341.0
Partners' capital (deficit)	55.2	12.6	(38.8)	(37.6)	(31.8)
Other Operating Data:					
Tons sold	20.8	19.5	18.4	18.6	15.0
Tons produced	20.4	19.2	18.0	17.4	13.7
Revenues per ton sold (4)	$ 29.98	$ 26.83	$ 27.17	$ 24.69	$ 23.33
Cost per ton sold (5)	$ 23.64	$ 20.80	$ 21.63	$ 20.69	$ 19.30
Other Financial Data:					
Net cash provided by operating activities	$ 145.1	$ 110.3	$ 101.3	$ 70.5	$ 71.4
Net cash used in investing activities	(77.6)	(77.8)	(56.9)	(31.1)	(41.0)
Net cash used in financing activities	(46.4)	(31.3)	(46.4)	(35.2)	(31.4)
EBITDA (6)	148.0	119.0	102.5	83.2	71.3
Maintenance capital expenditures (7)	31.6	30.0	29.0	24.4	21.2

(1) 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.

(2) Represents the net gain from the final settlement with the Partnership's insurance underwriters for claims relating to the Dotiki Mine Fire Incident. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations; Summary" for a description of the accounting treatment of expenses and insurance proceeds associated with the Dotiki Fire Incident.

(3) Represents the cumulative effect of the change in the method of estimating coal workers' pneumoconiosis ("black lung") benefits liability effective January 1, 2001. Please 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 4. Accounting Change."

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

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

(6) EBITDA is defined as net income before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

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

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

The following table presents a reconciliation of the non-GAAP financial measure of EBITDA to the GAAP financial measure of net income (in millions):

	Year Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
Net Income	$ 76.6	$ 47.9	$ 34.8	$16.5	$15.6
Add:					
Depreciation, depletion and amortization	53.7	52.5	52.4	50.7	39.1
Interest expense	15.0	16.0	16.4	16.8	16.6
Income tax expense (benefit)	2.7	2.6	(1.1)	(0.8)	–
EBITDA	$148.0	$119.0	$102.5	$83.2	$71.3

(7) Our maintenance capital expenditures, as defined under the terms of our partnership agreement, are those capital expenditures required to maintain, over the long-term, the operating capacity of our capital assets. Maintenance capital expenditures for our predecessor reflect our historical designation of maintenance capital expenditures. Maintenance capital expenditures for the years ended December 31, 2002 and 2001 have not been restated to include Warrior.

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 operation should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this Annual Report on Form 10-K. We acquired Warrior from ARH Warrior Holdings, a subsidiary of Alliance Resource Holdings, in February 2003. Because the Warrior acquisition was between entities under common control, it is accounted for at historical cost in a manner similar to that used in a pooling of interests. Accordingly, the financial statements as of December 31, 2002 and 2001, and for each of the two years in the period ended December 31, 2002, have beenrestated to reflect the combined historical results of operations, financial position and cash flows of the Partnership and Warrior. ARH Warrior Holdings acquired Warrior on January 26, 2001. For more detailed information regarding the basis of presentation for the following financial information, please see "Item 8. Financial Statements and Supplementary Data. - Note 1. Organization and Presentation and Note 2. Summary of Significant Accounting Policies."

Business

We are a diversified producer and marketer of coal to major U.S. utilities and industrial users. In 2004, our total production was 20.4 million tons and our total sales were 20.8 million tons. The coal we produced in 2004 was approximately 32.3% low-sulfur coal, 15.7% medium-sulfur coal and 52.0% high-sulfur coal.

At December 31, 2004, we had approximately 442.4 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 properties adjacent to some of our Illinois Basin region operations that we currently intend to acquire or lease as our mining operations approach these areas.

In 2004, approximately 79% of our sales tonnage was consumed by electric utilities with the balance consumed by cogeneration plants and industrial users. Our largest customers in 2004 were SSO and VEPCO. In 2004, approximately 92% of our sales tonnage, including approximately 94% of our medium- and high-sulfur coal sales tonnage, was sold under long-term contracts. The balance of our sales was made in the spot market. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2004, approximately 88% 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 have entered into long-term agreements with SSO to host and operate its coal synfuel production facility currently located at Warrior, supply the facility with coal feedstock, assist SSO with the marketing of coal synfuel and provide it with other services. These agreements expire on December 31, 2007 and provide us with coal sales and rental and service fees from SSO based on the synfuel facility throughput tonnages. These amounts are dependent on the ability of SSO's members to use certain qualifying tax credits applicable to the facility. The term of each of these agreements 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. We have maintained "back up" coal supply agreements with each coal synfuel customer that automatically provide for sale of our coal to these customers in the event they do not purchase coal synfuel from SSO. In conjunction with a decision to relocate the coal synfuel production facility from Hopkins to Warrior, agreements for providing certain of these services were assigned to Alliance Service, a wholly-owned subsidiary of Alliance Coal, in December 2002. Alliance Service is subject to federal and state income taxes.

For 2004, the incremental annual net income benefit from the combination of the various coal synfuel-related agreements was approximately $16.9 million, assuming that coal pricing would not have increased without the availability of synfuel. The continuation of the incremental net income benefit associated with SSO's coal synfuel facility cannot be assured. We earn income by supplying SSO's synfuel facility with coal feedstock, assisting SSO with the marketing of coal synfuel, and providing rental and other services. Pursuant to our agreement with SSO, we are not obligated to make retroactive adjustments or reimbursements if SSO's tax credits are disallowed.

In June 2003, the IRS suspended the issuance of private letter rulings on the significant chemical change requirement to qualify for synfuel tax credits and announced that it was reviewing the test procedures and results used by taxpayers to establish that a significant chemical change had occurred. In October 2003, the IRS completed its review and concluded that the test procedures and results were scientifically valid if applied in a consistent and unbiased manner. The IRS has resumed issuing private letter rulings under its existing guidelines. SSO has advised us that its private letter ruling could be reviewed by the IRS as part of a tax audit, similar to the IRS reviews of other synfuel procedures. SSO has also advised us that the Permanent Subcommittee on Investigations of the Senate Committee on Governmental Affairs (Subcommittee) is reviewing the synfuel industry, that the Subcommittee has indicated that they hope to interview almost all taxpayers that are involved in the synfuel business, and that SSO has been requested to meet informally with the Subcommittee to help enhance the Subcommittee's knowledge of the synfuel industry.

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.

Summary. In 2004, we reported record net income of $76.6 million, an increase of 60% over 2003 net income of $47.9 million. We grew through expansion of production capacity at Gibson, Dotiki and Pattiki, resumption of operations at the surface mine at Hopkins County Coal, and the addition of two third-party mining operations at our Mettiki operation. Tons produced increased 5.9% to 20.4 million tons. Tons sold increased 7.0% to 20.8 million tons.

During 2004, we benefited from strong coal markets as revenues rose to record levels and average coal sales prices in 2004 increased 11.7% compared to 2003.

We have commitments for substantially all of our 2005 production. For our estimated 2006 production, approximately 84% is committed under existing coal sales agreements and approximately 36% of the committed tonnage is subject to market price negotiations.

On December 26, 2004 the MC Mining Excel No. 3 mine was temporarily idled following the occurrence of a mine fire. The fire was discovered by mine personnel near the bottom of the Excel No. 3 mine slope late the evening of December 25, 2004. Under a firefighting plan developed by MC Mining, in cooperation with mine emergency response teams from the Mine Safety and Health Administration and Kentucky Office of Mine Safety and Licensing , the four portals at the Excel No. 3 mine were capped to deprive the fire of oxygen. A series of boreholes were then drilled into the fire area to further suppress the fire. As a result of these efforts, the mine atmosphere was rendered substantially inert, or without oxygen, and the Excel No. 3 mine fire was effectively suppressed. MC Mining then began construction of temporary and permanent barriers designed to completely isolate the mine fire area. When construction of the permanent barriers was completed, MC Mining began efforts to repair and rehabilitate the Excel No. 3 mine infrastructure. On February 21, 2005, the repair and rehabilitation efforts had progressed sufficiently to allow initial resumption of production. We anticipate that MC Mining may return to full production by the end of the first quarter of 2005, but we cannot assure that our ability to produce will not continue to be adversely impacted by the MC Mining Fire Incident for a period of time. The boreholes continue to be used to monitor the mine atmosphere and to inject nitrogen into the area of the fire now isolated behind the permanent barriers.

We maintain commercial property (including business interruption) insurance policies, which are renewed annually in September and provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles, (collectively the 2005 Deductibles) and 10% co-insurance (2005 Co-Insurance), but we cannot give any assurances as to the eventual timing or amount of any recovery of proceeds under these policies. We have made initial estimates of certain costs primarily associated with activities relating to the suppression of the fire and the resumption of operations. Operating expenses for the 2004 fourth quarter increased by $4.1 million reflecting an initial estimate of certain minimum costs attributable to the MC Mining Fire Incident that are not reimbursable under our insurance policies due to the application of the 2005 Deductibles and 2005 Co-Insurance. An increase in the amount of such costs is possible, but is not currently subject to a reasonable estimate at this time. In addition to these initial cost estimates, we expect to incur additional out-of-pocket costs that will generally fall into the categories of extra expenses, expediting expenses and other areas of coverage under the commercial insurance policies. These future out-of-pocket costs, which are not currently subject to reasonable estimation, will be expensed as incurred. The related estimated insurance recovery of these costs will be recorded, net of 2005 Deductibles and 2005 Co-Insurance, as we determine that such recoveries are probable. Any recovery under the insurance policies of business interruption proceeds attributable to amounts in excess of actual costs incurred will be recorded as gains when the claims are settled with the insurance underwriters.

On February 11, 2004, Webster County Coal's Dotiki mine was temporarily idled for a period of twenty-seven calendar days following the occurrence of a mine fire that originated with a diesel supply tractor. As a result of the firefighting efforts of the Mine Safety and Health Administration, Kentucky Department of Mines and Minerals, and Webster County Coal personnel, Dotiki successfully extinguished the fire and totally isolated the affected area of the mine behind permanent barriers. Initial production resumed on March 8, 2004. For the Dotiki Fire Incident, we had commercial property insurance that provided coverage for damage to property destroyed, interruption of business operations, including profit recovery, and expenditures incurred to minimize the period and total cost of disruption to operations.

On September 10, 2004, we filed a third and final proof of loss with the applicable insurance underwriters reflecting a settlement (the Dotiki Settlement) of all expenses, losses and claims incurred by Webster County Coal and other affiliates arising from or in connection with the Dotiki Fire Incident (the Dotiki Insurance Claim) in the aggregate amount of $27.0 million, inclusive of a $1.0 million self-retention, a $2.5 million deductible (collectively, the 2004 Insurance Deductibles) and 10% Co-Insurance (the 2004 Co-Insurance). The 2004 Insurance Deductibles and 2004 Co-Insurance were allocated on a pro-rata basis to each of the three areas of insurance recoveries discussed below. In addition, the accounting for two net partial advance payments in the aggregate amount of $8.1 million and the final net payment of $13.05 million, exclusive of the 2004 Insurance Deductible and 2004 Co-Insurance, were subject to the accounting methodology described below. Specifically, we evaluated and accounted for the insurance recoveries in the following areas:

1. Expenses incurred as a result of the fire: We incurred extra expenses, expediting expenses, and other costs associated with extinguishing the fire in an aggregate amount of approximately $7.1 million. With application of $5.6 million of the insurance recovery proceeds, we recorded net expenses of approximately $1.5 million.
2. Damage to Dotiki mine property: We incurred damage to Dotiki's mine property (exclusive of any amounts relating to matters discussed in 1. above) of approximately $1.2 million, which property had a net book value of $138,000. Based on discussions with the underwriters culminating in the Dotiki Settlement, we recorded a net gain of approximately $785,000, reflecting the amount that the allocated insurance proceeds exceeded the net book value of the damaged property.
3. Dotiki mine business interruption costs and extra expense: Based on the negotiations with the underwriters leading to the Dotiki Settlement, we recorded a net gain of approximately $14.4 million for the recovery of business interruption costs and extra expenses stemming from the Dotiki Fire Incident. This net gain amount reflects an offset of approximately $200,000 for professional services expenses incurred in resolving the business interruption portion of the Dotiki Settlement.

Pursuant to the accounting methodology described above, in 2004 we recorded (a) an offset to operating expenses of approximately $5.9 million and (b) a combined net gain of approximately $15.2 million for damage to property destroyed, interruption of business operations (including profit recovery), and extra expenses incurred to minimize the period and total cost of disruption to operations associated with the Dotiki Fire Incident.

Results of Operations

2004 Compared with 2003

	2004	2003	Per Ton Sold 2004	Per Ton Sold 2003
	(in thousands)			
Tons sold	20,823	19,467	N/A	N/A
Tons produced	20,377	19,238	N/A	N/A
Coal Sales	$599,399	$501,596	$ 28.79	$ 25.77
Operating Expenses and Outside Purchases	$446,384	$377,343	$ 21.44	$ 19.38

Coal sales. Coal sales increased 19.5% to $599.4 million for 2004 from $501.6 million for 2003. The increase of $97.8 million reflects higher prices on long-term coal sales agreements and the sale of additional production at significantly higher prices on short-term coal sales agreements into the export and Central Appalachia coal markets. Higher prices on long-term contracts reflect a stronger market in the second half of 2003 when contracts were entered into for shipments in 2004. The export market opportunities for the U.S. coal industry were attributable generally to the strong economic expansion in China. The increase in Central Appalachia spot market pricing was attributable primarily to a combination of the diversion of coal production from domestic markets to export markets and a decline in region-wide production. Tons sold increased 7.0% to 20.8 million for 2004 from 19.5 million in 2003, primarily reflecting an increase in tons produced. Tons produced increased 5.9% to 20.4 million for 2004 from 19.2 million in 2003.

Operating expenses. Operating expenses increased 18.3% to $436.5 million in 2004 from $368.8 million in 2003. The increase of $67.7 million was primarily attributable to (a) additional sales of 1.4 million tons, (b) higher maintenance expense and materials and supplies costs (particularly fuel, power and steel), (c) adverse geologic conditions at the Pontiki mine, (d) increased longwall moves associated with shorter longwall panels at the Mettiki mine and (e) additional costs associated with the MC Mining and Dotiki Fire Incidents described above. Operating expenses include an accrual of $4.1 million reflecting our initial estimate of the minimum non-reimbursable costs attributable to the MC Mining Fire Incident. Additionally, 2004 includes a $3.5 million buy-out expense of several coal contracts which will allow us to take advantage of anticipated higher spot coal prices in 2005.

Other sales and operating revenues. Other sales and operating revenues, which are primarily comprised of services to the coal synfuel production facility, increased 11.5% to $24.1 million in 2004 from $21.6 million in 2003. The increase of $2.5 million was primarily attributable to additional rent and service fees associated with increased volumes at a third-party coal synfuel facility at Warrior.

General and administrative. General and administrative expenses for 2004 increased to $45.4 million compared to $28.3 million for 2003. The $17.1 million increase was primarily attributable to higher incentive compensation expense, which increased approximately $16.0 million. The incentive compensation plans include the Long-Term Incentive Plan, a restricted unit plan, and the Supplemental Executive Retirement Plan, a phantom unit plan, both of which are impacted by the increased market value of our common units, which had a closing market price of $74.00 on December 31, 2004 compared to a closing market price of $34.38 on December 31, 2003, and the Short-Term Incentive Plan, which provides our employees an opportunity to receive additional compensation based on our financial performance.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $53.7 million in 2004 compared to $52.5 million in 2003. The increase of $1.2 million was primarily the result of additional depreciation expense associated with increased capital expenditures and infrastructure investments over the last few years, which have increased our production capacity. The increase was partially offset by a $2.6 million decrease in depreciation attributable to operating Hopkins County Coal six months in 2003 compared to three months in 2004.

Interest expense. Interest expense declined 6.4% to $15.0 million in 2004 from $16.0 million in 2003. The decrease of $1.0 million was attributable to reduced interest expense associated with the revolving credit facility. We had no borrowings under the credit facility during 2004.

Outside purchases. Outside purchases increased 16.5% to $9.9 million in 2004 from $8.5 million in 2003. The increase was primarily attributable to an increase in outside purchases associated with our East Kentucky and Illinois Basin operations partially offset by a decrease in the domestic brokerage market.

Transportation revenues and expenses. Transportation revenues and expenses increased 52.5% to $29.8 million in 2004 from $19.6 million for 2003. The increase of $10.3 million was primarily attributable to increased shipments to customers that reimburse us for transportation costs rather than arranging and paying for transportation directly with transportation providers.

Income before income tax expense (benefit). Income before income tax expense (benefit) increased 57.0% to $79.3 million for 2004 compared to $50.5 million for 2003. The increase was primarily attributable to higher sales prices, reflecting the continued strengthening of domestic and international coal markets, partially offset by higher operating expenses and increased general and administrative expense, primarily attributable to higher incentive compensation expense.

Income tax expense (benefit). Income tax expense was comparable for both 2004 and 2003 at $2.6 million for each year.

2003 Compared with 2002

			Per Ton Sold	
	2003	2002	2003	2002
	(in thousands)			
Tons sold	19,467	18,370	N/A	N/A
Tons produced	19,238	17,970	N/A	N/A
Coal Sales	$501,596	$479,515	$ 25.77	$ 26.10
Operating Expenses and Outside Purchases	$377,343	$377,644	$ 19.38	$ 20.56

Coal sales. Coal sales for 2003 increased 4.6% to $501.6 million from $479.5 million for 2002. The increase of $22.1 million was attributable to increased tons sold partially offset by lower sales prices. Sales prices in 2002 benefited from coal sales agreements entered into during the second half of 2001 when sales prices for deliveries in 2002 increased in response to a combination of factors including low coal stockpiles and supply shortages. Tons sold increased 6.0% to 19.5 million for 2003 from 18.4 million in 2002, reflecting an increase in tons produced. Tons produced increased 7.1% to 19.2 million for 2003 from 18.0 million in 2002. Please see "Operating Expenses" below concerning the increase in tons produced.

Operating expenses. Operating expenses were comparable for 2003 and 2002 at $368.8 million and $367.6 million, respectively. Increased operating expenses associated with higher production and sales levels at our active mines were offset by a decrease associated with the idling of the Hopkins complex on June 2, 2003. Operating expenses declined on a cost-per-ton sold basis as production increased at all of our active operations except Pattiki. Pattiki's production was essentially the same in 2003 and 2002.

Increased production reflects the absence of the adverse geologic conditions encountered at Mettiki in the third quarter of 2002 and the emerging benefit of several strategic capital investments made during the past two years. We have added continuous miner units at Gibson, Warrior and MC Mining and have made infrastructure investments, such as new mine shafts, at Dotiki, Warrior and MC Mining. Additionally, operating expenses decreased due to the reversal of an expense accrual of $1.2 million established in 1998. The expense accrual was established in conjunction with the idling of Pontiki in 1998 that created an expectation of a probable increase in workers' compensation costs associated with the terminated workforce. The anticipated increase in workers' compensation claims did not emerge and, with limited exceptions, the statute of limitations expired in December 2003 for the filing or reopening of workers'compensation claims associated with the employee terminations.

Other sales and operating revenues. Other sales and operating revenues, which is primarily comprised of services to the coal synfuel production facility, increased 6.0% to $21.6 million from $20.4 million in 2002. However, the $1.2 million increase was primarily attributable to providing additional services for treating, handling and transporting coal unrelated to the coal synfuel services.

General and administrative. General and administrative expenses for 2003 increased 39.0% to $28.3 million compared to $20.3 million for 2002. The $8.0 million increase was primarily attributable to higher expense accruals of $6.9 million associated with incentive compensation programs, and the remaining increase in expense reflects various other increases in administrative compliance costs.

Depreciation, depletion and amortization. Depreciation, depletion and amortization were comparable for 2003 and 2002 at $52.5 million and $52.4 million, respectively. Additional depreciation associated with the capital additions described in "Operating Expenses" above was offset by lower depreciation of $3.0 million at the idled Hopkins complex. Please see "Item 1. Business, Mining Operations, Illinois Basin Operations."

Interest expense. Interest expense for 2003 declined 2.3% to $16.0 million from $16.4 million in 2002 primarily attributable to decreased borrowings under the revolving credit facility.

Outside purchases. Outside purchases for 2003 decreased 15.6% to $8.5 million from $10.1 million in 2002. The decrease was primarily attributable to a decrease in coal purchases from a third-party producer that ceased production in the fourth quarter of 2002.

Transportation revenues and expenses. Transportation revenues and expenses for 2003 increased 3.0% to 19.6 million from $19.0 million for 2002. The increase of $0.6 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.

Income before income tax expense (benefit) and cumulative effect of accounting change. Income before income tax expense (benefit) and cumulative effect of accounting change increased 49.8% to $50.5 million for 2003 compared to $33.7 million for 2002. The increase was primarily attributable to lower cost per-ton-sold operating costs and higher sales volumes, partially offset by lower sales prices and increased general and administrative expenses.

Income tax expense (benefit). Income tax expense for 2003 was $2.6 million compared to an income tax benefit of $1.1 million in 2002. Although we are not a taxable entity for federal or state income tax purposes, our subsidiary, Alliance Service is subject to federal and state income taxes. In conjunction with a decision to relocate the coal synfuel facility, agreements for a portion of the services provided to the coal synfuel producer were assigned to Alliance Service in December 2002. Approximately $2.1 million of the increase in income tax expense was associated with coal synfuel-related services performed by Alliance Service. The balance of the income tax expense increase was attributable to Warrior, which had a net income tax benefit for the year 2002 of approximately $1.3 million. Since our acquisition of Warrior on February 14, 2003, the financial results of Warrior are no longer subject to federal or state income taxes.

Ongoing Acquisition Activities

Consistent with our business strategy, from time-to-time we engage in discussions with potential sellers regarding possible acquisitions of certain assets and/or companies by us.

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 distribution payments. To further develop available financing alternatives, in October 2002, we entered into a master lease agreement. Under the master lease agreement, lease terms and rental payments are negotiated individually when specific pieces of equipment are leased. During 2004 and 2003, we had rental expense of $1.3 million and $1.0 million, respectively, under the master lease agreement. We had no equipment leased under the master equipment lease at December 31, 2002. Our credit facility limits the amount of total operating lease obligations to $15.0 million payable in any period of 12 consecutive months. 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 $145.1 million in 2004, compared to $110.3 million in 2003. The increase in cash provided by operating activities was principally attributable to an increase in net income and a greater reduction in total working capital.

Net cash used in investing activities was comparable for 2004 and 2003 at $77.6 million and $77.8 million, respectively.

Net cash used in financing activities was $46.4 million for 2004 compared to $31.3 million for 2003. The increase is primarily attributable to the increased distributions to partners in 2004 compared to 2003.

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, capital project commitments, and pension funding. 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, 2004 (in thousands):

Contractual Obligations	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
Long-term debt	$ 180,000	$ 18,000	$ 36,000	$ 36,000	$ 90,000
Operating leases	20,602	4,666	7,659	5,467	2,810
Other long-term obligations (excluding discount effect of $28.8 million for reclamation liability)	62,778	1,180	6,106	822	54,670
Capital projects	8,386	8,386	–	–	–
	$ 271,766	$ 32,232	$ 49,765	$ 42,289	$ 147,480

We expect to contribute $2.7 million to the defined benefit pension plan (Pension Plan) during 2005. We estimate that our interest and income tax cash requirements will be approximately $14.3 million and $2.7 million, respectively in 2005.

Capital Expenditures. Capital expenditures decreased to $54.7 million in 2004 compared to $55.7 million in 2003, which includes the acquisition of Warrior Coal. Excluding the Warrior acquisition, capital expenditures for 2004 increased $11.7 million compared to capital expenditures for the 2003 period. The increase in capital expenditures is associated with Dotiki expanding its preparation plant and adding two continuous miners, and the addition of one continuous mining unit at Gibson and Pattiki.

In February 2003, we acquired Warrior from an affiliate, ARH Warrior Holdings, pursuant to the terms of a previously existing agreement. Warrior owns an underground mining complex located between and adjacent to our other western Kentucky operations near Madisonville, Kentucky. We paid $12.7 million to ARH Warrior Holdings in accordance with the terms of an Amended and Restated Put and Call Option Agreement. In addition, we repaid Warrior's borrowings of $17.0 million under the revolving credit agreement between our special general partner and Warrior. We funded the Warrior acquisition through a portion of the proceeds received from the issuance of 2,250,000 common units in February 2003.

We currently project that our average annual maintenance capital expenditures will be approximately $50.0 million. We also currently expect to fund our anticipated total capital expenditures for 2005 of $79.9 million, with cash generated from operations and borrowings under our revolving credit facility described below.

Notes Offering and Credit Facility. Alliance Resource Operating Partners, L.P., our intermediate partnership, has $180 million principal amount of 8.31% senior notes due August 20, 2014, payable in ten equal annual installments of $18 million beginning in August 2005 with interest payable semi-annually (Senior Notes). On August 22, 2003, our intermediate partnership completed an $85 million revolving credit facility (Credit Facility), which expires September 30, 2006. The Credit Facility replaced a $100 million credit facility that would have expired August 2004. We paid in full all amounts outstanding under the $100 million original credit facility with borrowings of $20 million under the Credit Facility. The interest rate on the Credit Facility is based on either the (i) London Interbank Offered Rate or (ii) the "Base Rate", which is equal to the greater of the JPMorgan Chase Prime Rate or the Federal Funds Rate plus 1/2 of 1%, plus, in either case, an applicable margin. We incurred certain costs aggregating $1.2 million associated with the Credit Facility. These costs have been deferred and are being amortized as a component of interest expense over the term of the Credit Facility. We had no borrowings outstanding under the Credit Facility at December 31, 2004. Letters of credit can be issued under the Credit Facility not to exceed $30 million. Outstanding letters of credit reduce amounts available under the Credit Facility. At December 31, 2004, we had letters of credit of $9.0 million outstanding under the Credit Facility.

The Senior Notes and Credit Facility are guaranteed by all of the subsidiaries of our intermediate partnership. The Senior Notes and Credit Facility contain various restrictive and affirmative covenants, including restrictions on the amount of distributions by our 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, 2004.

We have previously entered into and have maintained agreements with two banks to provide additional letters of credit in an aggregate amount of $25.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2004, we had $22.2 million in letters of credit outstanding under these agreements. Our special general partner guarantees the letters of credit.

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 financial statements. Please 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 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. Events or changes in circumstance that could cause us to perform such a review include, but are not limited to, the loss of a major coal supply agreement, a significant decline in demand for our coal and an adverse change in geologic conditions.

Reclamation and Mine Closing Costs. The Federal SMCRA 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 $34.0 million and $23.5 million for these costs at December 31, 2004 and 2003, respectively. The liability for mine reclamation and closing procedures is sensitive to changes in cost estimates and estimated mine lives.

Workers' Compensation and Pneumoconiosis ("Black Lung") Benefits. We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. We 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 independent actuarial study. 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 $32.6 million and $28.7 million for these costs at December 31, 2004 and 2003, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2004 approximately $1.8 million, which would have a corresponding increase in operating expenses.

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 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 $20.3 million and $17.6 million for these benefits at December 31, 2004 and 2003, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2004 by approximately $0.9 million. Under the service cost method used to estimate our black lung benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions such as the discount rate are amortized over the remaining service period of active miners.

Universal Shelf

In April 2002, we filed with the Securities and Exchange Commission a universal shelf registration statement allowing us to issue from time-to-time up to an aggregate of $200 million of debt or equity securities. At March 1, 2005, we had approximately $142.9 million available under this registration statement.

Related Party Transactions

Administrative Services. Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses they incur or payments they make on our behalf including, but not limited to, management's salaries and related benefits (including incentive compensation), and accounting, budget, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers' compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $28,536,000, $12,471,000, and $6,559,000 for the years ended December 31, 2004, 2003, and 2002, respectively. The increases from 2003 to 2004 and 2002 to 2003 were primarily attributable to higher accruals related to common unit based incentive plans, which were impacted by the increased market value of our common units, and the Short Term Incentive Plan (STIP).

Warrior Acquisition. On February 14, 2003, we acquired Warrior from an affiliate, ARH Warrior Holdings a subsidiary of Alliance Resource Holdings, pursuant to an Amended and Restated Put and Call Option Agreement (Put/Call Agreement). Warrior purchased the capital stock of Roberts Bros. Coal Co., Inc., Warrior Coal Mining Company, Warrior Coal Corporation and certain assets of Christian Coal Corp. and Richland Mining Co., Inc. in January 2001. Our managing general partner had previously declined the opportunity to purchase these assets as we had previously committed to major capital expenditures at two existing operations. As a condition to not exercising its right of first refusal, we requested that ARH Warrior Holdings enter into a put and call arrangement for Warrior. We and ARH Warrior Holdings, with the approval of the conflicts committee of our managing general partner, entered into the Put/Call Agreement in January 2001. Concurrently, ARH Warrior Holdings acquired Warrior in January 2001 for $10.0 million.

The Put/Call Agreement preserved the opportunity for us to acquire Warrior during a specified time period. Under the terms of the Put/Call Agreement, ARH Warrior Holdings exercised its put option requiring us to purchase Warrior at a put option price of approximately $12.7 million.

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

The Put/Call Agreement option prices reflected 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 were exercised. In January 2001 and in December 2002, we developed financial projections for Warrior 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 included, among others, (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below the then current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, as of the date of the acquisition and at December 31, 2002 and 2001, we believe that the fair value of Warrior was equal to or greater than the put option exercise price.

The put option price of $12.7 million was paid to ARH Warrior Holdings in accordance with the terms of the Put/Call Agreement. In addition, we repaid Warrior's borrowings of $17.0 million under the revolving credit agreement between our special general partner and Warrior. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior that have contributed to improved productivity and significantly increased capacity. We funded the Warrior acquisition through a portion of the proceeds received from the issuance of 2,250,000 common units. Because the Warrior acquisition was between entities under common control, it has been accounted for at historical cost in a manner similar to that used in a pooling of interests.

Under the terms of the Put/Call Agreement, we assumed certain other obligations, including a mineral lease and sublease with SGP Land, a subsidiary of our special general partner, covering coal reserves that have been and will continue to be mined by Warrior. The terms and conditions of the mineral lease and sub-lease remain unchanged.

SGP Land. Dotiki has a mineral lease and sublease with SGP Land requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Dotiki paid royalties of $4,611,000, $3,460,000, and $2,700,000 for the years ended December 31, 2004, 2003 and 2002, respectively. Dotiki has recouped as earned royalties all advance minimum royalty payments made under these lease terms except for $805,000 as of December 31, 2004.

Warrior has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior has paid and will continue to pay in arrears an annual minimum royalty obligation of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments have been paid. The annual minimum royalty periods are from October 1st through the end of the following September, expiring September 30, 2007. Warrior paid royalties of $2,561,000, $2,453,000, and $2,127,000 for the years ended December 31, 2004, 2003, and 2002, respectively. Warrior has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $636,000 as of December 31, 2004.

Under the terms of the mineral lease and sublease agreements described above, Dotiki and Warrior also reimbursed SGP Land for SGP Land's base lease obligations. We reimbursed SGP Land $5,428,000, $4,395,000, and $3,922,000 for the years ended December 31, 2004, 2003 and 2002 respectively, for the base lease obligations. Dotiki and Warrior have recouped as earned royalties all advance minimum royalty payments made in accordance with these terms except for $216,000 as of December 31, 2004.

In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty 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 $479,000 and $568,000 for the years ended December 31, 2003 and 2002, respectively. The 2004 annual minimum royalty obligation of $300,000 was paid in January 2005. MC Mining has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2004.

We also have an option to lease and/or sublease certain reserves from SGP Land, which reserves are contiguous to Hopkins. Under the terms of the option to lease and sublease, we paid option fees of $1,368,000 and $684,000 during the years ended December 31, 2004 and 2003, respectively. The 2003 option fee of $684,000 was paid in January 2004 and is included in the due to affiliates balance as of December 31, 2003. The anticipated annual minimum royalty obligation is $684,000, payable in advance through 2009.

Special General Partner. Effective January 2001, Gibson entered into a noncancelable operating lease arrangement with our special general partner for its coal preparation plant and ancillary facilities. Based on the terms of the lease, Gibson has paid and will continue to make monthly payments of approximately $216,000 through January 2011. Lease expense was $2,595,000 for 2004, 2003 and 2002.

We have previously entered into and have maintained agreements with two banks to provide letters of credit in an aggregate amount of $25.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2004, we had $22.2 million in out-standing letters of credit. Our special general partner guarantees these letters of credit. Historically, we have compensated our special general partner a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. Our special general partner agreed to waive the guarantee fee in exchange for a parent guarantee from our intermediate partnership and Alliance Coal on the mineral lease and sublease with Dotiki and Warrior. We paid approximately $31,300 and $48,200 in guarantee fees to our special general partner for the years ended December 31, 2003 and 2002, respectively.

Elk Creek and Tunnel Ridge. On October 21, 2004, we announced an agreement, subject to finalization of definitive agreements, to enter into two separate coal leases, which cumulatively will increase our coal reserve holdings by 25%. The Elk Creek reserves (Elk Creek) are located in Hopkins County, Kentucky, and the Tunnel Ridge reserves (Tunnel Ridge) are located in Ohio County, West Virginia and Washington County, Pennsylvania. These leases are estimated to contain approximately 100 million tons of high-sulfur coal reserves. The lessor for both leases is our special general partner. We also announced plans to immediately begin the development process for these properties, which includes obtaining the necessary mining permits and securing sufficient coal sales commitments to justify the capital investment needed to bring these properties into production.

The Elk Creek reserve area encompasses approximately 9,000 acres and is contiguous to our Hopkins County Coal complex. The Elk Creek coal reserves are currently estimated to include approximately 30 million tons of high-sulfur coal. The Elk Creek mine will be an underground mining complex, that mines the West Kentucky No. 9 and No. 11 coal seams. It will utilize continuous mining units and employ room-and-pillar mining techniques. We intend to use the existing coal handling and other surface facilities owned by Hopkins County Coal. We anticipate the Elk Creek complex will employ as many as 250 individuals and produce up to 3.2 million tons of coal annually. We estimate total capital expenditures to develop Elk Creek to be approximately $65.0 million. In December, 2004, the board of directors of our managing general partner approved the capital expenditures associated with Elk Creek. Coal supply commitments are currently being pursued. Construction of the Elk Creek mining complex began in the first quarter of 2005. We expect to fund these capital expenditures with available cash and marketable securities on hand, future cash generated from operations and borrowings available under our revolving credit facility.

In December 2000, Hopkins County Coal entered into an option agreement to lease and/or sublease the Elk Creek reserves from our special general partner. Under the terms of the option to lease and sublease, Hopkins County Coal paid an option fee of $645,000 during the year ended December 31, 2000, and paid option fees of $684,000 during each of the years ended December 31, 2001, 2002 and 2004. The 2003 option fee of $684,000 was paid in January 2004. Upon exercise of the option to lease or sublease, Hopkins County Coal is obligated to make an additional five annual advance minimum royalty payments of $684,000 per year, which royalty is fully recoupable against earned royalties. The earned royalty rate under the lease and/or sublease is $0.25 per ton.

In January 2005, we acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC for approximately $500,000 and the assumption of reclamation liabilities from Alliance Resource Holdings, Inc., a company owned by our management. Tunnel Ridge, LLC controls through a coal lease agreement with the special general partner an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. The Tunnel Ridge reserve area encompasses approximately 50,571 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge, LLC began paying our special general partner an advance minimum royalty of $3.0 million per year, which advance royalty payments will be fully recoupable against earned royalties. The earned royalty rate under the coal lease is the greater of $0.75 per ton or 3.0% of the per ton gross sales price f.o.b. barge. The term of the coal lease is the earlier of 30 years or until exhaustion of all mineable and merchantable coal with termination rights after the initial four years of the coal lease.

Tunnel Ridge, LLC also controls, under a separate lease agreement with our special general partner, the rights to approximately 900 acres of surface land and other tangible assets. Under the terms of the lease agreement, Tunnel Ridge, LLC shall pay our special general partner an annual lease payment of $240,000 beginning January 1, 2005. The lease agreement has an initial term of four years, which term may be extended by Tunnel Ridge, LLC at the same annual lease payment rate, to be consistent with the term of the coal lease.

We have initiated the permitting process of the Tunnel Ridge reserve area. We anticipate that the Tunnel Ridge operation will use a longwall miner for the majority of its coal extraction as well as continuous mining units used for preparation of the mine for future longwall mining. We estimate the Tunnel Ridge operation will be designed to produce up to six million tons of coal annually. We believe production from Tunnel Ridge may begin as early as 2008. We anticipate the Tunnel Ridge complex will employ as many as 300 individuals. We estimate total capital expenditures required to develop Tunnel Ridge to be approximately $200 million over a five-year period. We currently expect to fund these capital expenditures with available cash and marketable securities, future cash generated from operations and borrowings available under our revolving credit facility. A definitive commitment to develop Tunnel Ridge is dependent upon final approval by the board of directors of our managing general partner.

The Elk Creek and Tunnel Ridge transactions described above are related-party transactions and, as such, were reviewed by the board of directors of our managing general partner and its conflicts committee. Based upon these reviews, it was determined that these transactions reflect market-clearing terms and conditions customary in the coal industry. As a result, the board of directors of our managing general partner and its conflicts committee approved the Elk Creek and Tunnel Ridge transactions as fair and reasonable to us.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $101.1 million and $77.8 million at December 31, 2004 and 2003. These accruals were chiefly comprised of workers' compensation benefits, black lung benefits, and costs associated with reclamation and mine closings. 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 affected by changes to these liabilities. Please see "Item 8. Financial Statements and Supplementary Data. - Note 14. Reclamation and Mine Closing Costs and Note 15. Pneumoconiosis ("Black Lung") Benefits."

Pension Plan

We maintain a Pension Plan, which covers certain employees at the mining operations.

Our pension expense was approximately $2,751,000 and $3,049,000 for the years ended December 31, 2004 and 2003, respectively. The pension expense is based upon a number of actuarial assumptions, including an expected long-term rate of returns on our Pension Plan assets of 8.0% and 8.0% and discount rates of 6.25% and 6.75% for the years ended December 31, 2004 and 2003, respectively. Our actual return on plan assets was 11.9% and 25.9% for the years ended December 31, 2004 and 2003, respectively. Additionally, we base our determination of pension expense on an unsmoothed market-related valuation of assets equal to the fair value of assets, which immediately recognizes all investment gains or losses.

In developing our expected long-term rate of return assumption, we evaluated input from our investment manager, including their review of asset class return expectations by economists, and our actuary. At January 1, 2005, our expected long-term return assumption is at least 8.0%. Our advisors base the projected returns on broad equity and bond indices. Our expected long-term rate of return on Pension Plan assets is based on an asset allocation assumption of 80.0% with equity managers, with an expected long-term rate of return of 10.4%, and 20.0% with fixed income managers, with an expected long-term rate of return of 5.4%. The pension plan trustee regularly reviews our actual asset allocation in accordance with our investment guidelines and periodically rebalanced our investments to our targeted allocation when considered appropriate. The investment committee reviews our asset allocation with the compensation committee annually.

The discount rate that we utilize for determining our future pension obligation is based on a review of currently available high-quality fixed-income investments that receive one of the two highest ratings given by a recognized rating agency. We have historically used the average monthly yield for December of an Aa-rated utility bond index as the primary benchmark for establishing the discount rate. The duration of the bonds that comprise this index is comparable to the duration of the benefit obligation in the Pension Plan. The discount rate determined on this basis decreased from 6.25% at December 31, 2003 to 5.75% at December 31, 2004.

We estimate that our Pension Plan expense and cash contributions will be approximately $3,240,000 and $2,700,000, respectively in 2005. Future actual pension expense and contributions will depend on future investment performance, changes in future discount rates and various other factors related to the employees participating in the Pension Plan.

Lowering the expected long-term rate of return assumption by 1.0% (from 8.0% to 7.0%) at December 31, 2003 would have increased our pension expense for the year ended December 31, 2004 by approximately $211,000. Lowering the discount rate assumption by 0.5% (from 6.25% to 5.75%) at December 31, 2003 would have increased our pension expense for the year ended December 31, 2004 by approximately $422,000.

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 three years in the period ended December 31, 2004. However, in 2004 an increase in the cost of steel, power and fuel has increased, directly and indirectly, our materials, supplies and maintenance costs.

New Accounting Standards

In November 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 151, *Inventory Costs.* SFAS No. 151 is an amendment of Accounting Research Bulletin (ARB) No. 43, chapter 4, paragraph 5 that deals with inventory pricing. SFAS No. 151 clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs, and spoilage. Under previous guidance, paragraph 5 of ARB No. 43, chapter 4, items such as idle facility expense, excessive spoilage, double freight, and rehandling costs might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. This Statement eliminates the criterion of "so abnormal" and requires that those items be recognized as current period charges. Also, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS No. 151 is effective for fiscal years beginning after June 15, 2005. We are currently analyzing the requirements of SFAS No. 151 and believe that its adoption will not have any significant impact on our financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment.* SFAS No. 123R is a revision of SFAS No. 123, *Accounting for Stock Based Compensation,* and supersedes APB 25. Among other items, SFAS No. 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements.

The effective date of SFAS No. 123R is the first reporting period beginning after June 15, 2005, and we expect to adopt SFAS No. 123R effective July 1, 2005. SFAS No. 123R permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R for all share-based payments granted after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permits entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS No. 123. We are currently evaluating the appropriate transition method.

As permitted by SFAS No. 123, we currently account for share based payments to employees using the APB No. 25 intrinsic method and related FASB Interpretation No. 28 based upon the current market value of our common units at the end of each period. We have recorded compensation expense of $20,320,000, $7,687,000 and $2,338,000 for the years ended December 31, 2004, 2003 and 2002, respectively. SFAS No. 123R does not permit entities to continue to use the intrinsic method, we have not yet determined which model we will use to measure the fair value of restricted unit-based compensation upon the adoption of SFAS No. 123R.

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

- A substantial or extended decline in coal prices could negatively impact our results of operations.
- A material portion of our net income and cash flow is dependent on the continued ability by us or others to realize benefits from state and federal tax credits. If the benefit to us from any of these tax credits is materially reduced, it could have a material adverse effect on our operations and might impair our ability to pay the distributions on our units.
- 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.
- Newly constructed power plants may 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 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 coal synfuel cannot be assured.
- Coal mining is subject to inherent risks that are beyond our control and these risks may not be fully covered under our insurance policies. These risks include fires and explosions from methane, natural disasters like floods, mining and processing equipment failures, changes or variations in geologic conditions, inability to acquire mining rights or permits, employee injuries or fatalities, and labor-related interruptions.

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

- 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 will 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 cash 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

- The president and chief executive officer of our managing general partner effectively controls us through his ownership of a majority of the equity interests in our managing general partner and affiliates.

- 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 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.

- Our general partners and their affiliates, which are controlled by our management, may in some instances engage in activities that compete directly with us.

Regulatory Risks

- 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 state and federal legislation responsive to concerns over emissions of greenhouse gases such as carbon dioxide 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 through coal refuse disposal under the underground injection control program or regulation of our public drinking water systems.
- 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

- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our unitholders and our ability to make payments on our debt securities.
- 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 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, please see "Item 1. Business. – Coal Marketing and Sales" and "Item 8. Financial Statements and Supplementary Data. – Note 17. 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.

At the current time, we do not have any interest rate, foreign currency exchange rate or commodity price-hedging transactions outstanding.

On August 22, 2003, our intermediate partnership completed an $85 million revolving credit facility which replaces a $100 million credit facility. Borrowings under the credit facility and the previous credit facility are and were at variable rates and, as a result, we have interest rate exposure. Our earnings are not materially affected by changes in interest rates. We had no borrowings outstanding under the Credit Facility during 2004 or at December 31, 2004.

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, 2004, and 2003. The carrying amounts and fair values of financial instruments are as follows (in thousands):

Expected Maturity Dates as of December 31, 2004	**2005**	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Total**	**Fair Value December 31, 2004**
Senior Notes fixed rate	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 90,000	$ 180,000	$ 197,278
Weighted Average interest rate	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%		

Expected Maturity Dates as of December 31, 2003	**2004**	**2005**	**2006**	**2007**	**2008**	**Thereafter**	**Total**	**Fair Value December 31, 2003**
Senior Notes fixed rate	$ –	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 108,000	$180,000	$ 204,604
Weighted Average interest rate		8.31%	8.31%	8.31%	8.31%	8.31%		

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2004 and 2003, and the related consolidated statements of income, cash flows and Partners' capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 15, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Partnership's internal control over financial reporting and an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Tulsa, Oklahoma
March 15, 2005

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2004 AND 2003
(In thousands, except unit data)

	December 31,	
	2004	2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 31,177	$ 10,156
Trade receivables, less allowance of $0 and $763 at December 31, 2004 and 2003	56,967	36,374
Other receivables	1,637	1,931
Marketable securities	49,397	23,615
Inventories	13,839	14,527
Advance royalties	3,117	1,108
Prepaid expenses and other assets	4,345	3,432
Total current assets	160,479	91,143
PROPERTY, PLANT AND EQUIPMENT, AT COST	526,468	474,357
LESS ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION	(292,900)	(251,567)
Total property, plant and equipment	233,568	222,790
OTHER ASSETS:		
Advance royalties	11,737	12,439
Coal supply agreements, net	2,723	5,445
Other long-term assets	4,277	4,637
Total other assets	18,737	22,521
TOTAL ASSETS	$ 412,784	$ 336,454
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 30,961	$ 22,651
Due to affiliates	10,338	13,546
Accrued taxes other than income taxes	10,742	10,375
Accrued payroll and related expenses	11,730	11,095
Accrued interest	5,402	5,402
Workers' compensation and pneumoconiosis benefits	7,081	5,905
Other current liabilities	12,051	5,739
Current maturities, long-term debt	18,000	–
Total current liabilities	106,305	74,713
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	162,000	180,000
Pneumoconiosis benefits	19,833	17,131
Workers' compensation	25,994	23,321
Reclamation and mine closing	32,838	21,717
Due to affiliates	7,457	3,735
Other liabilities	3,170	3,280
Total long-term liabilities	251,292	249,184
Total liabilities	357,597	323,897
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL:		
Common Unitholders 18,130,440 and 14,692,527 units outstanding, respectively	363,658	263,071
Subordinated Unitholder -0- and 3,211,266 units outstanding, respectively	–	58,411
General Partners' deficit	(303,295)	(305,034)
Unrealized loss on marketable securities	(54)	(102)
Minimum pension liability	(5,122)	(3,789)
Total Partners' capital	55,187	12,557
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 412,784	$ 336,454

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2004	2003	2002
SALES AND OPERATING REVENUES:			
Coal sales	$ 599,399	$ 501,596	$ 479,515
Transportation revenues	29,817	19,553	18,992
Other sales and operating revenues	24,073	21,598	20,385
Total revenues	653,289	542,747	518,892
EXPENSES:			
Operating expenses	436,471	368,835	367,567
Transportation expenses	29,817	19,553	18,992
Outside purchases	9,913	8,508	10,077
General and administrative	45,400	28,270	20,337
Depreciation, depletion and amortization	53,664	52,495	52,408
Interest expense (net of interest income and interest capitalized of $852, $545 and $1,353 for the Partnership's respective periods)	14,963	15,981	16,360
Net gain from insurance settlement	(15,217)	–	–
Total operating expenses	575,011	493,642	485,741
INCOME FROM OPERATIONS	78,278	49,105	33,151
OTHER INCOME	984	1,374	540
INCOME BEFORE INCOME TAXES	79,262	50,479	33,691
INCOME TAX EXPENSE (BENEFIT)	2,641	2,577	(1,094)
NET INCOME	$ 76,621	$ 47,902	$ 34,785
ALLOCATION OF NET INCOME:			
PORTION APPLICABLE TO WARRIOR COAL EARNINGS (LOSS) PRIOR TO ITS ACQUISITION ON FEBRUARY 14, 2003	$ –	$ (666)	$ (1,504)
PORTION APPLICABLE TO PARTNERS' INTEREST	76,621	48,568	36,289
NET INCOME	$ 76,621	$ 47,902	$ 34,785
GENERAL PARTNERS' INTEREST IN NET INCOME (LOSS)	$ 3,324	$ 306	$ (778)
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 73,297	$ 47,596	$ 35,563
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 4.09	$ 2.71	$ 2.31
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 3.98	$ 2.62	$ 2.24
DISTRIBUTIONS PAID PER COMMON AND SUBORDINATED UNIT	$ 2.4875	$ 2.10	$ 2.00
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING—BASIC	17,940,948	17,580,734	15,405,311
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING—DILUTED	18,437,168	18,162,839	15,842,708

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 76,621	$ 47,902	$ 34,785
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	53,664	52,495	52,408
Reclamation and mine closings	1,622	1,341	1,365
Coal inventory adjustment to market	488	687	48
Other	255	(353)	(1,014)
Changes in operating assets and liabilities:			
Trade receivables	(20,593)	(3,459)	(222)
Other receivables	294	(1,828)	(242)
Inventories	200	(2,049)	(104)
Advance royalties	(1,307)	2,227	(311)
Accounts payable	8,678	(679)	(4,144)
Due to affiliates	14,194	9,978	14,080
Accrued taxes other than income taxes	367	2,270	1,936
Accrued payroll and related benefits	635	1,091	1,348
Accrued pneumoconiosis benefits	2,702	1,064	1,452
Workers' compensation	3,849	4,002	2,568
Other	3,386	(4,377)	(2,647)
Total net adjustments	68,434	62,410	66,521
Net cash provided by operating activities	145,055	110,312	101,306
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of property, plant and equipment	(54,713)	(43,004)	(67,339)
Purchase of Warrior Coal	–	(12,661)	–
Proceeds from sale of property, plant and equipment	687	913	323
Purchase of marketable securities	(49,271)	(23,091)	–
Proceeds from marketable securities	23,537	–	10,085
Proceeds from assumption of liability	2,112	–	–
Net cash used in investing activities	(77,648)	(77,843)	(56,931)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from common unit offering to public	–	53,927	–
Cash contribution by General Partners	3	9	–
Payments on Warrior Coal revolving credit balance	–	(17,000)	–
Borrowings under revolving credit and working capital facilities	–	31,600	66,400
Payments under revolving credit and working capital facilities	–	(31,600)	(66,400)
Payments on long-term debt	–	(31,250)	(15,000)
Distributions to Partners	(46,389)	(37,027)	(31,440)
Net cash used in financing activities	(46,386)	(31,341)	(46,440)
NET CHANGE IN CASH AND CASH EQUIVALENTS	21,021	1,128	(2,065)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	10,156	9,028	11,093
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 31,177	$ 10,156	$ 9,028
SUPPLEMENTAL CASH FLOW INFORMATION:			
CASH PAID FOR:			
Cash paid for interest	$ 15,229	$ 15,960	$ 17,294
Cash paid to taxing authorities	$ 2,150	$ 2,681	$ –
NON-CASH ACTIVITY:			
Market value of common units issued to Long-Term Incentive Plan participants upon vesting	$ 13,680	$ –	$ –

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL (DEFICIT) AND COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002
(In thousands, except unit data)

	Number of Limited Partner Units							Total
	Common	Subordinated	Common	Subordinated	General Partners' (Deficit)	Unrealized Gain (Loss)	Minimum Pension Liability	Partners' Capital (Deficit)
Balance at January 1, 2002	8,982,780	6,422,531	$ 141,448	$ 110,935	$ (289,065)	$ (74)	$ (814)	$ (37,570)
Comprehensive income:								
Net income (loss)	–	–	20,737	14,826	(778)	–	–	34,785
Unrealized loss	–	–	–	–	–	(76)	–	(76)
Minimum pension liability	–	–	–	–	–	–	(4,461)	(4,461)
Total comprehensive income	–	–	20,737	14,826	(778)	(76)	(4,461)	30,248
Distribution to Partners	–	–	(17,966)	(12,845)	(629)	–	–	(31,440)
Balance at December 31, 2002	8,982,780	6,422,531	144,219	112,916	(290,472)	(150)	(5,275)	(38,762)
Comprehensive income:								
Net income	–	–	31,346	16,250	306	–	–	47,902
Unrealized gain	–	–	–	–	–	48	–	48
Minimum pension liability	–	–	–	–	–	–	1,486	1,486
Total comprehensive income	–	–	31,346	16,250	306	48	1,486	49,436
Issuance of units to public	2,538,000	–	53,927	–	–	–	–	53,927
General Partners contribution	–	–	–	–	9	–	–	9
Retirement of common units contributed by Managing General Partner	(39,518)	–	(890)	–	890	–	–	–
Subordinated units conversion to common units	3,211,265	(3,211,265)	57,268	(57,268)	–	–	–	–
Warrior Coal purchase	–	–	–	–	(15,026)	–	–	(15,026)
Distribution to Partners	–	–	(22,799)	(13,487)	(741)	–	–	(37,027)
Balance at December 31, 2003	14,692,527	3,211,266	263,071	58,411	(305,034)	(102)	(3,789)	12,557
Comprehensive income:								
Net income	–	–	60,685	12,612	3,324	–	–	76,621
Unrealized gain	–	–	–	–	–	48	–	48
Minimum pension liability	–	–	–	–	–	–	(1,333)	(1,333)
Total comprehensive income	–	–	60,685	12,612	3,324	48	(1,333)	75,336
Issuance of units to Long-Term Incentive Plan participants upon vesting	231,126	–	13,680	–	–	–	–	13,680
General Partners contribution	–	–	–	–	3	–	–	3
Retirement of common units contributed by Managing General Partner	(4,479)	–	(265)	–	265	–	–	–
Distribution to Partners	–	–	(36,548)	(7,988)	(1,853)	–	–	(46,389)
Subordinated units conversion to common units	3,211,266	(3,211,266)	63,035	(63,035)	–	–	–	–
Balance at December 31, 2004	18,130,440	–	$ 363,658	$ –	$ (303,295)	$ (54)	$ (5,122)	$ 55,187

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

1. ORGANIZATION AND PRESENTATION

Alliance Resource Partners, L.P., a Delaware limited partnership (the "Partnership") was formed in May 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.

The Delaware limited partnerships, limited liability companies and corporation that comprise the Partnership's subsidiaries 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, Warrior Coal, LLC, Webster County Coal, LLC, and White County Coal, LLC.

The Partnership completed its initial public offering (the "IPO") in August 1999, issuing 7,750,000 Common Units ("Common Units") at $19.00 per unit and received net proceeds of $133.7 million. Concurrently with the offering ARH contributed certain assets to the Partnership in exchange for cash, 0.01% general partner interest in each of the Partnership and the Intermediate Partnership, the right to receive incentive distributions as defined in the partnership agreement and the assumption of related indebtedness and 1,232,780 Common Units and 6,422,531 Subordinated Units, that converted into Common Units during November 2004 and 2003 (Note 9), held by Alliance Resource GP, LLC, a Delaware limited liability company and wholly-owned subsidiary of ARH (the "Special GP"). On February 14, 2003 and March 14, 2003, the Partnership issued 2,250,000 and 288,000 additional Common Units at a public offering price of $22.51 per unit and received net proceeds of $48.5 million and $6.2 million, respectively, before expenses of approximately $0.8 million, excluding underwriters fees. In November 2003, 3,211,265 outstanding Subordinated Units were converted to Common Units in accordance with the partnership agreement. In November 2004, the remaining 3,211,266 subordinated units converted to Common Units and the Partnership issued 231,126 additional Common Units pursuant to the Long-Term Incentive Plan (Note 13). If at any time not more than twenty percent of the then-issued and outstanding limited partner interests are held by persons other than the general partners and their affiliates, the managing general partner will have the right to acquire all, but not less than all, of the remaining limited partner interest held by unaffiliated persons.

On February 14, 2003, the Partnership acquired Warrior Coal, LLC ("Warrior Coal") (Note 3). Because the Warrior Coal acquisition was between entities under common control, the acquisition was recorded at historical cost in a manner similar to that used in a pooling of interests. Accordingly, the consolidated financial statements and accompanying notes of the Partnership as of December 31, 2002 and for the year ended December 31, 2002 have been restated to reflect the combined historical results of operations, financial position and cash flows of the Partnership and Warrior Coal. ARH Warrior Holdings, Inc. ("ARH Warrior Holdings"), a subsidiary of ARH, acquired Warrior Coal on January 26, 2001.

The Partnership is managed by Alliance Resource Management GP, LLC, a Delaware limited liability company (the "Managing GP"), which holds a 0.99% and 1.0001% managing general partner interest in the Partnership and the Intermediate Partnership, respectively.

The accompanying consolidated financial statements include the accounts and operations of the limited partnerships, limited liability companies and corporation disclosed above and present the financial position as of December 31, 2004 and 2003 and the results of their operations, cash flows and changes in partners' capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2004. All material intercompany transactions and accounts of the Partnership have been eliminated.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Estimates — The preparation of consolidated 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 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, 2004 and 2003, the estimated fair value of long-term debt was approximately $197.3 million and $204.6 million, respectively. The fair value of long-term debt is based on interest rates that management believes 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 $2,192,000 and $1,257,000 at December 31, 2004 and 2003, respectively, to accounts payable in the consolidated balance sheets.

Marketable Securities — The Partnership currently classifies all marketable securities as available-for-sale securities. At December 31, 2004 and 2003, the cost of marketable securities are reported at fair value with unrealized gains and losses reported as a component of Partners' capital until realized. The Partnership has restricted investments of $1,816,000 and $1,809,000 at December 31, 2004 and 2003, respectively, which are included in other assets in the consolidated balance sheets. The restricted marketable securities are held in escrow and secure reclamation bonds (Note 5).

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 2 to 13 years. Depreciable lives for mining equipment and processing facilities range from 2 to 13 years. Depreciable lives for land and land improvements and depletable lives for mineral rights range from 5 to 13 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 13 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, 2004 and 2003, land and mineral rights include $2,030,000 and $2,178,000, respectively, 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. Management believes that the carrying value of these reserves will be recovered.

Mine Development Costs — Mine development costs are capitalized and amortized over the estimated life of the mine.

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.

In June 2003, the Partnership idled the active surface mine at its Hopkins County Coal mining complex in response to soft market demand. In October 2004, the surface mine was re-opened in response to incremental sales opportunities from existing customers as well as strong market demand for Illinois Basin region coal. While the Hopkins County Coal mining complex was idled the Partnership evaluated the recoverability of the appropriate asset group and concluded that there was no impairment loss.

Advance Royalties — Rights to coal mineral leases are often acquired and/or maintained 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.

In March 2004, the Financial Accounting Standard Board ("FASB") issued Emerging Issues Task Force Issue No. 04-2, *Whether Mineral Rights Are Tangible or Intangible Assets.* In this Issue, the Task Force reached the consensus that mineral rights are tangible assets and amended Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets,* which previously classified mineral rights as intangible assets. Consistent with other extractive industry entities, the Partnership has historically included its related assets as tangible, therefore there was no material effect on the Partnership's consolidated financial statements upon adoption.

Coal Supply Agreements — A portion of the acquisition costs from a business combination in 1996 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 $35,740,000 and $33,018,000 at December 31, 2004 and 2003, respectively. The aggregate amortization expense recognized for coal supply agreements was $2,722,000, $2,722,000 and $3,864,000 for the years ended December 31, 2004, 2003 and 2002, respectively. The estimated aggregate amortization expense for 2005 is approximately $2,723,000.

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 pits 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.

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.

Income Taxes — The Partnership is not a taxable entity for federal or state income tax purposes; the tax effect of its activities accrues to the unitholders. Although publicly traded partnerships will, as a general rule, be taxed as corporations, the Partnership qualifies for an exemption because at least 90% of its income consists of qualifying income. 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 Partnership's subsidiary, Alliance Service, Inc. ("Alliance Service"), is subject to federal and state income taxes. Prior to the Partnership's acquisition of Warrior Coal, the financial results of Warrior Coal were subject to federal and state income taxes. The federal and state income taxes associated with Warrior Coal's financial results from January 26, 2001, the date of ARH Warrior Holdings' acquisition of Warrior Coal, to February 14, 2003, the date of the Partnership's acquisition of Warrior Coal, are included in income taxes. The Partnership's tax counsel has provided an opinion that the Partnership, the Intermediate Partnership and the holding company will each be treated as a partnership. However, as is customary, no ruling has been or will be requested from the IRS regarding the Partnership's classification as a partnership for federal income tax purposes.

Revenue Recognition — Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer's analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, the Partnership estimates the amount of the quality adjustment and adjusts the estimate to actual when the information is provided by the customer. Historically such adjustments have not been material. Non-coal sales revenues primarily consist of rental and service fees associated with agreements to host and operate a third-party coal synfuel facility and to 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.

Common Unit-Based Compensation — The Partnership accounts for the compensation expense of the non-vested restricted common units granted under the Long-Term Incentive Plan (Note 12) using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB 25") and the related Financial Accounting Standards Board Interpretation No. 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans* ("FASB Interpretation No. 28"). Compensation cost for the restricted common units is recorded on a pro-rata basis, as appropriate given the "cliff vesting" nature of the grants, based upon the current market value of the Partnership's common units at the end of each period.

Consistent with the disclosure requirements of SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure,* and amendment of SFAS No. 123, *Accounting for Stock-Based Compensation,* the following table provides pro forma results as if the fair value-based method had been applied to all outstanding and non-vested awards, including Long-Term Incentive Plan units, in each period presented (in thousands, except per unit data):

	Year Ended December 31,		
	2004	**2003**	**2002**
Net income, as reported	$ 76,621	$ 47,902	$ 34,785
Add: compensation expenses related to Long-Term Incentive Plan units included in reported net income	20,320	7,687	2,338
Deduct: compensation expense related to Long-Term Incentive Plan units determined under fair value method for all awards	(3,915)	(3,632)	(2,257)
Net income, pro forma	93,026	51,957	34,866
General partners' interest in net income (loss), pro forma	3,652	386	(777)
Limited partners' interest in net income, pro forma	$ 89,374	$ 51,571	$ 35,643
Earnings per limited partner unit:			
Basic, as reported	$ 4.09	$ 2.71	$ 2.31
Basic, pro forma	$ 4.98	$ 2.93	$ 2.38
Diluted, as reported	$ 3.98	$ 2.62	$ 2.24
Diluted, pro forma	$ 4.85	$ 2.84	$ 2.32

The total accrued liability associated with the Long-Term Incentive Plan as of December 31, 2004 and 2003 was $10,013,000 and $12,493,000, respectively, and is included in the current and long-term due to affiliates liabilities in the consolidated balance sheets. See New Accounting Standards discussion below concerning the impact of SFAS No. 123R, *Share-Based Payment,* on accounting for the Long-Term Incentive Plan.

Net Income Per Unit — Basic net income per limited partner unit is determined by dividing Limited Partners' interest in net income (Note 11), by the weighted average number of outstanding Common Units and Subordinated Units. Warrior Coal's earnings (loss) prior to the Partnership's acquisition on February 14, 2003 was allocated entirely to the general partner. 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 13).

Segment Reporting — The Partnership has no reportable segments due to its operations consisting solely of producing and marketing coal and providing rental and service fees associated with producing and marketing coal synfuel, which meets the aggregation criteria of SFAS No. 131, *Disclosures About Segments of an Enterprise and Related Information.* The Partnership has disclosed major customer sales information (Note 18). The Partnership's geographic areas of operation are concentrated in the United States.

New Accounting Standards — In November 2004, the FASB issued SFAS No. 151, *Inventory Costs.* SFAS No. 151 is an amendment of Accounting Research Bulletin ("ARB") No. 43, chapter 4, paragraph 5 that deals with inventory pricing. SFAS No. 151 clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs, and spoilage. Under previous guidance, paragraph 5 of ARB No. 43, chapter 4, items such as idle facility expense, excessive spoilage, double freight, and rehandling costs might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. This Statement eliminates the criterion of "so abnormal" and requires that those items be recognized as current period charges. Also, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS No. 151 is effective for fiscal years beginning after June 15, 2005. The Partnership is analyzing the requirements of SFAS No. 151 and believes that its adoption will not have any significant impact on the Partnership's financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment.* SFAS No. 123R is a revision of SFAS No. 123, *Accounting for Stock Based Compensation,* and supersedes APB 25. Among other items, SFAS No. 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements.

The effective date of SFAS No. 123R is the first reporting period beginning after June 15, 2005, and the Partnership expects to adopt SFAS No. 123R effective July 1, 2005. SFAS No. 123R permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R for all share-based payments granted after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permits entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS No. 123. The Partnership is currently evaluating the appropriate transition method.

As permitted by SFAS No. 123, the Partnership currently accounts for share based payments to employees using the APB No. 25 intrinsic method and related FASB Interpretation No. 28 based upon the current market value of the Partnership's common units at the end of each period. The Partnership has recorded compensation expense of $20,320,000, $7,687,000 and $2,338,000 for the years ended December 31, 2004, 2003 and 2002, respectively. SFAS No. 123R does not permit entities to continue to use the intrinsic method, the Partnership has not yet determined which model it will use to measure the fair value of restricted unit-based compensation upon the adoption of SFAS No. 123R.

Reclassifications — Certain reclassifications have been made to the 2003 balance sheet presentation of receivables, pneumoconiosis benefits and workers' compensation long-term liabilities to conform to the 2004 classifications.

3. ACQUISITIONS

Warrior Coal. On February 14, 2003, Warrior Coal was acquired from an affiliate, ARH Warrior Holdings, a subsidiary of ARH, pursuant to an Amended and Restated Put and Call Option Agreement ("Put/Call Agreement"). Warrior Coal purchased the capital stock of Roberts Bros. Coal Co., Inc., Warrior Coal Mining Company, Warrior Coal Corporation and certain assets of Christian Coal Corp. and Richland Mining Co., Inc. in January 2001. The Managing GP originally declined the opportunity to purchase these assets 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 Warrior Holdings enter into a put and call arrangement for Warrior Coal. ARH Warrior Holdings and the Partnership, with the approval of the Conflicts Committee of the Managing GP, entered into the Put/Call Agreement in January 2001. Concurrently, ARH Warrior Holdings acquired Warrior Coal in January 2001 for $10.0 million.

The Put/Call Agreement preserved the opportunity for the Partnership to acquire Warrior Coal during a specified time period. Under the terms of the Put/Call Agreement, ARH Warrior Holdings exercised its put option requiring the Partnership to purchase Warrior Coal at a put option price of approximately $12.7 million.

The option provisions of the Put/Call Agreement were subject to certain conditions (unless otherwise waived), including, among others, (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 reflected 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 were exercised. In January 2001 and in December 2002, the Partnership 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 included, among others, (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below the then current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, as of the date of the acquisition and at December 31, 2002 and 2001, the Partner-ship believed that the fair value of Warrior Coal was equal to or greater than the put option exercise price.

The put option price of $12.7 million was paid to ARH Warrior Holdings in accordance with the terms of the Put/Call Agreement. In addition, the Partnership repaid Warrior Coal's borrowings of $17.0 million under the revolving credit agreement between the Special GP and Warrior Coal. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior Coal that have contributed to improved productivity and significantly increased capacity. The Partnership funded the Warrior Coal acquisition through a portion of the proceeds received from the issuance of 2,250,000 Common Units (Note 1). Because the Warrior Coal acquisition was between entities under common control, it has been accounted for at historical cost in a manner similar to that used in a pooling of interests.

Under the terms of the Put/Call Agreement, the Partnership assumed certain other obligations, including a mineral lease and sublease with SGP Land, LLC ("SGP Land"), a subsidiary of the Special GP, covering coal reserves that have been and will continue to be mined by Warrior Coal. The terms and conditions of the mineral lease and sub-lease remained unchanged (Note 16).

Lodestar. On July 15, 2003, Hopkins County Coal, LLC ("Hopkins County Coal") executed an Asset Purchase Agreement with Lodestar Energy, Inc. ("Lodestar"), a coal company operating in Chapter 7 bankruptcy proceedings. Concurrently, Hopkins County Coal entered into various other agreements (collectively, the Asset Purchase Agreement and the various other agreements are referred to as the "Lodestar Agreements") with several parties, including the Kentucky Environmental and Public Protection Cabinet ("Cabinet") and Frontier Insurance Company ("Frontier"). Closing of the Lodestar Agreements was subject to the resolution of numerous contingencies and/or conditions. Under the terms of the relevant Lodestar Agreements, Hopkins County Coal principally acquired a mining pit, created by Lodestar's mining activities. The mining pit will be used for refuse disposal by the Partnership's Webster County Coal, LLC's Dotiki mine. The purchase price included a nominal monetary amount and the assumption of remedial reclamation activities under the various mining permits acquired by Hopkins County Coal from Lodestar. The Cabinet accepted these remedial activities in lieu of certain solid waste closure requirements applicable to residual landfills. Hopkins County Coal also received $2.1 million from Frontier in exchange for the assumption of the remedial activities associated with the mining pit. As a result of closing the Lodestar Agreements on June 2, 2004, Hopkins County Coal recorded the fair value of the asset retirement obligation of approximately $4.1 million with a corresponding asset that was reduced by the $2.1 million of cash received.

Elk Creek – Tunnel Ridge. On October 21, 2004, the Partnership announced an agreement, subject to finalization of definitive agreements, to enter into two separate coal leases, the Elk Creek reserves ("Elk Creek"), which are located in Hopkins County, Kentucky, and the Tunnel Ridge reserves ("Tunnel Ridge"), which are located in Ohio County, West Virginia and Washington County, Pennsylvania. These leases are estimated to contain approximately 100 million tons of high-sulfur coal reserves. The lessor for both leases is the Special GP. The Partnership also announced plans to immediately begin the development process for these properties, which includes obtaining the necessary mining permits and securing sufficient coal sales commitments to justify the capital investment needed to bring these properties into production.

The Elk Creek reserve area encompasses approximately 9,000 acres and is contiguous to the Partnership's Hopkins County Coal complex. The Elk Creek coal reserves are currently estimated to include approximately 30 million tons of high-sulfur coal. The Elk Creek mine will be an underground mining complex, mining the West Kentucky No. 9 and No. 11 coal seams. It will utilize continuous mining units and employ room-and-pillar mining techniques. The mine intends to use the existing coal handling and other surface facilities owned by Hopkins County Coal. The Partnership anticipates that the Elk Creek complex will employ as many as 250 individuals and produce up to 3.2 million tons of coal annually. The Partnership is estimating total capital expenditures to develop Elk Creek to be approximately $65.0 million. Coal supply commitments are currently being pursued. Construction of the Elk Creek mining complex began in the first quarter of 2005. The Partnership expects to fund these capital expenditures with available cash and marketable securities on hand, future cash generated from operations and/or borrowings available under the revolving credit facility.

In December 2000, Hopkins County Coal entered into an option agreement to lease and/or sublease the Elk Creek reserves from the Partnership's Special GP. Under the terms of the option to lease and sublease, Hopkins County Coal paid an option fee of $645,000 during the year ended December 31, 2000, and paid option fees of $684,000 during each of the years ended December 31, 2001, 2002 and 2004. The 2003 option fee of $684,000 was paid in January 2004. Upon exercise of the option to lease or sublease, Hopkins County Coal is obligated to make an additional five annual advance minimum royalty payments of $684,000 per year, which royalty is fully recoupable against earned royalties. The earned royalty rate under the lease and/or sublease is $0.25 per ton.

In January 2005, the Partnership acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC for approximately $500,000 and the assumption of reclamation liabilities from Alliance Resource Holdings, Inc., a company owned by management of the Partnership. Tunnel Ridge, LLC controls through a coal lease agreement with the Special GP an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. The Tunnel Ridge reserve area encompasses approximately 50,571 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge, LLC shall pay the Special GP an advance minimum royalty of $3.0 million per year. The advance royalty payments will be fully recoupable against earned royalties. The earned royalty rate under the coal lease is the greater of $0.75 per ton or 3.0% of theper ton gross sales price f.o.b. barge. The term of the coal lease is the earlier of 30 years or until exhaustion of all mineable andmerchantable coal. The Partnership has termination rights after the initial four years of the coal lease.

Tunnel Ridge, LLC also controls, under a separate lease agreement with the Special GP, the rights to approximately 900 acres of surface land and other tangible assets. Under the terms of the lease agreement, Tunnel Ridge, LLC shall pay to the Special GP an annual lease payment of $240,000 beginning January 1, 2005. The lease agreement has an initial term of four years, which may be extended by Tunnel Ridge, LLC, at the same annual lease payment rate, to be consistent with the term of the coal lease.

The Elk Creek and Tunnel Ridge transactions described above are related-party transactions and, as such, were reviewed by the Board of Directors of the Partnership's Managing GP and Conflicts Committee. Based upon these reviews, it was determined that these transactions reflect market-clearing terms and conditions customary in the coal industry. As a result, the Board of Directors of the Partnership's Managing GP and its Conflicts Committee approved the Elk Creek and Tunnel Ridge transactions as fair and reasonable to the Partnership and its limited partners.

4. MINE FIRE INCIDENTS

Dotiki Mine Fire. On February 11, 2004, Webster County Coal, LLC's ("Webster County Coal") Dotiki mine was temporarily idled for a period of twenty-seven calendar days following the occurrence of a mine fire that originated with a diesel supply tractor (the "Dotiki Fire Incident"). As a result of the firefighting efforts of the Mine Safety and Health Administration, Kentucky Department of Mines and Minerals, and Webster County Coal personnel, Dotiki successfully extinguished the fire and totally isolated the affected area of the mine behind permanent barriers. Initial production resumed on March 8, 2004. For the Dotiki Fire Incident, the Partnership had commercial property insurance that provided coverage for damage to property destroyed, interruption of business operations, including profit recovery, and expenditures incurred to minimize the period and total cost of disruption to operations.

On September 10, 2004, the Partnership filed a third and final proof of loss with the applicable insurance underwriters reflecting a settlement (the "Dotiki Settlement") of all expenses, losses and claims incurred by Webster County Coal and other affiliates arising from or in connection with the Dotiki Fire Incident (the "Dotiki Insurance Claim") in the aggregate amount of $27.0 million, inclusive of a $1.0 million self-retention, a $2.5 million deductible (collectively, the "Dotiki Insurance Deductibles") and 10% co-insurance (the "2004

Co-Insurance"). The 2004 Insurance Deductibles and 2004 Co-Insurance were allocated on a pro-rata basis to each of the three areas of insurance recoveries discussed below. In addition, the accounting for two net partial advance payments in the aggregate amount of $8.1 million and the final net payment of $13.05 million, exclusive of the 2004 Insurance Deductible and 2004 Co-Insurance, were subject to the accounting methodology described below. Specifically, the Partnership evaluated and accounted for the insurance recoveries in the following areas:

1. Expenses incurred as a result of the fire – The Partnership incurred extra expenses, expediting expenses, and other costs associated with extinguishing the fire in an aggregate amount of approximately $7.1 million. With application of $5.6 million of the insurance recovery proceeds, the Partnership recorded net expenses of approximately $1.5 million.
2. Damage to Dotiki mine property – The Partnership incurred damage to Dotiki's mine property (exclusive of any amounts relating to matters discussed in 1. above) of approximately $1.2 million, which property had a net book value of $138,000. Based on discussions with the underwriters culminating in the Dotiki Settlement, the Partnership recorded a net gain of approximately $785,000, reflecting the amount that the allocated insurance proceeds exceeded the net book value of the damaged property.
3. Dotiki mine business interruption costs and extra expense – Based on the negotiations with the underwriters leading to the Dotiki Settlement, the Partnership recorded a net gain of approximately $14.4 million for the recovery of business interruption costs and extra expenses stemming from the Dotiki Fire Incident. This net gain amount reflects an offset of approximately $200,000 for professional services expenses incurred in resolving the business interruption portion of the Dotiki Settlement.

Pursuant to the accounting methodology described above, the Partnership recorded (a) an offset to operating expenses of approximately $5.9 million and (b) a combined net gain of approximately $15.2 million for damage to property destroyed, interruption of business operations (including profit recovery), and extra expenses incurred to minimize the period and total cost of disruption to operations associated with the Dotiki Fire Incident.

MC Mining Mine Fire. On December 26, 2004, MC Mining, LLC's ("MC Mining") Excel No. 3 mine was temporarily idled following the occurrence of a mine fire (the "MC Mining Fire Incident"). The fire was discovered by mine personnel near the bottom of the Excel No. 3 mine slope late in the evening of December 25, 2004.

Under a firefighting plan developed by MC Mining, in cooperation with mine emergency response teams from the Mine Safety and Health Administration and Kentucky Office of Mine Safety and Licensing, the four portals at the Excel No. 3 mine were capped to deprive the fire of oxygen. A series of boreholes were then drilled into the fire area to further suppress the fire. As a result of these efforts, the mine atmosphere was rendered substantially inert, or without oxygen, and the Excel No. 3 mine fire was effectively suppressed. MC Mining then began construction of temporary and permanent barriers designed to completely isolate the mine fire area. When construction of the permanent barriers was completed, MC Mining began efforts to repair and rehabilitate the Excel No. 3 mine infrastructure. On February 21, 2005, the repair and rehabilitation efforts had progressed sufficiently to allow initial resumption of production. The Partnership anticipates that MC Mining may return to full production by the end of the first quarter of 2005, but we cannot assure that our ability to produce will not continue to be adversely impacted by the MC Mining Fire Incident for a period of time. The boreholes continue to be used to monitor the mine atmosphere and to inject nitrogen into the area of the fire now isolated behind the permanent barriers.

The Partnership maintains commercial property (including business interruption) insurance policies, which are renewed annually in September and provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles, (collectively the "2005 Deductibles") and 10% co-insurance ("2005 Co-Insurance"), however, the Partnership cannot give any assurances as to the eventual timing or amount of any recovery of proceeds under these policies. The Partnership has made an initial estimate of certain costs primarily associated with activities relating to the suppression of the fire and the resumption of operations. Operating expenses for the 2004 fourth quarter increased by $4.1 million reflecting an initial estimate of certain minimum costs attributable to the MC Mining Fire Incident that are not reimbursable under the Partnership's insurance policies due to the application of the 2005 Deductibles and 2005 Co-Insurance. An increase in the amount of such costs is possible, but is not currently subject to a reasonable estimate at this time. In addition to these initial cost estimates, the Partnership expects to incur additional out-of-pocket costs that will generally fall into the categories of extra expenses, expediting expenses and other areas of coverage under the commercial insurance policies. These future out-of-pocket costs, which are not currently subject to reasonable estimation, will be expensed as incurred. The related estimated insurance recovery of these costs will be recorded, net of the 2005 Deductibles and 2005 Co-Insurance, as the Partnership determines that such recoveries are probable. Any recovery under the insurance policies of business interruption proceeds attributable to amounts in excess of actual costs incurred will be recorded as gains when the claims are settled with the insurance underwriters.

5. MARKETABLE SECURITIES

Marketable securities include or have historically included Federal home loan discount notes, bankers acceptances, certificates of deposits and equity securities. At December 31, 2004 and 2003, the cost of the bankers acceptances and certificates of deposit approximated fair value and no effect of unrealized gains (losses) is reflected in Partners' capital. The Federal home loan discount notes and equity securities had a cumulative unrealized loss reflected in Partners' capital of $54,000 and $102,000 at December 31, 2004 and 2003, respectively.

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

	2004	2003
Federal home loan discount notes	$ 39,414	$ –
Bankers acceptances	9,983	–
Certificates of deposit	–	23,091
Equity securities	–	524
Total unrestricted marketable securities	$ 49,397	$ 23,615
Cash and cash equivalents	$ 1,816	$ 1,809
Total restricted marketable securities (included in other long-term assets)	$ 1,816	$ 1,809

6. INVENTORIES

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

	2004	2003
Coal	$ 4,822	$ 6,186
Supplies	9,017	8,341
	$ 13,839	$ 14,527

7. PROPERTY, PLANT AND EQUIPMENT

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

	2004	2003
Mining equipment and processing facilities	$ 448,571	$ 411,070
Land and mineral rights	22,281	20,705
Buildings, office equipment and improvements	46,281	36,786
Construction in progress	9,335	5,796
	526,468	474,357
Less accumulated depreciation, depletion and amortization	(292,900)	(251,567)
	$ 233,568	$ 222,790

8. LONG-TERM DEBT

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

	2004	2003
Senior notes	$ 180,000	$ 180,000
Less current maturities	(18,000)	–
	$ 162,000	$ 180,000

The Intermediate Partnership has $180 million principal amount of 8.31% senior notes due August 20, 2014, payable in ten equal annual installments of $18 million beginning in August 2005 with interest payable semiannually. On August 22, 2003, the Intermediate Partnership completed a $85 million revolving credit facility which expires September 30, 2006. The revolving credit facility replaced a $100 million credit facility that would have expired August 2004. The Partnership paid in full all amounts outstanding under the original credit facility with borrowings of $20 million under the new revolving credit agreement. The interest rate on the revolving credit facility is based on either the (i) London Interbank Offered Rate or (ii) the "Base Rate," which is equal to the greater of the JPMorgan Chase Prime Rate or the Federal Funds Rate plus 1/2 of 1%, plus, in either case, an applicable margin. The Partnership incurred certain costs aggregating $1.2 million associated with the revolving credit facility. These costs have been deferred and are being amortized as a component of interest expense over the term of the revolving credit facility. The Partnership had no borrowings outstanding under the revolving credit facility at December 31, 2004. Letters of credit can be issued under the revolving credit facility not to exceed $30 million; outstanding letters of credit reduce amounts available under the revolving credit facility. At December 31, 2004, the Partnership had letters of credit of $9.0 million outstanding under the revolving credit facility to secure the Partnership's obligations for reclamation liabilities and workers' compensation benefits.

The senior notes and revolving credit facility are guaranteed by all of the subsidiaries of the Intermediate Partnership. The senior notes and revolving credit facility contain various restrictive and affirmative covenants, including the amount of distributions by the Intermediate Partnership and the incurrence of other debt exceeding $35 million. The senior note restrictions on distributions are consistent with the Partnership Agreement and the credit facility limit borrowings to fund distributions to $25,000,000. The Partnership was in compliance with the covenants of both the revolving credit facility and senior notes at December 31, 2004.

The Partnership previously entered into and has maintained agreements with two banks to provide additional 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, 2004, the Partnership had $22.2 million in letters of credit outstanding under these agreements. The Special GP guarantees the letters of credit (Note 16).

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

Year Ending December 31,	
2005	$ 18,000
2006	18,000
2007	18,000
2008	18,000
2009	18,000
Thereafter	90,000
	$ 180,000

9. DISTRIBUTIONS OF AVAILABLE CASH AND CONVERSION OF SUBORDINATED UNITS

The Partnership Agreement provides for the conversion of the Subordinated Units into Common Units after meeting certain financial tests. The Partnership satisfied, in two stages, the financial tests that resulted in the Subordinated Units being converted into Common Units. First, the Partnership satisfied certain financial tests that provided for the early conversion of one-half of the Subordinated Units (i.e. 3,211,265 Subordinated Units) to Common units in September 2003. Second, the Partnership satisfied the final conversion financial tests for converting the remaining Subordinated Units (i.e. 3,211,266 Subordinated Units) to Common Units in September 2004. The Board of Directors (and its Conflicts Committee) for the Managing GP approved management's determination that the early conversion financial tests and the final conversion financial tests were met. As a result, one-half of the Subordinated Units converted into Common Units on November 15, 2003 and the remaining one-half of the Subordinated Units converted into Common Units on November 2, 2004.

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.

As quarterly distributions of available cash exceed the minimum quarterly distribution ("MQD") and target distributions levels as established in the Partnership Agreement, the Managing GP receives distributions based on specified increasing percentages of the available cash that exceed the MQD and the target distribution levels. The Partnership Agreement defines the MQD as $0.50 per unit ($2.00 per unit on an annual basis). 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 the MQD and common unit arrearages, if any.

Under the quarterly incentive distribution provisions of the partnership agreement, the Managing GP is entitled to receive 15% of the amount the Partnership distributes in excess of $0.55 per unit, 25% of the amount the Partnership distributes in excess of $0.625 per unit, and 50% of the amount the Partnership distributes in excess of $0.75 per unit. During 2004 the Partnership allocated to the Managing GP incentive distributions of $1,828,000. There were no incentive distributions allocated to the Managing GP during the years ended December 31, 2003 and 2002. The following table summarizes the quarterly per unit distribution paid during the respective quarter.

	Year		
	2004	2003	2002
First Quarter	$0.5625	$0.5250	$0.5000
Second Quarter	$0.6250	$0.5250	$0.5000
Third Quarter	$0.6500	$0.5250	$0.5000
Fourth Quarter	$0.6500	$0.5250	$0.5000

On January 27, 2005, the Partnership declared a quarterly distribution of $0.75 per unit, totaling approximately $14,797,000 (which includes the Managing GP's portion of incentive distributions), payable on February 14, 2005, to all unitholders of record on February 7, 2005.

10. INCOME TAXES

The Partnership's subsidiary, Alliance Service, is subject to federal and state income taxes. In conjunction with a decision to relocate the coal synfuel facility from Hopkins County Coal to Warrior Coal, agreements for a portion of the services provided to the coal synfuel producer were assigned to Alliance Service in December 2002. Alliance Service has no temporary differences between the financial reporting basis and the tax basis of its assets and liabilities. Prior to the Partnership's acquisition of Warrior Coal, the financial results of Warrior Coal were subject to federal and state income taxes. The federal and state income taxes associated with Warrior Coal's financial results prior to the Partnership's acquisition on February 14, 2003, are included in income taxes. Components of income tax expense (benefit) are as follows (in thousands):

	Year Ended December 31,		
	2004	**2003**	**2002**
Current:			
Federal	$ 2,089	$ 1,516	$ 310
State	552	431	45
	2,641	1,947	355
Deferred:			
Federal	–	550	(1,269)
State	–	80	(180)
	–	630	(1,449)
Income tax expense (benefit)	$ 2,641	$ 2,577	$ (1,094)

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

	Year Ended December 31,		
	2004	**2003**	**2002**
Income taxes at statutory rate	$ 27,742	$ 17,668	$ 11,792
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(25,409)	(15,855)	(12,606)
Increase/(decrease) resulting from:			
Depletion	–	–	(114)
State taxes, net of federal income tax benefit	333	313	(136)
Deferred tax assets retained by ARH Warrior Holdings	–	413	–
Other	(25)	38	(30)
Income tax expense (benefit)	$ 2,641	$ 2,577	$ (1,094)

11. 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,		
	2004	2003	2002
Net income	$ 76,621	$ 47,902	$ 34,785
Adjustments:			
Managing General Partner's incentive distributions	(1,828)	–	–
General Partners' 2% equity ownership	(1,496)	(972)	(726)
Portion applicable to Warrior loss prior to its acquisition on February 14, 2003	–	666	1,504
Limited partners' interest in net income	73,297	47,596	35,563
Weighted average limited partner units - basic	17,941	17,581	15,405
Basic net income per limited partner unit	$ 4.09	$ 2.71	$ 2.31
Weighted average limited partner units—basic	17,941	17,581	15,405
Units contingently issuable:			
Restricted units for Long-Term Incentive Plan	434	527	390
Directors' compensation units deferred	16	16	13
Supplemental Executive Retirement Plan	46	39	35
Weighted average limited partner units, assuming dilutive effect of restricted units	18,437	18,163	15,843
Diluted net income per limited partner unit	$ 3.98	$ 2.62	$ 2.24

Partnership's net income is allocated to the general partners and limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions (Note 9), if any, to the Partnership's Managing GP, the holder of the incentive distribution rights pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. Warrior Coal's loss prior to its acquisition on February 14, 2003 was allocated to the general partners.

The Managing GP is entitled to receive incentive distributions if the amount the Partnership distributes with respect to any quarter exceeds levels specified in the Partnership Agreement. Under the quarterly incentive distribution provisions of the Partnership Agreement, generally, the Managing GP is entitled to receive 15% of the amount the Partnership distributes in excess of $0.55 per unit, 25% of the amount the Partnership distributes in excess of $0.625 per unit and 50% of the amount the Partnership distributes in excess of $0.75 per unit.

12. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans — The Partnership's employees currently participate in a defined contribution profit sharing and savings plan sponsored by the Partnership. 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 matching contributions based on a percent of an employee's eligible compensation and for certain subsidiaries makes an additional nonmatching contribution also based on an employee's eligible 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 $3,267,000, $2,975,000 and $2,959,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

Defined Benefit Plans — Certain employees at the mining operations participate in a defined benefit plan (the "Pension Plan") sponsored by the Partnership. 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, 2004 and 2003 and the funded status of the Pension Plan reconciled with amounts reported in the Partnership's consolidated financial statements at December 31, 2004 and 2003, respectively (dollars in thousands):

	2004	2003
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 22,948	$ 18,077
Service cost	2,821	2,502
Interest cost	1,427	1,215
Actuarial loss	2,180	1,367
Benefits paid	(270)	(213)
Benefit obligation at end of year	29,106	22,948
Change in plan assets:		
Fair value of plan assets at beginning of year	21,185	12,432
Employer contribution	–	5,397
Actual return on plan assets	2,392	3,569
Benefits paid	(270)	(213)
Fair value of plan assets at end of year	23,307	21,185
Funded status	(5,799)	(1,763)
Unrecognized prior service cost	90	139
Unrecognized actuarial loss	5,122	3,789
Net amount recognized	$ (587)	$ 2,165
Amounts recognized in statement of financial position:		
Accrued benefit liability	$ (5,799)	$ (1,763)
Intangible asset	90	139
Accumulated other comprehensive income	5,122	3,789
Net amount recognized	$ (587)	$ 2,165
Weighted-average assumptions as of December 31:		
Discount rate	5.75%	6.25%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31:		
Discount rate	6.25%	6.75%
Expected return on plan assets	8.00%	8.00%
Weighted-average asset allocations as of December 31:		
Equity securities	88%	86%
Fixed income securities	11%	13%
Cash and cash equivalents	1%	1%
	100%	100%

	2004	2003	2002
Components of net periodic benefit cost:			
Service cost	$ 2,821	$ 2,502	$ 2,249
Interest cost	1,427	1,215	952
Expected return on plan assets	(1,686)	(1,115)	(1,050)
Prior service cost	48	48	48
Net loss	141	399	–
Net periodic benefit cost	$ 2,751	$ 3,049	$ 2,199
Effect on minimum pension liability	$ (1,333)	$ (1,486)	$ 4,461

Estimated future benefit payments as of December 31, 2004 are as follows (in thousands):

Year Ending December 31,	
2005	$ 460
2006	634
2007	806
2008	998
2009	1,219
2010-2014	10,322
	$ 14,439

The actuarial loss component of the change in benefit obligations for 2004 and 2003 was primarily attributable to reductions in the discount rate assumptions. The Partnership expects to contribute $2,700,000 to the Pension Plan in 2005.

The Compensation Committee ("Compensation Committee") of the Board of Directors of the Managing GP maintains a Funding and Investment Policy Statement ("Policy Statement") for the Pension Plan. The Policy Statement provides that the assets of the Pension Plan be invested in a diversified mix of domestic equity securities and international equity securities, domestic fixed income securities and cash equivalents with the goal of ensuring that the Pension Plan assets provide sufficient resources to meet or exceed benefit obligations. Investment options, which may be through mutual funds, collective funds, or direct investment in individual stock, bonds or cash equivalent investments, include (a) money market accounts, (b) U.S. Government bonds, (c) corporate bonds, (d) large, mid, and small capitalization stocks, and (e) international stocks. The Policy Statement imposes the following limitations, subject to exceptions authorized by the Compensation Committee under unusual market conditions: the maximum investment in any one stock should not exceed 10% of the total stock portfolio, the maximum investment in any one industry should not exceed 30% of the total stock portfolio, and the average credit quality of the bond portfolio should be at least AA with a maximum amount of non-investment grade debt of 10%. The Policy Statement's current asset allocation guidelines are as follows:

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

The expected long-term rate of return assumption is developed based on input from an independent investment manager, including its review of asset class return, expectations by economists, and an independent actuary. The Partnership's advisors base the projected returns on broad equity and bond indices. The Pension Plan's expected long-term rate of return is based on an asset allocation assumption of 80.0% with equity manager, with an expected long-term rate of return of 10.4%, and 20.0% with fixed income managers, with an expected long-term rate of return of 5.4%. The Pension Plan was established effective January 1, 1997 and the Partnership's initial contribution to the Pension Plan was made in 1998.

13. COMPENSATION PLANS

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 the 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, 2004, the Compensation Committee approved an amendment to the LTIP clarifying that if an award is paid or settled in cash rather than through the delivery of units, then the units granted by such award shall be "reloaded" with respect to which options and restricted units may be granted under the LTIP in the future. In November 2004, the initial LTIP vesting requirements were met when the Partnership satisfied the final conversion financial tests for converting the remaining Subordinated Units into Common Units (Note 9). As a result, LTIP grants of 385,210 units vested in November 2004. The Partnership issued 231,126 Common Units to participants and paid cash to or on behalf of participants for the equivalent of 154,084 units to satisfy personal income tax obligations. During 2004 and 2003 the Compensation Committee approved grants of 102,785 and 141,205 restricted units, respectively, which will vest December 31, 2006 and September 30, 2005, subject to the satisfaction of certain financial tests. As of December 31, 2004, 2,765 restricted units outstanding LTIP grants have been forfeited. During 2004, 2003 and 2002, the Managing GP billed the Partnership approximately $20,320,000, $7,687,000, and $2,338,000, respectively, attributable to the LTIP. Effective January 1, 2005, the Compensation Committee approved additional grants of 57,195 restricted units, which will vest January 1, 2008, subject to the satisfaction of certain financial tests. As of December 31, 2004 there were 127,649 Common Units available for future issuance under the LTIP assuming all grants currently issued and outstanding for calendar year 2003, 2004 and 2005 are settled with common units.

Effective January 1, 1997, the Managing GP adopted a Supplemental Executive Retirement Plan (the "SERP") for certain officers and key employees. The purpose of the SERP is to enhance the Partnership's 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 the Partnership's 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 GP is able to amend or terminate the plan at any time. The Managing GP is entitled to reimbursement by the Partnership for its costs incurred under the SERP. During 2004, 2003 and 2002, the Managing GP billed the Partnership approximately $2,099,000, $626,000, and $64,000, respectively, attributable to the SERP. The increases from 2003 to 2004 and 2002 to 2003 are attributable to the increased market value of the Partnership's Common Units. The total accrued liability associated with the SERP plan as of December 31, 2004 and 2003 was $3,657,000 and $1,558,000, respectively, and is included in the long-term due to affiliates liability in the consolidated balance sheets.

14. 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 discount rates ranging from 4.22% to 6.0%.

On January 1, 2003, the Partnership adopted 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. Since the Partnership has historically adhered to accounting principles similar to SFAS No. 143, this standard had no material effect on the Partnership's consolidated financial statements upon adoption.

Discounting resulted in reducing the accrual for reclamation and mine closing costs by $28,760,000 and $10,332,000 at December 31, 2004 and 2003, respectively. Estimated payments of reclamation and mine closing costs as of December 31, 2004 are as follows (in thousands):

Year Ending December 31	
2005	$ 1,180
2006	2,327
2007	3,779
2008	558
2009	264
Thereafter	54,670
Aggregate undiscounted reclamation and mine closing	62,778
Effect of discounting	28,760
Total reclamation and mine closing costs	34,018
Less current portion	(1,180)
Reclamation and mine closing costs	$ 32,838

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

	Year Ended December 31,		
	2004	**2003**	**2002**
Beginning balance	$ 23,466	$ 23,456	$ 20,518
Accretion expense	1,622	1,341	1,365
Payments	(899)	(1,054)	(865)
Allocation of liability associated with acquisition, mine development and change in assumptions	9,829	(277)	2,438
Ending balance	$ 34,018	$ 23,466	$ 23,456

The reclamation and mine closing cost liability increase of $9,829,000 was primarily attributable to the Lodestar acquisition of $4,129,000 described in Note 3 and the initial land disturbances associated with new operations at Mettiki Coal, LLC and Mettiki Coal (WV), LLC of a combined $2,329,000. The liability also increased as the permitted refuse disposal areas were expanded at several existing operations and a comprehensive study related to water treatment costs was completed. Collectively, these reclamation issues also resulted in the effect of discounting increasing to $28,760,000 from $10,332,000.

15. 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.

Pneumoconiosis ("black lung") benefits liability is calculated using the service cost method. 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 an independent actuary. 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 4.5% and 4.7% at December 31, 2004 and 2003, respectively.

The reconciliation of changes in benefit obligations at December 31, 2004 and 2003 is as follows (in thousands):

	2004	2003
Benefit obligations at beginning of year	$17,633	$16,067
Service cost	1,217	947
Interest cost	1,091	978
Actuarial loss	549	65
Benefits and expenses paid	(155)	(424)
Benefit obligations at end of year	$20,335	$17,633

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 have challenged certain provisions of the revised regulations through litigation, but the regulations were upheld, with some exceptions as to the retroactive application of the regulations. The revised regulations are expected to result in an increase in the incidence and recovery of black lung claims.

16. RELATED PARTY TRANSACTIONS

Administrative Services — 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, but not limited to, management's salaries and related benefits (including the LTIP), 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 $28,536,000, $12,471,000 and $6,559,000 for the years ended December 31, 2004, 2003 and 2002, respectively. The increase from 2003 to 2004 and 2002 to 2003 were primarily attributable to higher accruals for the LTIP, STIP and Supplemental Executive Retirement Plan ("SERP"). The expenses associated with LTIP and SERP were impacted by the market value of the Partnership's Common Units, which had a closing market price of $74.00, $34.38 and $24.22 at December 31, 2004, 2003 and 2002, respectively. The amounts billed by the managing GP include $24,242,000, $9,319,000 and $3,308,000 for the years ended December 31, 2004, 2003 and 2002, respectively, for the LTIP, STIP and SERP.

SGP Land — Webster County Coal, LLC ("Webster County Coal") has a mineral lease and sublease with SGP Land requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid royalties of $4,611,000, $3,460,000 and $2,700,000 for the years ended December 31, 2004, 2003 and 2002, respectively. Webster County Coal has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $805,000 as of December 31, 2004.

Warrior Coal has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior Coal has paid and will continue to pay in arrears an annual minimum royalty obligation of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments have been paid. The annual minimum royalty periods are from October 1 through the end of the following September 30, expiring September 30, 2007. Warrior Coal paid royalties of $2,561,000, $2,453,000 and $2,127,000 for the years ended December 31, 2004, 2003 and 2002, respectively. Warrior Coal has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $636,000 as of December 31, 2004.

Under the terms of the mineral lease and sublease agreements described above, Webster County Coal and Warrior Coal also reimburse SGP Land for SGP Land's base lease obligations. The Partnership reimbursed SGP Land $5,428,000, $4,395,000 and $3,922,000 for the years ended December 31, 2004, 2003 and 2002, respectively, for the base lease obligations. Webster County Coal and Warrior Coal have recouped as earned royalties all advance minimum royalty payments made in accordance with these terms except for $216,000 as of December 31, 2004.

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 paid and will continue to 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 $479,000 and $568,000 for the years ended December 31, 2003 and 2002, respectively. The 2004 annual minimum royalty obligation of $300,000 was paid in January 2005. MC Mining has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2004.

The Partnership also has an option to lease and/or sublease certain reserves from SGP Land, which reserves are contiguous to the Partnership's Hopkins County Coal, LLC mining complex. Under the terms of the option to lease and sublease, the Partnership paid option fees of $1,368,000 and $684,000 during the years ended December 31, 2004 and 2002, respectively. The 2003 option fee of $684,000 was paid in January 2004 and is included in the due to affiliates balance as of December 31, 2003. The anticipated annual minimum royalty obligation is $684,000, payable in advance through 2009.

Special GP — 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 2011. Lease expense incurred for each of the three years in the period ended December 31, 2004 was $2,595,000.

The Partnership previously entered into and has maintained agreements with two banks to provide letters of credit in an aggregate amount of $25.0 million (Note 8). At December 31, 2004, the Partnership had $22.2 million in outstanding letters of credit. The Special GP guarantees these letters of credit. Historically, the Partnership has compensated the Special GP for a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. During 2003 the Special GP agreed to waive the guarantee fee in exchange for a parent guarantee from the Intermediate Partnership and Alliance Coal, LLC on the mineral lease and sublease with Webster County Coal and Warrior Coal described above. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FIN No. 45 and does not impact the consolidated financial statements. The Partnership paid approximately $31,300 and $48,200 in guarantee fees to the Special GP for the years ended December 31, 2003 and 2002, respectively.

17. COMMITMENTS AND CONTINGENCIES

Commitments — The Partnership leases buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. The Partnership also has a noncancelable lease with the Special GP (Note 16). Future minimum lease payments under operating leases are as follows (in thousands):

Year Ending December 31,	Affiliate	Others	Total
2005	$ 2,595	$ 2,071	$ 4,666
2006	2,595	1,650	4,245
2007	2,595	819	3,414
2008	2,595	264	2,859
2009	2,595	13	2,608
Thereafter	2,810	–	2,810
	$ 15,785	$ 4,817	$ 20,602

Lease expense under all operating leases was $6,112,000, $5,490,000 and $4,707,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

In October 2002, the Partnership entered into a master equipment lease. The Partnership's credit facilities limit the amount of total operating lease obligations to $10 million payable in any period of 12 consecutive months. This master equipment lease is subject to this limitation on lease obligations. The Partnership entered into nine operating leases during 2003 under the master equipment lease with lease terms ranging from three to six years. The Partnership did not enter into any new equipment leases under the master equipment lease during 2004.

Contractual Commitments — In connection with planned capital projects, the Partnership had contractual commitments of approximately $8.4 million at December 31, 2004.

General Litigation — The Partnership is involved in various lawsuits, claims and regulatory proceedings, 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. Although the ultimate outcome of these matters cannot be predicted with certainty, in the opinion of management, the outcome of these matters, to the extent not previously provided for or covered under insurance, are not expected to have a material adverse effect on the Partnership's business, financial position or results of operations. Nonetheless, these matters or estimates that are based on current facts and circumstances, if resolved in a manner different from the basis on which management has formed its opinion, could have a material adverse effect on the Partnership's financial position or results of operations.

Other — During September 2004, the Partnership completed its annual property and casualty insurance renewal. As a result, the Partnership and its affiliates retained a 10.0% participating interest along with its insurance carriers in the commercial property program. The aggregate maximum limit in the commercial property program is $75 million per occurrence of which the Partnership would be responsible for a maximum amount of $7.5 million for each occurrence, excluding a $3.5 million deductible.

Mettiki Coal (WV), LLC has proposed a long-wall underground mine extension (the "E-Mine") to be located primarily in Tucker County, West Virginia, which will eventually replace the Partnership's Mettiki Coal, LLC's existing long-wall mine, D-Mine located in Garrett County, Maryland. The proposed mine, which will be either a long-wall or continuous mining operation, is approximately 10 miles from Mettiki Coal. In order to proceed with the development of the E-Mine, Mettiki Coal (WV) filed two separate permit applications with the West Virginia Department of Environmental Protection ("WVDEP") concerning on-site disposal of scalp rock and underground mining, each requiring an associated water discharge permit. The Partnership was notified on April 16, May 13, May 26, and June 7, 2004, that WVDEP has issued the permits for on-site disposal of scalp rock, underground mining, water discharge related to the operation of the scalp rock disposal facility, and water discharge related to the operation of the underground mine, respectively.

The appeal periods for the scalp rock permit and the two water discharge permits related to the operation of the scalp rock disposal facility and underground mine have lapsed without any appeal being filed. Two appeals of the underground mining permit were filed on June 11 and 16, 2004, respectively. The West Virginia Surface Mine Board ("SMB") consolidated the appeals and held an administrative initial hearing on October 19 and 20, 2004, December 7 and 8, 2004 and January 11 and February 7, 2005.

On March 8, 2005, the SMB issued a Final Order concluding consideration of the consolidated appeals without a decision, which Final Order held that the SMB was unable to take any action relating to the issuance of the underground permit by WVDEP because its vote did not obtain the concurrence of at least four SMB members as required by West Virginia law. Consequently, the ultimate decision by the WVDEP to issue the underground permit was affirmed by operation of West Virginia law. In the Final Order, however, the SMB voted unanimously to require Mettiki Coal (WV) to increase the amount of a surety bond that serves as security for a portion of the reclamation plan approved by WVDEP as part of the underground permit. On March 8, 2005, Mettiki Coal (WV) filed an appeal of the Final Order with the Circuit Court of Tucker County, West Virginia, on the ground that the SMB was wrong in ordering Mettiki Coal (WV) to increase the surety bond for part of the reclamation plan approved by WVDEP when the SMB, as a result of not obtaining the concurrence of at least four members, failed to affirm the decision by WVDEP to issue a final order approving the underground permit issued by WVDEP on May 13, 2004. On March 10, 2005 the West Virginia Rivers Coalition, the West Virginia Highlands Conservancy, and Trout Unlimited – West Virginia Council filed an appeal of the SMB's final order with the Circuit Court of Kanawha County, West Virginia. The appeal requests that the Circuit Court (a) grant a stay of the WVDEP's approval of the E-Mine permit pending a decision by the Circuit Court, (b) set a briefing schedule and oral argument of the appeal and (c) reverse and vacate the WVDEP's approval of the permit. Management believes the WVDEP's approval of the permit application will be ultimately upheld by the applicable Circuit Court in West Virginia.

On October 12, 2004, Pontiki Coal, LLC ("Pontiki") was served with a complaint from ICG alleging a breach of contract and seeking declaratory relief to determine the parties' rights under a coal sales agreement between Horizon Natural Resource Sales Company ("Horizon Sales"), as buyer, and Pontiki Coal Corporation, as seller, dated October 3, 1998, as amended on February 28, 2001 (the "Agreement"). ICG has represented that it acquired the rights and assumed the liabilities of the Agreement effective September 30, 2004 as part of an asset sale approved by the U.S. bankruptcy court supervising the bankruptcy proceedings of Horizon Sales and its affiliates. Pontiki is the successor-in-interest of Pontiki Coal Corporation as a result of a merger completed on August 4, 1999.

The complaint alleges that from January 2004 to August 2004, Pontiki failed to deliver a total of 138,111 tons of coal resulting in an alleged loss of profits for ICG of $4.1 million. The Partnership has been unable to confirm ICG's calculation of the alleged shortfall of coal deliveries. The Partnership is aware that certain deliveries under the Agreement have not been made during 2004 for reasons including, but not limited to, force majeure events at Pontiki and ICG's failure to provide transportation services for the delivery of coal as required under the Agreement. This litigation is in the preliminary stage and the Partnership does not believe that it is probable that a loss has been incurred. The Partnership also does not believe that this litigation has merit and intends to contest the litigation vigorously. The Partnership is unable, however, to predict the outcome of the litigation or reasonably estimate a range of possible loss given the current status of the litigation.

At certain of the Partnership's operations, property tax assessments for several years are under audit by the related tax authorities. The Partnership believes that it has recorded adequate liabilities based on reasonable estimates of any property tax assessments that may be ultimately assessed as a result of these audits.

18. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

The Partnership has significant long-term coal supply agreements, some of which contain prospective price adjustment provisions designed to reflect changes in market conditions, labor and other production costs and, when the coal is sold other than FOB the mine, changes in transportation rates. Total revenues to major customers, including transportation revenues (Note 2), which exceed ten percent of total revenues (Customer C comprised less than nine percent of total revenues in 2004) are as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Customer A	$ 124,847	$ 116,750	$ 113,094
Customer B	89,887	78,724	72,224
Customer C	56,658	52,561	69,933

Trade accounts receivable from these customers totaled approximately $24.3 million at December 31, 2004. 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. The Partnership received $114,000 in 2004 for its claim against Enron and recognized as a recovery in 2004. 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 and C expire in 2007, 2006 and 2010, respectively.

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, 2004 (1)	June 30, 2004	September 30, 2004 (2)	December 31, 2004 (3)
Revenues	$ 157,824	$ 162,546	$ 158,261	$ 174,658
Operating income	22,493	27,180	29,337	14,231
Income before income taxes	18,964	23,589	25,867	10,842
Net income	18,225	22,861	25,321	10,214
Basic net income per limited partner unit	$ 1.00	$ 1.22	$ 1.37	$ 0.51
Diluted net income per limited partner unit	$ 0.97	$ 1.18	$ 1.33	$ 0.49
Weighted average number of units outstanding – basic	17,903,793	17,903,793	17,903,793	18,051,606
Weighted average number of units outstanding – diluted	18,439,099	18,438,551	18,438,758	18,437,164

	Quarter Ended			
	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
Revenues	$ 124,925	$ 133,471	$ 141,799	$ 142,552
Operating income	18,057	12,781	15,210	19,038
Income before income taxes	14,083	9,248	11,466	15,682
Net income	13,128	8,528	10,803	15,443
Basic net income per limited partner unit	$ 0.81	$ 0.47	$ 0.59	$ 0.85
Diluted net income per limited partner unit	$ 0.79	$ 0.45	$ 0.57	$ 0.82
Weighted average number of units outstanding - basic	16,593,609	17,903,793	17,903,793	17,903,793
Weighted average number of units outstanding - diluted	17,176,824	18,485,741	18,487,787	18,486,098

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

(1) The Partnership's March 31, 2004 quarterly results were impacted by extra expenses associated with extinguishing the Dotiki Fire Incident, in addition the Partnership recognized as an offset to operating expenses $2.9 million representing estimated insurance recoveries for expenses incurred as a result of the Dotiki Fire Incident (Note 4).

(2) The Partnership's September 30, 2004 quarterly results were impacted by an offset to operating expenses of $2.8 million due to the final settlement of insurance claims attributable to the Dotiki Fire Settlement and a net gain from insurance settlement of approximately $15.2 million attributable to the final settlement of insurance claims attributable to the Dotiki Fire Incident (Note 4).

(3) The Partnership's December 31, 2004 quarterly results were impacted by an accrual of $4.1 million reflecting the Partnership's initial estimate of certain minimum costs attributable to the MC Mining Fire Incident that are not reimbursable under the Partnership's insurance policies (Note 4).

(4) The Partnership's December 31, 2003 quarterly results were impacted by a contractual modification that resulted in a $2.0 million favorable pricing adjustment associated with coal feedstock sales to Synfuel Solutions Operating LLC for shipments made primarily in 2003 but prior to the fourth quarter of 2003. Additionally, operating expenses decreased due to the reversal of an expense accrual of $1.2 million established in 1998. The expense accrual was established in conjunction with the idling of Pontiki in 1998 that created an expectation of a probable increase in workers' compensation costs associated with the terminated workforce. The expected anticipated increase in workers' compensation claims did not emerge and, with limited exceptions, the statute of limitations expired in December 2003 for the filing or reopening of workers' compensation claims associated with the employee terminations.

20. SUBSEQUENT EVENT

On January 1, 2005 the Partnership acquired 100% of the limited liability company member interest of Tunnel Ridge, LLC from Alliance Resource Holdings, Inc., a company owned by management of the Partnership (Note 3).

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SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

	Balance At Beginning Of year	Additions Charged To Income	Deductions	Balance At End Of Year
		(in thousands)		
2004				
Allowance for doubtful accounts	$ 763	$ –	$ 763	$ –
2003				
Allowance for doubtful accounts	$ 763	$ –	$ –	$ 763
2002				
Allowance for doubtful accounts	$ 763	$ –	$ –	$ 763

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. In 2004, the Partnership collected approximately $114,000 from the sale to a third-party of a bankruptcy claim relating to this receivable to a third-party. The remaining balance of $649,000 was written-off.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. The Partnership maintains controls and procedures designed to ensure that it is able to collect the information it is required to disclose in the reports it files with the SEC, and to process, summarize and disclose this information within the time periods specified in the rules of the SEC. An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based on an evaluation of the Partnership's disclosure controls and procedures as of the end of the period covered by this report conducted by the Partnership's management, with the participation of our Chief Executive and Chief Financial Officers, our Chief Executive and Chief Financial Officers believe that these controls and procedures are effective to ensure that the Partnership is able to collect, process and disclose the information it is required to disclose in the reports it files with the SEC within the required time periods, and there were no material changes in internal control over financial reporting occurring in the fourth quarter of 2004.

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

Management's Annual Report on Internal Control over Financial Reporting. Management of the Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. The Partnership's internal control over financial reporting is designed to provide reasonable assurance to the Partnership's management and board of directors regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the Partnership's assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are complemented by a staff of component business process owners and an internal auditor supported by competent and qualified external resources used to assist in testing the operating effectiveness of the Partnership's internal control over financial reporting. Management believes that the design and operations of our internal controls over financial reporting at December 31, 2004 are effective and provide reasonable assurance that the books and records accurately reflect the transactions of the Partnership.

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework.* Based on our assessment, we believe that, as of December 31, 2004, the Partnership's internal control over financial reporting is effective based on those criteria, and we believe that we have no material internal control weaknesses in our financial reporting process.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, has been audited by Deloitte & Touche, LLP, the independent registered public accounting firm, which also audited the Partnership's consolidated financial statements. Deloitte & Touche's attestation report on management's assessment of the Partnership's internal control over financial reporting appears below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that Alliance Resource Partners, L.P. and subsidiaries (the "Partnership") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Partnership's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Partnership maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2004 and 2003 and the related consolidated statements of income, cash flows and Partners' capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2004 and the financial statement schedule listed in the Index at Item 15 of the Partnership, and our report dated March 15, 2005 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Tulsa, Oklahoma
March 15, 2005

ITEM 9B. OTHER

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, PROMOTERS AND CONTROL PERSONS 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 our managing general partner. Executive officers and directors are elected until death, resignation, retirement, disqualification, or removal.

Name	Age	Position With our Managing General Partner
Joseph W. Craft III	54	President, Chief Executive Officer and Director
Robert G. Sachse	56	Executive Vice President and Vice Chairman of the Board
Thomas L. Pearson	51	Senior Vice President – Law and Administration, General Counsel and Secretary
Charles R. Wesley	50	Senior Vice President – Operations
Brian L. Cantrell	45	Senior Vice President – Chief Financial Officer
Gary J. Rathburn	54	Senior Vice President – Marketing
Michael J. Hall	60	Director and Member of the Audit* and Conflicts Committees
John J. MacWilliams	49	Director
Preston R. Miller, Jr.	56	Director and Member of the Compensation* Committee
John P. Neafsey	65	Chairman of the Board and Member of Audit, Compensation and Conflicts Committees
John H. Robinson	54	Director and Member of Audit, Compensation and Conflicts* Committees

*Indicates Chairman of Committee

Joseph W. Craft III has been President, Chief Executive Officer and a Director since August 1996 and has indirect majority ownership of our managing general partner. Previously Mr. Craft served as President of MAPCO Coal Inc. since 1986. During that period, he also was Senior Vice President of MAPCO Inc. and had been previously that company's General Counsel and Chief Financial Officer. Before joining MAPCO, Mr. Craft was an attorney at Falcon Coal Corporation and Diamond Shamrock Coal Corporation. He is 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 has been Executive Vice President and Vice Chairman since August 2000. Prior to his current position, Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO merged with The Williams Companies. Following the merger, Mr. Sachse had a two year non-compete consulting agreement with The Williams Companies. Mr. Sachse held various positions while with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree in Business Administration from Trinity University and a Juris Doctor degree from the University of Tulsa.

Thomas L. Pearson has been Senior Vice President – Law and Administration, General Counsel and Secretary since August 1996. Mr. Pearson previously was Assistant General Counsel of MAPCO Inc., and served as General Counsel and Secretary of MAPCO Coal Inc. from 1989 to 1996. Before joining the company, he was General Counsel and Secretary of McLouth Steel Products Corporation, Corporate Counsel for Midland-Ross Corporation, and an attorney for Arter & Hadden, a law firm in Cleveland, Ohio. Mr. Pearson's current and past business, charitable and education involvement includes Trustee of the Energy and Mineral Law Foundation, Vice Chairman, Legal Affairs Committee, National Mining Association, and Member, Dean's Committee, The University of Iowa College of Law. 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.

Charles R. Wesley has been Senior Vice President – Operations since August 1996. He joined the company in 1974 when he began working for Webster County Coal Corporation as an engineering co-op student. In 1992, Mr. Wesley was named Vice President – Operations for Mettiki Coal Corporation. He has served the industry as past President of the West Kentucky Mining Institute and National Mine Rescue Association Post 11, and he has 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.

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

Gary J. Rathburn has been Senior Vice President – Marketing since August 1996. He joined MAPCO Coal Inc. as Manager of Brokerage Coals in 1980. Since that time, he has managed all phases of the marketing group involving transportation and distribution, international sales and the brokering of coal. Prior to joining the company, Mr. Rathburn was employed by Eastern Associated Coal Corporation in its International Sales and Brokerage groups. Active in many industry-related groups, he 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.

Michael J. Hall became a Director in March 2003. Mr. Hall was Vice President – Finance and Chief Financial Officer, Secretary and Treasurer of Matrix Service Company (Matrix) from September, 1998 until he retired in May, 2004. He continues to serve on Matrix's Board of Directors, a position he assumed when he joined Matrix in 1998. Matrix is a company which provides general industrial construction and repair and maintenance services principally to the petroleum, petrochemical, power, bulk storage terminal, pipeline and industrial gas industries. Mr. Hall was responsible for all financial and administrative functions including accounting, financial reporting, auditing, finance, budgeting, tax, risk management, investor relations, human resources and information technology. Prior to working for Matrix, Mr. Hall was Vice President and Chief Financial Officer of Pexco Holdings, Inc., Vice President – Finance and Chief Financial Officer for Worldwide Sports & Recreation, Inc. an affiliated company of Pexco and worked for T.D. Williamson, Inc., as Senior Vice President, Chief Financial and Administrative Officer, and Director of Operations – Europe, Africa and Middle East Region. Mr. Hall holds a Bachelor of Science degree in Accounting from Boston College and a Master of Business Administration from Stanford University. Mr. Hall is chairman of the audit committee and a member of the conflicts committee.

John J. MacWilliams, is a Partner of The Tremont Group, LLC, a private equity investment firm founded in January 2003, located in Newton, MA., which has specialized expertise in the energy industry. Mr. MacWilliams is also a General Partner of The Beacon Group, LP, which he joined in 1993, and has served as a Director since June 1996. As part of the Beacon Group, he co-manages two private equity funds focusing on the energy industry. Mr. MacWilliams' previous positions include serving as a General Partner of JP Morgan Partners, Executive Director of Goldman Sachs International in London, Vice President for Goldman Sachs & Co.'s Investment Banking Division in New York, and as an attorney at Davis Polk & Wardwell in New York. He also is a Director of Compagnie 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., is a Partner of The Tremont Group, LLC, a private equity investment firm founded in January 2003, located in Newton, MA., which has a specialized expertise in the energy industry. Mr. Miller is a General Partner of The Beacon Group, LP that he joined in 1993 and has served as a Director since June 1996. As a part of The Beacon Group, he co-manages two private equity funds focusing on the energy industry. Mr. Miller's previous positions include serving as a General Partner of JP Morgan Partners from June 2000 through December 2002, and was with Goldman Sachs & Co.'s from January 1979 through January 1993, most recently as Vice President in the Structured Finance Group in New York City where he had global responsibility for coverage of the independent power industry, asset-backed power generation, and oil and gas financing. He also has a background in credit analysis, and was head of the revenue bond rating group at Standard & Poor's Corp. Mr. Miller holds a Bachelor of Arts degree from Yale University and a Master of Public Administration degree from Harvard University. Mr. Miller is the chairman of the compensation committee.

John P. Neafsey has served as Chairman since June 1996. Mr. Neafsey is President of JN Associates, an investment consulting firm formed in 1993. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and a Director since its founding in 1983. Positions that Mr. Neafsey held during a 23-year career at The Sun Company include Director, Executive Vice President responsible for Canadian operations, Sun Coal Company and Helios Capital Corporation; Chief Financial Officer; and other executive positions with numerous subsidiary companies. He is or has been active in a number of organizations, including the following: Director for The West Pharmaceutical Services Company and Chairman of both Constar, Inc. and NES Rentals, Inc., 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. Mr. Neafsey is a Member of the audit, conflicts and compensation committees.

John H. Robinson became a Director in December 1999. Mr. Robinson is Vice Chairman of Olsson Associates, an engineering consultancy. From 2003 to 2004, he was Chairman of EPC Global, Ltd., an engineering staffing company, and President of Metilinix, Inc., a system optimization software company. From 2000 to 2002, he was Executive Director of Amey plc, a British business process outsourcing company. Mr. Robinson served as Vice Chairman of Black & Veatch from 1998 to 2000. He began his career at Black & Veatch in 1973 and was a General Partner and Managing Partner prior to becoming Vice Chairman when the firm incorporated. Mr. Robinson is a Director of Coeur d'Alene Mining Corporation. Mr. Robinson holds Bachelor and Master of Science degrees in Engineering from the University of Kansas and is a graduate of the Owner-President-Management Program at the Harvard Business School. He is chairman of the conflicts committee and a member of the audit and compensation committees.

Audit Committee

The audit committee is comprised of three non-employee members of the board of directors (currently, Mr. Hall, Mr. Neafsey and Mr. Robinson). After reviewing the qualifications of the current members of the audit committee, and any relationships they may have with us that might affect their independence, the board of directors has determined that all current audit committee members are “independent” as that concept is defined in Section 10A of the Exchange Act, all current audit committee members are “independent” as that concept is defined in the applicable rules of the NASDAQ, all current audit committee members are financially literate, and Mr. Hall and Mr. Neafsey qualify as audit committee financial experts under the applicable rules promulgated pursuant to the Exchange Act.

Report of the Audit Committee. The audit committee of Alliance Resource Management GP, LLC, oversees our Partnership's financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The audit committee has the responsibility for the appointment, compensation and oversight of the work of our independent registered public accounting firm and will assist the board of directors by conducting its own review of our:

- filings with the Securities and Exchange Commission (the "SEC") and the Securities Act of 1933 and the Securities Exchange Act of 1934 (the "Exchange Act") (i.e., Forms 10-K, 10-Q, and 8-K);

- press releases and other communications by the Partnership to the public concerning earnings, financial condition and results of operations, including changes in distribution policies or practices affecting the holders of Partnership units;

- systems of internal controls regarding finance and accounting that management and the board of directors have established; and

- auditing, accounting and financial reporting processes generally.

In fulfilling its oversight and other responsibilities, the audit committee either met or took action in the form of written consents eleven times during 2004. The audit committee's activities included, but were not limited to, (a) the selection of the independent registered public accounting firm, (b) meeting periodically in executive session with the independent registered public accounting firm, (c) the review of the Quarterly Reports on Form 10-Q for the three months ended March 31, June 30, and September 30, 2004, (d) performing a self-assessment of the committee itself and (e) reviewing and amending the audit committee charter. Based on the results of the self-assessment, the audit committee believes that it satisfied the requirements of its charter. The audit committee also reviewed and discussed with management and the independent registered public accounting firm this Annual Report on Form 10-K, including the audited financial statements.

The Partnership's independent registered public accounting firm, Deloitte & Touche, LLP, are responsible for expressing an opinion on the conformity of the audited financial statements with generally accepted accounting principles. The audit committee reviewed with Deloitte & Touche, LLP their judgment as to the quality, not just the acceptability, of the Partnership's accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards.

The audit committee discussed with Deloitte & Touche, LLP the matters required to be discussed by SAS 61 (Codification of Statement on Auditing Standards, AU § 380), as may be modified or supplemented. The committee received written disclosures and the letter from Deloitte & Touche, LLP required by Independence Standards Board No. 1., Independence Discussions with Audit Committees, as may be modified or supplemented, and has discussed with Deloitte & Touche, LLP its independence from management and the Partnership.

Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2004 for filing with the SEC.

Members of the Audit Committee:

Michael J. Hall, Chairman

John P. Neafsey

John H. Robinson

Code of Ethics

We have adopted a Code of Ethics with which our chief executive officer and our senior financial officers (including our principal financial officer, and our principal accounting officer or controller), are expected to comply. The Code of Ethics is publicly available on our website under Investors Relations at www.arlp.com and is available in print to any unitholder who requests it. If any substantive amendments are made to the Code of Ethics or if there is a grant of a waiver, including any implicit waiver, from a provision of the code to our chief executive officer, chief financial officer, chief accounting officer or controller, we will disclose the nature of such amendment or waiver on our website or in a report on Form 8-K.

Communications with the Board

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the 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 they file. Based solely upon a review of the copies of the forms furnished to us, or written representations from certain reporting persons, we believe that during 2004 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a) other than Mr. Sachse who did not timely file a Form 4 related to his purchase of 104 units on October 4, 2004, but has since filed a Form 4 with respect to this transaction.

Reimbursement of Expenses of our Managing General Partner and its Affiliates

Our managing general partner does not receive any management fee or other compensation in connection with its management of us. 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 our managing general partner will determine the expenses that are allocable to us in any reasonable manner determined by our managing general partner in its sole discretion.

ITEM 11. EXECUTIVE COMPENSATION

Executive Compensation

The following table sets forth certain compensation information for the chief executive officer and each of the four other most highly compensated executive officers of our managing general partner in excess of $100,000 in 2004, 2003 and 2002. We reimburse our managing general partner and its affiliates for expenses incurred on our behalf, including the cost of officer compensation allocable to us.

Summary Compensation Table

Name and Principal Position	Year	Annual Compensation: Salary	Bonus (1)	Other Annual Compensation (2)	Long-Term Compensation Payouts (3)	All Other Compensation (4)
Joseph W. Craft III,	2004	$341,267	375,000	$3,521	$ 8,286,600	$79,479
President, Chief Executive Officer	2003	334,828	387,000	3,400	–	62,694
and Director	2002	328,955	227,000	1,075	–	52,171
Thomas L. Pearson,	2004	203,520	225,000	–	1,473,746	39,435
Senior Vice President-Law and	2003	199,680	166,000	–	–	31,481
Administration, General Counsel and Secretary	2002	196,178	83,000	1,750	–	32,631
Charles R. Wesley,	2004	229,612	300,000	825	1,657,320	75,320
Senior Vice President-Operations	2003	215,665	234,500	–	–	37,115
	2002	211,504	130,000	–	–	33,001
Gary J. Rathburn,	2004	177,020	222,000	–	1,508,939	38,790
Senior Vice President-Marketing	2003	173,680	171,000	–	–	30,602
	2002	170,634	90,000	2,285	–	29,884
Thomas M. Wynne	2004	164,631	222,000	–	1,154,205	45,377
Vice President-Operations	2003	153,600	150,000	–	–	17,448
	2002	144,462	60,000	–	–	16,102

(1) Amounts awarded under the Short-Term Incentive Plan. Please see "Short-Term Incentive Plan" below.
(2) Amounts reimbursed for income tax preparation and financial planning services.
(3) Amounts represent the market value of the LTIP grants for the years 2002, 2001 and 2000 that vested in November 2004.
(4) Amounts represent (a) our managing general partner's matching contributions to its profit sharing and savings plan, (b) our managing general partner's contribution to its Supplemental Executive Retirement Plan (SERP), and (c) the amounts for Mr. Wesley and Mr. Wynne include a non Short-Term Incentive Plan bonus approved by the compensation committee.

Compensation of Directors

Under our managing general partner's Directors' Compensation Program (Directors' Plan) each non-employee director was paid an annual retainer of $22,500 during 2004. 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 is eligible to participate in a deferred compensation plan that is administered by the compensation committee. Prior to the beginning of each plan year, each non-employee director may elect to defer all or a portion of his compensation until he ceases to be a member of the board of directors. A new election must be made for each plan year. For compensation deferred by a director, a notional account is established and credited with "phantom" units equal to the number of common units deferred. In addition, when distributions are made with respect to common units, the notional account is credited with "phantom" distributions with respect to phantom units that are equal in amount to the distributions made with respect to common units. The board of directors may change or terminate the deferred compensation plan at any time; provided, however, that accrued benefits under the deferred benefit plan cannot be impaired.

In addition, each non-employee director is entitled to participate in the Long-Term Incentive Plan. Under the Long-Term Incentive Plan such directors receive annual grants of restricted units, which vest in accordance with the procedures described below. Please see "Long-Term Incentive Plan" below.

Mr. Sachse has a consulting agreement with our managing general partner with an indefinite term, subject to termination by either party upon receipt of ninety-day advance written notice of termination. The consulting agreement provides that Mr. Sachse will serve as Executive Vice President of our managing general partner and devote his services on a part-time basis. In addition to compensation received under the Directors' Plan described above and Long-Term Incentive Plan described below, 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 of $7,500, payable in common units of the Partnership. Copies of Mr. Sachse's original consulting agreement and the letter agreement extending the term of the original agreement are exhibits hereto.

Employment Agreements

The executive officers of our 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 our managing general partner on the other. We reimburse our 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 Mr. Craft, Mr. Pearson, Mr. Wesley and Mr. Rathburn is an exhibit hereto.

Each of the form of employment agreements had an initial term that expired on December 31, 2002, but automatically extend for successive one-year terms unless either party gives 12 months prior notice to the other party. The form of employment agreements provide for a base salary, subject to review annually, of $334,828, $199,680, $225,280 and $173,680 for Mr. Craft, Mr. Pearson, Mr. Wesley and Mr. Rathburn, respectively. Differences between these base salaries as compared to the base salaries reported in the summary compensation table are attributable to the number of weekly pay periods in a calendar year. 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, Wesley and Rathburn, following termination of employment, except in the case of a change of control of our 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, 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 our 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 our 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 our managing general partner provides for its employees.

Long-Term Incentive Plan

Effective January 1, 2000, our managing general partner adopted the Long-Term Incentive Plan (LTIP) for certain employees and directors of our 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 our managing general partner's board of directors. Annual grant levels for designated participants are recommended by the president and chief executive officer of our managing general partner, subject to the review and approval of the compensation committee. We will reimburse our managing general partner for all costs incurred pursuant to the programs described below. Grants are made of either 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 our 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 our managing general partner, or any combination of the foregoing. Our 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, 2004, the compensation committee approved an amendment to the LTIP clarifying that if an award is paid or settled in cash rather than through the delivery of units, then the units granted by such award shall be available with respect to which options and restricted units may be granted under the LTIP in the future. A copy of the amendment is an exhibit hereto. During 2004 and 2003 the compensation committee approved grants of 102,785 and 141,205 restricted units, which will vest December 31, 2006 and September 30, 2005 subject to the satisfaction of certain financial tests. As of December 31, 2004, 2,765 outstanding LTIP grants have been forfeited. Effective as of January 1, 2005, the compensation committee approved additional grants of 57,195 restricted units, which vest on January 1, 2008 subject to the satisfaction of certain financial tests. As of March 1, 2005 there were 70,454 common units available for future issuance under the LTIP assuming all grants currently issued and outstanding for calendar years 2003, 2004 and 2005 are settled with common units.

In November 2004, the initial LTIP vesting requirements were met when we satisfied the final conversion financial tests for converting the remaining subordinated units into common units. As a result, LTIP grants for the years 2000, 2001 and 2002 of 385,210 units vested in November 2004. We issued 231,126 common units to participants and paid cash to or on behalf of participants for the equivalent of 154,084 units to satisfy personal income tax obligations.

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.

The issuance of the common units pursuant to the vesting of restricted units under the LTIP 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. The compensation committee, in it 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, in the future, may decide to make unit option grants to employees and directors containing the specific terms as the committee determines. 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.

Our 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. Our 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, our managing general partner may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward its employees. Our managing general partner is reimbursed for all compensation expenses incurred on our behalf.

Long-Term Incentive Plan – Awards in Last Fiscal Year

	Number of Units (1)	**Performance or Other Period Until Maturation or Payout (2)**
Joseph W. Craft III	28,000	36 Months
Thomas L. Pearson	6,300	36 Months
Charles R. Wesley	10,400	36 Months
Gary J. Rathburn	6,400	36 Months
Thomas M. Wynne	4,350	36 Months

(1) Units granted under the LTIP will vest December 31, 2006, subject to certain financial tests.

(2) The number of units granted is not subject to minimum thresholds, targets or maximum payout conditions. However, the vesting of these grants is subject to meeting certain financial tests.

Short-Term Incentive Plan

Our managing general partner maintains a STIP for management and other salaried employees. The STIP is designed to enhance the financial performance by rewarding management and selected salaried employees and those of our 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 chief executive officer of our managing general partner and approved by the compensation committee of its board of directors prior to or during January 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 our managing general partner is able to amend the plan at any time. Our managing general partner is entitled to reimbursement by us for the costs incurred under the STIP.

Supplemental Executive Retirement Plan

Our managing general partner maintains 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. Our managing general partner is able to amend or terminate the plan at any time. Our managing general partner is entitled to reimbursement by us for its costs incurred under the SERP.

Compensation Committee's Report on Executive Compensation

The compensation committee administers the executive compensation programs of our managing general partner and was established to fulfill two purposes: (a) to discharge the board of directors' responsibilities relating to compensation of our managing general partner's directors and executives and (b) to produce an annual report on executive compensation for inclusion in our annual report on Form 10-K. All three members of the compensation committee of the board of directors (currently Mr. Miller, Mr. Neafsey and Mr. Robinson) are "non-employee directors" as defined under the Securities Exchange Act of 1934 and the Internal Revenue Code. The board of directors has assigned to the compensation committee the following functions:

- To review and approve corporate goals and objectives relative to our managing general partner's president and chief executive officer's (CEO) compensation, and evaluate the CEO's performance in light of those goals and objectives and to set the CEO's compensation level based on this evaluation.
- To review and approve corporate goals and objectives relative to our senior executive officers, including our named executive officers' compensation, evaluate our senior executive officers' performance in light of those goals and objectives, and to set the senior executive compensation levels based on this evaluation.
- To make recommendations to the board of directors with respect to incentive compensation plans and equity-based plans, including, without limitation, our managing general partner's short-term incentive plan (STIP), long-term incentive plan (LTIP), and supplemental executive retirement plan (SERP).
- To administer our managing general partner's LTIP and grant restricted units or other awards pursuant to such plan.

For the fiscal year ended December 31, 2004, the compensation committee met on five separate occasions and primarily focused its activities on the primary elements of the total direct compensation program for executive officers; the merits of continuation of the LTIP; the guidelines for the STIP pertaining to eligibility, minimum thresholds, target objectives, target results, target payout groups, the respective percentage targets and the payout formula.

Overall Executive Compensation Program

The goals of our managing general partner's executive compensation program are to align compensation with our managing general partner's business objectives and performance and enable our managing general partner to attract, retain and motivate qualified executive officers that contribute to the long-term success of our managing general partner and its affiliates. The primary components of our managing general partner's executive compensation programs are:

- base salary;
- annual incentive bonus awards; and
- equity participation in the form of restricted units.

Executive officers are also entitled to customary benefits available to all of our managing general partner's employees, including group medical, dental, and life insurance and participation in our managing general partner's profit sharing and savings plan.

Base Salary. The compensation committee reviews and recommends the base salary of our managing general partner's named executive officers, as well as our other officers and key employees. When reviewing base salaries, the compensation committee considers the individual's performance, past performance of our managing general partner and the individual's contribution to that performance, the individual's level of responsibility and competitive pay practices. In general, base salaries are targeted at the middle of the competitive market place. This assessment considers relevant industry salary practices, the position's complexity and level of responsibility, its importance to our managing general partner in relation to other executive positions, and the competitiveness of an executive's total compensation. Subject to the committee's approval, the level of an executive officer's base pay is determined on the basis of relative comparative compensation data and the CEO's assessment of the executive's performance, experience, demonstrated leadership, job knowledge and management skills.

Annual Incentive Bonus Awards. To provide discretionary annual incentive bonus awards, our managing general partner maintains the STIP. The purpose of the STIP is to enhance unitholder value by providing eligible employees, including executive officers of our managing general partner, with added incentive to achieve specific annual targets. The STIP also assists our managing general partner in attracting, retaining and motivating qualified personnel in order to allow our managing general partner to remain competitive with its industry peers. The targets are intended to be aligned with our managing general partner's mission so that bonus payments are made only if unitholder interests are advanced. These targets are established prior to the beginning of each fiscal year. Under the STIP and its related guidelines, our managing general partner's executive officers and other employees selected by the compensation committee are eligible for cash bonuses based upon the comparison of our actual performance results to an annual adjusted EBITDA target. Adjusted EBITDA is defined as income before LTIP expense, net interest expense, income taxes and depreciation, depletion and amortization.

Each executive officer of our managing general partner participating in the STIP was eligible to earn a cash bonus expressed as a percentage of such officer's base salary. The incentive bonus opportunities varied by each executive officer's level of responsibility. In order to calculate the annual aggregate cash bonus amount available for discretionary awards under the STIP for employees eligible to receive such cash bonuses, the STIP provides a formula dependent on our actual adjusted EBITDA results for the year, based on a percentage of each eligible employee's base salary. For fiscal year 2004, we exceeded our annual adjusted EBITDA target so that all of the 2004 STIP participants were eligible to receive a percentage of their salary as bonus awards at the discretion of the compensation committee and/or our CEO. Bonuses are payable in the first quarter of the following calendar year.

Equity Participation. Equity compensation in the form of restricted units is a key component of our managing general partner's executive compensation program. Under the LTIP administered by the compensation committee, annual grant levels for designated employees are recommended by the CEO. The grants are made either of (a) restricted units, which are "phantom units" that entitle a grantee to receive a common unit or at the discretion of our managing general partner an equivalent amount of cash upon the vesting of a phantom unit or (b) options to purchase common units. Restricted units are vested over a stated period from the grant date. The issuance of the common units pursuant to the LTIP is intended to serve as a means of incentive compensation performance and not primarily as an opportunity to participate in the equity participation with respect to our common units. Therefore, no consideration will be payable by the plan participants upon receipt of the common units. To date, the compensation committee has not granted any unit options under the LTIP.

CEO Executive Compensation. In determining Mr. Craft's compensation, the compensation committee considered our financial performance and peer group compensation data as well as Mr. Craft's leadership, decision-making skills, experience, knowledge, communication with the board of directors and strategic recommendations. The compensation committee did not place any particular relative weight on any one of these factors, but our financial performance is generally given the most weight. The committee's decisions regarding Mr. Craft's compensation are reported to and discussed with the board of directors meeting in executive session without Mr. Craft's participation. For fiscal year 2004, Mr. Craft served as CEO of our managing general partner. Effective June 1, 2002, Mr. Craft's annual salary was increased to $334,828 from $321,950, which adjustment was determined in the manner described above. The compensation committee honored Mr. Craft's request that his salary not be increased in 2003 and 2004 even though a salary increase would have been warranted under the compensation adjustment procedure described above. Differences in Mr. Craft's annual salary as reported in the summary compensation table above are attributable to the effective date of the salary adjustment in the year 2002 and the number of weekly pay periods in a calendar year. Based on our record performance for 2004, Mr. Craft received a cash bonus (paid in fiscal year 2005) equal to approximately 112% of his base salary.

Conclusion. Based upon its review of our managing general partner's overall executive compensation program, the compensation committee has concluded that the program's structure is appropriate, competitive and effective to serve the purposes for which it was established. Moreover, the compensation committee believes that the total compensation opportunities provided to our managing general partner's executive officers creates a commonality of interest and alignment with the long-term interests of both our managing general partner and its unitholders.

Members of the Compensation Committee:

Preston R. (Jeff) Miller, Chairman

John H. Robinson

John P. Neafsey

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information as of March 1, 2005, regarding the beneficial ownership of common units held by (a) each person known by our managing general partner to be the beneficial owner of 5% or more of the common units, (b) each director and executive officer of our managing general partner and (c) all directors and executive officers of our managing general partner as a group. Our managing general partner is owned by members of management. Our special general partner is a wholly-owned subsidiary of Alliance Resource Holdings. The address of Alliance Resource Holdings, our managing general partner and our special general partner is 1717 South Boulder Avenue, Tulsa, Oklahoma 74119.

Name of Beneficial Owner	Common Units Beneficially Owned (5)	Percentage of Common Units Beneficially Owned
Alliance Resource GP, LLC (1)	7,655,311	42.22%
Joseph W. Craft III (1)(4)	7,952,691	43.86%
Robert G. Sachse (1)	12,296	*
Thomas L. Pearson (1)	18,920	*
Charles R. Wesley (1)	44,129	*
Brian L. Cantrell (1)	1,167	*
Gary J. Rathburn (1)	18,071	*
Michael J. Hall (1)	10,625	*
John J. MacWilliams (2)	654	*
Preston R. Miller, Jr. (2)	654	*
John P. Neafsey (1)	19,271	*
John H. Robinson (3)	6,653	*
All directors and executive officers as a group (9 persons)	8,085,131	44.59%

* Less than one percent

(1) The address of Alliance Resource GP, LLC and Messrs. Craft, Sachse, Pearson, Wesley, Cantrell, Rathburn, Hall, and Neafsey is 1717 South Boulder Avenue, Tulsa, Oklahoma 74119.

(2) The address of Mr. MacWilliams and Mr. Miller is The Tremont Group, LLC., 275 Grove St., Suite 2-400, Newton, Massachusetts 02466.

(3) The address of Mr. Robinson is 121 West 48th Street, Suite 1006, Kansas City, Missouri 64112.

(4) Mr. Craft may be deemed to share beneficial ownership of 7,655,311 common units held by Alliance Resource GP, LLC through Alliance Resource Holdings II, Inc., of which he is the sole director and majority shareholder. Alliance Resource Holdings II holds all of the outstanding shares of Alliance Resource Holdings, Inc., which holds all of the outstanding shares of Alliance Resource GP. Mr. Craft may be deemed to share beneficial ownership of 110,242 common units held by AMH II, LLC, of which he is the sole director and majority member. Mr. Craft may be deemed to share beneficial ownership of 9,761 common units held by Alliance Management Holdings, LLC, of which he is the sole director. 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.

(5) The amounts set forth do not include any restricted units granted under the LTIP which vest at various dates ranging from September 30, 2005 through January 1, 2008, subject to certain financial tests.

Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of March 1, 2005	Weighted-average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans as of March 1, 2005
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	298,420	N/A	70,454
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	49,929	N/A	30,071
Deferred Compensation Plan for Directors	17,970	N/A	32,030

For a description of our Supplemental Executive Retirement Plan and our Deferred Compensation Plan for Directors, please read "Supplemental Executive Retirement Plan" and "Compensation of Directors" under "Item 11. Executive Compensation."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Certain Relationships and Related Transactions

Our special general partner owns 7,655,311 common units representing an aggregate 42.2% limited partner interest in us. In addition, our general partners own, on a combined basis, an aggregate 2% general partner interest in us, the intermediate partnership and the subsidiaries. Our managing general partner's ability, as managing general partner, to control us together with our special general partner's ownership of 7,655,311 common units, effectively gives our general partners the ability to veto some of our actions and to control our management.

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

Related Party Transactions

Administrative Services. Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses they incur or payments they make on our behalf including, but not limited to, management's salaries and related benefits (including incentive compensation), and accounting, budget, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers' compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $28,536,000, $12,471,000, and $6,559,000 for the years ended December 31, 2004, 2003, and 2002, respectively. The increases from 2003 to 2004 and 2002 to 2003 were primarily attributable to higher accruals related to common unit based incentive plans, which were impacted by the increased market value of our common units, and the STIP.

Warrior Acquisition. On February 14, 2003, we acquired Warrior from an affiliate, ARH Warrior Holdings a subsidiary of Alliance Resource Holdings, pursuant to a Put/Call Agreement. Warrior purchased the capital stock of Roberts Bros. Coal Co., Inc., Warrior Coal Mining Company, Warrior Coal Corporation and certain assets of Christian Coal Corp. and Richland Mining Co., Inc. in January 2001. Our managing general partner had previously declined the opportunity to purchase these assets as we had previously committed to major capital expenditures at two existing operations. As a condition to not exercising its right of first refusal, we requested that ARH Warrior Holdings enter into a put and call arrangement for Warrior. We and ARH Warrior Holdings, with the approval of the conflicts committee of our managing general partner, entered into the Put/Call Agreement in January 2001. Concurrently, ARH Warrior Holdings acquired Warrior in January 2001 for $10.0 million.

The Put/Call Agreement preserved the opportunity for us to acquire Warrior during a specified time period. Under the terms of the Put/Call Agreement, ARH Warrior Holdings exercised its put option requiring us to purchase Warrior at a put option price of approximately $12.7 million.

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

The Put/Call Agreement option prices reflected 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 were exercised. In January 2001 and in December 2002, we developed financial projections for Warrior 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 included, among others, (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below the then current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, as of the date of the acquisition and at December 31, 2002 and 2001, we believe that the fair value of Warrior was equal to or greater than the put option exercise price.

The put option price of $12.7 million was paid to ARH Warrior Holdings in accordance with the terms of the Put/Call Agreement. In addition, we repaid Warrior's borrowings of $17.0 million under the revolving credit agreement between our special general partner and Warrior. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior that have contributed to improved productivity and significantly increased capacity. We funded the Warrior acquisition through a portion of the proceeds received from the issuance of 2,250,000 common units. Because the Warrior acquisition was between entities under common control, it has been accounted for at historical cost in a manner similar to that used in a pooling of interests.

Under the terms of the Put/Call Agreement, we assumed certain other obligations, including a mineral lease and sublease with SGP Land, a subsidiary of our special general partner, covering coal reserves that have been and will continue to be mined by Warrior. The terms and conditions of the mineral lease and sub-lease remain unchanged.

SGP Land. Dotiki has a mineral lease and sublease with SGP Land requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Dotiki paid royalties of $4,611,000, $3,460,000, and $2,700,000 for the years ended December 31, 2004, 2003 and 2002, respectively. Dotiki has recouped as earned royalties all advance minimum royalty payments made under these lease terms except for $805,000 as of December 31, 2004.

Warrior has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior has paid and will continue to pay in arrears an annual minimum royalty obligation of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments have been paid. The annual minimum royalty periods are from October 1st through the end of the following September, expiring September 30, 2007. Warrior paid royalties of $2,561,000, $2,453,000, and $2,127,000 for the years ended December 31, 2004, 2003, and 2002, respectively. Warrior has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $636,000 as of December 31, 2004.

Under the terms of the mineral lease and sublease agreements described above, Dotiki and Warrior also reimbursed SGP Land for SGP Land's base lease obligations. We reimbursed SGP Land $5,428,000, $4,395,000, and $3,922,000 for the years ended December 31, 2004, 2003 and 2002 respectively, for the base lease obligations. Dotiki and Warrior have recouped as earned royalties all advance minimum royalty payments made in accordance with these terms except for $216,000 as of December 31, 2004.

In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty 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 $479,000 and $568,000 for the years ended December 31, 2003 and 2002, respectively. The 2004 annual minimum royalty obligation of $300,000 was paid in January 2005. MC Mining has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2004.

We also have an option to lease and/or sublease certain reserves from SGP Land, which reserves are contiguous to Hopkins. Under the terms of the option to lease and sublease, we paid option fees of $1,368,000 and $684,000 during the years ended December 31, 2004 and 2003, respectively. The 2003 option fee of $684,000 was paid in January 2004 and is included in the due to affiliates balance as of December 31, 2003. The anticipated annual minimum royalty obligation is $684,000, payable in advance through 2009.

Special General Partner. Effective January 2001, Gibson entered into a noncancelable operating lease arrangement with our special general partner for its coal preparation plant and ancillary facilities. Based on the terms of the lease, Gibson has paid and will continue to make monthly payments of approximately $216,000 through January 2011. Lease expense was $2,595,000 for 2004, 2003 and 2002.

We have previously entered into and have maintained agreements with two banks to provide letters of credit in an aggregate amount of $25.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2004, we had $22.2 million in outstanding letters of credit. Our special general partner guarantees these letters of credit. Historically, we have compensated our special general partner a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. Our special general partner agreed to waive the guarantee fee in exchange for a parent guarantee from our intermediate partnership and Alliance Coal on the mineral lease and sublease with Dotiki and Warrior. We paid approximately $31,300 and $48,200 in guarantee fees to our special general partner for the years ended December 31, 2003 and 2002, respectively.

Elk Creek and Tunnel Ridge. On October 21, 2004, we announced an agreement, subject to finalization of definitive agreements, to enter into two separate coal leases, which cumulatively will increase our coal reserve holdings by 25%. The Elk Creek reserves are located in Hopkins County, Kentucky, and the Tunnel Ridge reserves are located in Ohio County, West Virginia and Washington County, Pennsylvania. These leases are estimated to contain approximately 100 million tons of high-sulfur coal reserves. The lessor for both leases is our special general partner. We also announced plans to immediately begin the development process for these properties, which includes obtaining the necessary mining permits and securing sufficient coal sales commitments to justify the capital investment needed to bring these properties into production.

The Elk Creek reserve area encompasses approximately 9,000 acres and is contiguous to our Hopkins County Coal complex. The Elk Creek coal reserves are currently estimated to include approximately 30 million tons of high-sulfur coal. The Elk Creek mine will be an underground mining complex, that mines the West Kentucky No. 9 and No. 11 coal seams. It will utilize continuous mining units and employ room-and-pillar mining techniques. We intend to use the existing coal handling and other surface facilities owned by Hopkins County Coal. We anticipate the Elk Creek complex will employ as many as 250 individuals and produce up to 3.2 million tons of coal annually. We estimate total capital expenditures to develop Elk Creek to be approximately $65.0 million. In December, 2004, the board of directors of our managing general partner approved the capital expenditures associated with Elk Creek. Coal supply commitments are currently being pursued. Construction of the Elk Creek mining complex began in the first quarter of 2005. We expect to fund these capital expenditures with available cash and marketable securities on hand, future cash generated from operations and borrowings available under our revolving credit facility.

In December 2000, Hopkins County Coal entered into an option agreement to lease and/or sublease the Elk Creek reserves from our special general partner. Under the terms of the option to lease and sublease, Hopkins County Coal paid an option fee of $645,000 during the year ended December 31, 2000, and paid option fees of $684,000 during each of the years ended December 31, 2001, 2002 and 2004. The 2003 option fee of $684,000 was paid in January 2004. Upon exercise of the option to lease or sublease, Hopkins County Coal is obligated to make an additional five annual advance minimum royalty payments of $684,000 per year, which royalty is fully recoupable against earned royalties. The earned royalty rate under the lease and/or sublease is $0.25 per ton.

In January 2005, we acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC for approximately $500,000 and the assumption of reclamation liabilities from Alliance Resource Holdings, Inc., a company owned by our management. Tunnel Ridge, LLC controls through a coal lease agreement with the special general partner an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. The Tunnel Ridge reserve area encompasses approximately 50,571 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge, LLC began paying our special general partner an advance minimum royalty of $3.0 million per year, which advance royalty payments will be fully recoupable against earned royalties. The earned royalty rate under the coal lease is the greater of $0.75 per ton or 3.0% of the per ton gross sales price f.o.b. barge. The term of the coal lease is the earlier of 30 years or until exhaustion of all mineable and merchantable coal with termination rights after the initial four years of the coal lease.

Tunnel Ridge, LLC also controls, under a separate lease agreement with our special general partner, the rights to approximately 900 acres of surface land and other tangible assets. Under the terms of the lease agreement, Tunnel Ridge, LLC shall pay our special general partner an annual lease payment of $240,000 beginning January 1, 2005. The lease agreement has an initial term of four years, which term may be extended by Tunnel Ridge, LLC at the same annual lease payment rate, to be consistent with the term of the coal lease.

We have initiated the permitting process of the Tunnel Ridge reserve area. We anticipate that the Tunnel Ridge operation will use a longwall miner for the majority of its coal extraction as well as continuous mining units used for preparation of the mine for future longwall mining. We estimate the Tunnel Ridge operation will be designed to produce up to six million tons of coal annually. We believe production from Tunnel Ridge may begin as early as 2008. We anticipate the Tunnel Ridge complex will employ as many as 300 individuals. We estimate total capital expenditures required to develop Tunnel Ridge to be approximately $200 million over a five-year period. We currently expect to fund these capital expenditures with available cash and marketable securities, future cash generated from operations and borrowings available under our revolving credit facility. A definitive commitment to develop Tunnel Ridge is dependent upon final approval by the board of directors of our managing general partner.

The Elk Creek and Tunnel Ridge transactions described above are related-party transactions and, as such, were reviewed by the board of directors of our managing general partner and its conflicts committee. Based upon these reviews, it was determined that these transactions reflect market-clearing terms and conditions customary in the coal industry. As a result, the board of directors of our managing general partner and its conflicts committee approved the Elk Creek and Tunnel Ridge transactions as fair and reasonable to us.

Other Related Party Transactions

None.

Omnibus Agreement

Concurrently with the closing of our initial public offering, we entered into an omnibus agreement with Alliance Resource Holdings and our general partners, which govern potential competition among us and the other parties to this agreement. The omnibus agreement was amended in May 2002. Pursuant to the terms of the amended omnibus agreement, Alliance Resource Holdings agreed, and caused its controlled affiliates to agree, for so long as management controls our managing general partner, not to engage in the business of mining, marketing or transporting coal in the U.S. unless it first offers us the opportunity to engage in a potential activity or acquire a potential business, and the board of directors of our 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 wherein they compete directly 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.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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

> Audit Services. Fees for audit services provided during the years ended December 31, 2004 and 2003, were $745,000 and $240,000, respectively. Audit services consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with generally accepted accounting principles.
>
> Audit-Related Services. Fees for audit-related services provided during the years ended December 31, 2004 and 2003, were $18,500 and $36,000, respectively. Audit-related services consist primarily of audits of employee benefit plans, consultations concerning financial accounting and reporting standards, and attestation services associated with third-party compliance.
>
> Tax Services. Fees for tax services provided during the years ended December 31, 2004 and 2003, were $180,000 and $231,000, respectively. Tax services relate primarily to the preparation of federal and state tax returns but can also be related to tax advice, exclusive of tax services rendered in conjunction with the audit.
>
> All Other Fees. In 2004, fees for due diligence services provided in conjunction with a proposed investment were $72,000. There were no other fees during the year ended December 31, 2003.

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

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements.

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

(a)(2) Financial Statement Schedules.

Schedule II – Valuation and Qualifying Accounts – Years ended December 31, 2004, 2003 and 2002, is set forth under Part II Item 8. - Financial Statements and Supplementary Data. All other schedules are omitted because they are not applicable or the information is shown in the financial statements or notes thereto.

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

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 22, 2003, among Alliance Resource Operating Partners, L.P., JPMorgan Chase Bank (as paying agent), Citicorp USA, Inc. and JPMorgan Chase Bank (as co-administrative agents) and lenders named therein. (Incorporated by reference to Exhibit 10.41 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 000-26823).

10.2 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).

10.3 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).

10.4 Amendment One to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of Oklahoma, National Association. (Incorporated by reference to Exhibit 10.33 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, 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 Amendment No. 1 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Fifth Third Bank. (Incorporated by reference to Exhibit 10.9 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002, File No. 000-26823).

10.9 Guarantee Agreement, dated as of August 30, 2001, between Alliance Resource GP, LLC and Fifth 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).

10.10 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).

10.11 First Amendment to the Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association. (Incorporated by reference to Exhibit 10.32 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 000-26823).

10.12 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).

10.13 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).

10.14 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).

10.15 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).

10.16 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).

10.17 Amended and Restated Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.17 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).

10.18 First Amendment to the Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.18 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).

10.19 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).

10.20 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)).

10.21 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)).

10.22 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)).

10.23 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).

10.24 Amendment No. 2 to the Restated and Amended Coal Supply Agreement effective February 28, 2002 between Webster County Coal, LLC, White County Coal, LLC, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.32 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 000-26823).

10.25 Amendment No. 3 to the Restated and Amended Coal Supply Agreement effective January 1, 2003 between Webster County Coal, LLC, White County Coal, LLC, Alliance Coal, LLC, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.39 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003, File No. 000-26823).

10.26 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).

10.27 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).

10.28 Memorandum of Understanding dated January 17, 2005 between VEPCO and Mettiki. (Incorporated by reference to Exhibit 10.2 of the Registrants Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823).

10.29 Amendment No. 1 dated January 17, 2005 between VEPCO and Mettiki to the Coal Supply Agreement. (Incorporated by reference to Exhibit 10.2 of the Registrants Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823).

10.30 Coal Feedstock Supply Agreement dated October 26, 2001, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Incorporated by reference to Exhibit 10.27 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 000-26823).

10.31 First Amendment to Coal Feedstock Supply Agreement dated February 28, 2002, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Incorporated by reference to Exhibit 10.28 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 000-26823).

10.32 Second Amendment to Coal Feedstock Supply Agreement dated April 1, 2003, between Synfuel Solutions Operating LLC and Warrior Coal, LLC. (Incorporated by reference to Exhibit 10.40 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File No. 000-26823).

10.33 Assignment and Assumption Agreement dated April 1, 2003 between Synfuel Solutions Operating LLC, Hopkins County Coal, LLC, and Warrior Coal, LLC. (Incorporated by reference to Exhibit 10.31 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).

10.34 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).

10.35 Letter Agreement dated January 31, 2003 between ARH Warrior Holdings, Inc. and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.34 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 File No. 000-26823).

10.36 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).

10.37 Extension of Consulting Agreement with Mr. Sachse, dated September 30, 2003. (Incorporated by reference to Exhibit 10.42 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 000-26823).

10.38 Form of Employee Agreements for Messrs. Craft, Pearson, 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)).

10.39	Security and Pledge Agreement dated as of May 8, 2002 by and among Alliance Resource Holdings II, Inc., AMH II, LLC, Alliance Resource Holdings, Inc., Alliance Resource GP, LLC, the Management Investors as identified therein, The Beacon Group Energy Investment Fund, L.P., MPC Partners, LP and three individuals as "Sellers" identified therein, and JPMorgan Chase Bank as collateral agent. (Incorporated by reference to Exhibit 99.2 of the Registrant's Form 8-K filed with the Commission on May 9, 2002, File No. 000-26823).
10.40	Form of Promissory Note made by Alliance Resource Holdings, Inc. dated as of May 8, 2002. (Incorporated by reference to Exhibit 99.3 of the Registrant's Form 8-K filed with the Commission on May 9, 2002, File No. 000-26823).
*10.41	Amended and Restated Charter for the Audit Committee of the Board of Directors dated March 10, 2005.
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 and Form S-8, Registration No. 333-85282 and No. 333-85258, respectively.
* 31.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 15, 2005, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 furnished herewith.
* 31.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 15, 2005, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 furnished herewith.
* 32.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 15, 2005, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith.
* 32.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 15, 2005, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith.

* Filed herewith.

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 15, 2005.

ALLIANCE RESOURCE PARTNERS, L.P.

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

/s/ Joseph W. Craft III
Joseph W. Craft III
President, Chief Executive
Officer and Director

/s/ Brian L. Cantrell
Brian L. Cantrell
Senior Vice President and
Chief Financial 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.

Signature	Title	Date
/s/ Joseph W. Craft III Joseph W. Craft III	President, Chief Executive Officer and Director (Principal Executive Officer)	March 15, 2005
/s/ Brian L. Cantrell Brian L. Cantrell	Senior Vice President and Chief Financial Officer	March 15, 2005
/s/ Michael J. Hall Michael J. Hall	Director	March 15, 2005
/s/ John J. MacWilliams John J. MacWilliams	Director	March 15, 2005
/s/ Preston R. Miller, Jr. Preston R. Miller, Jr.	Director	March 15, 2005
/s/ John P. Neafsey John P. Neafsey	Director	March 15, 2005
/s/ John H. Robinson John H. Robinson	Director	March 15, 2005
/s/ Robert G. Sachse Robert G. Sachse	Executive Vice President and Director	March 15, 2005

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 1999. As of December 31, 2004, there were 18,130,440 common and subordinated units outstanding.

CASH DISTRIBUTIONS

Alliance Resource Partners, L.P. expects to make Quarterly Distributions 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 2004 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 investorrelations@arlp.com, telephone at (918) 295-7674, visiting the Partnership's website at www.arlp.com, 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

CONTACT

Brian L. Cantrell
Senior Vice President and
Chief Financial Officer
(918) 295-7674
brian.cantrell@arlp.com

OFFICERS AND DIRECTORS

Joseph W. Craft III
President, Chief Executive Officer and Director

Robert G. Sachse
Executive Vice President and Vice Chairman of the Board

Thomas L. Pearson
Senior Vice President – Law and Administration, General Counsel and Secretary

Charles R. Wesley
Senior Vice President – Operations

Brian L. Cantrell
Senior Vice President and Chief Financial Officer

Gary J. Rathburn
Senior Vice President – Marketing

Michael J. Hall
Director

John J. MacWilliams
Director

Preston R. Miller, Jr.
Director

John P. Neafsey
Chairman of the Board

John H. Robinson
Director

NASDAQ LISTED

ALLIANCE RESOURCE PARTNERS, L.P. common units are traded on the NASDAQ National Market under the ticker symbol "ARLP."

ALLIANCE RESOURCE PARTNERS, L.P.

P.O. BOX 22027
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