ALLIANCE RESOURCE PARTNERS LP
Form 10-Q/A
June 22, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q/A

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

For the quarterly period ended March 31, 2006

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)

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 whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (check one) Large Accelerated Filer **x** Accelerated Filer ¨ Non-Accelerated Filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

As of May 10, 2006, 36,426,306 Common Units are outstanding.

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This Amendment No. 1 on Form 10-Q/A is being filed to restate the selected production expenses disclosed in Note 10, Segment Information, to the condensed consolidated financial statements included in Part 1 Item 1. Production taxes and royalties were inadvertently added rather than deducted from combined operating expenses and outside purchases in calculating selected production expenses. Item 4. Controls and Procedures has been revised to address the issue concerning our internal controls over financial reporting raised by the restatement of selected productions expenses. Except to the extent affected by the correction of this error, no other information included in the original report on Form 10-Q is amended by this Form 10-Q/A.

Additionally, except for the foregoing amended information, the Form 10-Q/A continues to describe conditions as of the date of the original Form 10-Q and the Partnership has not updated the disclosure contained herein to reflect events that occurred subsequently. Accordingly, the Form 10-Q/A should be read in conjunction with Partnership filings made with the Securities and Exchange Commission subsequent to the filing of the original Form 10-Q, including any amendments to those filings.

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PART 1

FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except unit data)

(Unaudited)

	March 31, 2006	December 31, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 43,450	$ 32,054
Trade receivables, net	94,537	94,495
Other receivables	2,755	2,330
Marketable securities	39,397	49,242
Inventories	23,685	17,270
Advance royalties	2,952	2,952
Prepaid expenses and other assets	6,088	8,934
Total current assets	212,864	207,277
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment at cost	679,228	635,086
Less accumulated depreciation, depletion and amortization	(344,819)	(330,672)
Total property, plant and equipment	334,409	304,414
OTHER ASSETS:		
Advance royalties	18,362	16,328
Other long-term assets	4,521	4,668
Total other assets	22,883	20,996
TOTAL ASSETS	$ 570,156	$ 532,687
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 60,738	$ 53,473
Due to affiliates	2,040	8,795
Accrued taxes other than income taxes	14,603	13,177
Accrued payroll and related expenses	14,550	12,466
Accrued pension benefit	8,519	7,588
Accrued interest	1,421	4,855
Workers compensation and pneumoconiosis benefits	7,813	7,740
Other current liabilities	4,952	5,120

Current maturities, long-term debt	18,000	18,000
Total current liabilities	132,636	131,214
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	144,000	144,000
Pneumoconiosis benefits	24,002	23,293
Workers compensation	31,754	30,050
Reclamation and mine closing	39,177	38,716
Due to affiliates	5,490	6,940
Other liabilities	2,835	2,697
Total long-term liabilities	247,258	245,696
Total liabilities	379,894	376,910
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Limited Partners - Common Unitholders 36,426,306 units outstanding	494,994	461,068
General Partners deficit	(297,727)	(298,270)
Unrealized loss on marketable securities	(52)	(68)
Minimum pension liability	(6,953)	(6,953)
Total Partners capital	190,262	155,777
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 570,156	$ 532,687

See notes to condensed consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except unit and per unit data)

(Unaudited)

	Three Months Ended March 31, 2006	2005
SALES AND OPERATING REVENUES:		
Coal sales	$ 218,212	$ 178,846
Transportation revenues	10,034	9,623
Other sales and operating revenues	10,074	7,158
Total revenues	238,320	195,627
EXPENSES:		
Operating expenses	152,010	119,393
Transportation expenses	10,034	9,623
Outside purchases	3,526	4,117
General and administrative	7,158	5,708
Depreciation, depletion and amortization	14,722	13,628
Interest expense (net of interest income and interest capitalized for the three months ended March 31, 2006 and 2005 of $1,327 and $472, respectively)	2,245	3,474
Total operating expenses	189,695	155,943
INCOME FROM OPERATIONS	48,625	39,684
OTHER INCOME	271	105
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	48,896	39,789
INCOME TAX EXPENSE	759	710
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	48,137	39,079
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	112	
NET INCOME	$ 48,249	$ 39,079
GENERAL PARTNERS INTEREST IN NET INCOME	$ 4,844	$ 1,685
LIMITED PARTNERS INTEREST IN NET INCOME	$ 43,405	$ 37,394
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.83	$ 0.71
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.83	$ 0.70
DISTRIBUTIONS PAID PER COMMON AND SUBORDINATED UNIT	$ 0.46	$ 0.375

WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING-BASIC	36,426,306	36,260,880
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING-DILUTED	36,765,016	36,992,828

See notes to condensed consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 67,640	$ 28,504
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(44,714)	(16,914)
Changes in accounts payable and accrued liabilities	(567)	
Proceeds from sale of property, plant and equipment	418	193
Purchase of marketable securities	(4,735)	(9,727)
Proceeds from marketable securities	14,596	9,721
Net cash used in investing activities	(35,002)	(16,727)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Distributions to Partners	(21,242)	(14,797)
Net cash used in financing activities	(21,242)	(14,797)
NET CHANGE IN CASH AND CASH EQUIVALENTS	11,396	(3,020)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	32,054	31,177
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 43,450	$ 28,157
CASH PAID FOR:		
Interest	$ 6,864	$ 7,546
Income taxes to taxing authorities	$ 1,025	$ 250
NON-CASH INVESTING ACTIVITY		
Purchase of property, plant and equipment	$ 8,797	$

See notes to condensed consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Note 10 Restated)

(Unaudited)

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 accompanying condensed consolidated financial statements include the accounts and operations of the Partnership and present the financial position as of March 31, 2006 and December 31, 2005, and the results of its operations and cash flows for the three months ended March 31, 2006 and 2005. All material intercompany transactions and accounts of the Partnership have been eliminated.

On September 15, 2005, the Partnership completed a two-for-one split of the Partnership s common units, whereby holders of record at the close of business on September 2, 2005 received one additional common unit for each common unit owned on that date. The unit split resulted in the issuance of 18,130,440 common units. For all periods presented, all references to the number of units and per unit net income and distribution amounts included in this report have been adjusted to give effect for the unit split.

These condensed consolidated financial statements and notes are unaudited. However, in the opinion of management, these financial statements reflect all adjustments (which include only normal recurring adjustments) necessary for a fair presentation of the results for the periods presented. Results for interim periods are not necessarily indicative of results for a full year.

These condensed consolidated financial statements and notes are prepared pursuant to the rules and regulations of the Securities and Exchange Commission for interim reporting and should be read in conjunction with the consolidated financial statements and notes included in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2005.

2. CONTINGENCIES

The Partnership is involved in various lawsuits, claims and regulatory proceedings incidental to its business. Disputes between the Partnership and its 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. The Partnership is not involved in any litigation relating to any of the Partnership s long-term coal supply contracts. However, we cannot assure you that disputes will not occur or that the Partnership will be able to resolve those disputes in a satisfactory manner. The Partnership is not engaged in any litigation that we believe is material to the Partnership s operations, including under the various environmental protection statutes to which the Partnership is subject. The Partnership provides for costs related to litigation and regulatory proceedings, including civil fines issued as part of the outcome of these 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, is 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.

During October 2005, the Partnership completed its annual property and casualty insurance renewal with various insurance coverages effective as of October 1, 2005. Available capacity for underwriting property insurance has tightened as a result of recent events including insurance carrier losses associated with U.S. gulf coast hurricanes, poor loss claims history in the underground coal mining industry and our recent loss history (i.e., Pattiki Vertical Belt Incident, MC Mining Fire Incident, and Dotiki Fire Incident). As a result, the Partnership will retain a participating interest along with our insurance carriers at an average rate of approximately 10% in the $75 million commercial property program. The aggregate maximum limit in the commercial property program is $75 million per occurrence of which we would be responsible for a maximum amount of $7.75 million for each occurrence, excluding a $1.5 million deductible for property damage and a 45-day waiting period for business interruption. As a result of the renewal for comparable levels of commercial property coverage, premiums for the property insurance program increased by approximately 130%. The Partnership can make no assurances that it will not experience significant insurance claims in the future, which as a result of the participation in the commercial property program, could have a material adverse effect on the business, financial conditions, results of operations and ability to purchase property insurance in the future.

The Partnership s subsidiary, Mettiki Coal (WV), LLC, is developing an underground longwall mine in Tucker County, West Virginia (referred to as the Mountain View Mine or E-Mine), which will eventually replace Mettiki Coal s existing longwall mining operation at the D-Mine located in Garrett County, Maryland. The Mountain View Mine is located approximately 10 miles from Mettiki Coal. In order to proceed with development of the Mountain View Mine, Mettiki Coal (WV) submitted various permit applications to the West Virginia Department of Environmental Protection, or WVDEP, including an application for approval to conduct underground mining. WVDEP issued the required permits in the Spring of 2004. Certain complainants appealed WVDEP s decision issuing the underground mining permit to the West Virginia Surface Mine Board, or SMB, which held administrative hearings on the matter in late 2004 and early 2005. On March 8, 2005, the SMB on a divided 3-3 vote issued a final order concluding consideration of the appeal without effectively rendering a decision, which, by operation of West Virginia law, resulted in the affirmation of WVDEP s decision to issue the underground mining permit. The complainants appealed the SMB decision, but subsequently voluntarily agreed to withdraw the appeal, which was dismissed with prejudice by the Tucker County circuit court in West Virginia on April 26, 2005.

On April 19, 2005, these same complainants submitted a letter to the U.S. Department of the Interior s Office of Surface Mining, Reclamation and Enforcement, or OSM, and the OSM s regional field office in Charleston, West Virginia, or CHFO, requesting federal monitoring and inspection of the Mountain View Mine and alleging that operations at the mine would create acid mine drainage with no defined end point. By written notice dated April 21, 2005, the CHFO advised WVDEP that it would review the complainants allegation that the Mountain View Mine would cause material harm to the hydrological balance within and outside of the permit area. Following its initial review, on September 15, 2005, the CHFO notified WVDEP that it intended to initiate a formal investigation into the issuance of the underground mining permit for the Mountain View Mine. WVDEP requested an informal review of the CHFO decision by the OSM. By two letters, both dated October 21, 2005, OSM reversed the decision of the CHFO concluding that the CHFO and OSM lacked statutory authority to review the WVDEP s issuance of the underground mining permit, and the Department of the Interior ordered that this was the Department s final decision on the matter raised in the complainants letter dated April 19, 2005. The Mountain View Mine is not currently subject to any pending or threatened agency or third-party claims. However, on March 8, 2006, these same complainants requested that the Director of OSM evaluate West Virginia s State Program pursuant to 30 C.F.R. §§ 733 et seq., but acknowledged a similar request had been made on April 19, 2005, which request had been previously rejected by the Department of Interior s final decision on October 21, 2005. In a letter dated March 24, 2006, the Department of the Interior denied the complainants request and stated that this denial was the final decision of the Department of Interior.

On October 12, 2004, Pontiki Coal, LLC (Pontiki) one of the Partnership s subsidiaries and the successor-in-interest of Pontiki Coal Corporation as a result of a merger completed on August 4, 1999, was served with a complaint from ICG, LLC (ICG) alleging breach of contract and seeking declaratory relief to

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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, which we refer to as the Horizon Agreement. ICG has represented that it acquired the rights and assumed the liabilities of the Horizon 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.

The complaint alleged that from January 2004 to August 2004, Pontiki failed to deliver a total of 138,111 tons of coal that met the contract delivery and quality specifications resulting in an alleged loss of profits for ICG of $4.1 million. The Partnership is aware that certain deliveries under the Horizon Agreement were not 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 Horizon Agreement. In November 2005, the Partnership settled this contract dispute with ICG. Under this settlement, effective August 1, 2005, Pontiki will ship coal in approximately ratable monthly quantities until the remaining contract obligation of 1,681,303 tons is shipped, and this contract will terminate on or by December 31, 2006. Under the terms of the settlement, the existing coal supply agreement was amended to change the coal quality specifications and to exclude from the definition of force majeure the events of railroad car shortages and geological and quality issues with respect to coal. As part of this settlement, the Partnership and ICG also executed a new coal sales agreement whereby another subsidiary of the Partnership will purchase 892,000 tons of coal from ICG. Approximately 63,000 tons and 149,000 tons were purchased and sold at a profit during 2005 and the three months ended March 31, 2006, respectively, and the remaining 680,000 tons are expected to be purchased and sold at a profit during the remainder of 2006. These agreements will expire on or by December 31, 2006.

At certain of the Partnership s operations, property tax assessments for several years are under audit by various state 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.

3. TUNNEL RIDGE ACQUISITION

In January 2005, the Partnership acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC (Tunnel Ridge), for approximately $500,000 and the assumption of reclamation liabilities from ARH, a company owned by management of the Partnership. Tunnel Ridge controls through a coal lease agreement with Alliance Resource GP, LLC (the Special GP) approximately 9,400 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania containing an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge has paid and will continue to pay the Special GP an advance minimum royalty of $3.0 million per year. The advance royalty payments are fully recoupable against earned royalties.

The Tunnel Ridge transaction described above was a related-party transaction and, as such, was reviewed by the Board of Directors of Alliance Resource Management GP, LLC (the Managing GP) and its Conflicts Committee. Based upon these reviews, the Conflicts Committee 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 Tunnel Ridge acquisition as fair and reasonable to the Partnership and its limited partners.

4. MINE FIRE INCIDENT

MC Mining Mine Fire

On December 26, 2004, MC Mining, LLC s 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 U.S. Department of Labor s Mine Safety and Health Administration (MSHA) and Kentucky Office of Mine Safety and Licensing, the four portals at the Excel No. 3 mine were temporarily capped to deprive the fire of oxygen. A series of boreholes was then drilled into the mine from the surface, and nitrogen gas and foam were injected through the boreholes 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. Once the 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. Coal production has returned to near normal levels, but continues to be adversely impacted by inefficiencies attributable to or associated with the MC Mining Fire Incident.

The Partnership maintains commercial property (including business interruption and extra expense) insurance policies with various underwriters, which policies are renewed annually in October 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). The Partnership believes such insurance coverage will cover a substantial portion of the total cost of the disruption to MC Mining s operations. However, concurrent with the renewal of the Partnership s commercial property (including business interruption) insurance policies concluded on October 31, 2005, MC Mining confirmed with the current underwriters of the commercial property insurance coverage that any negotiated settlement of the losses arising from or in connection with the MC Mining Fire Incident would not exceed $40.0 million (inclusive of co-insurance and deductible amounts). Until the claim is resolved ultimately, through the claim adjustment process, settlement, or litigation, with the applicable underwriters, the Partnership can make no assurance of the amount or timing of recovery of insurance proceeds.

The Partnership made an initial estimate of certain costs primarily associated with activities relating to the suppression of the fire and the initial resumption of operations. Operating expenses for the 2004 fourth quarter were increased by $4.1 million to reflect 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.

Following the initial two submittals by the Partnership to a representative of the underwriters of its estimate of the expenses and losses (including business interruption losses) incurred by MC Mining and other affiliates arising from and in connection with the MC Mining Fire Incident (the MC Mining Insurance Claim), on September 15, 2005, the Partnership filed a third estimate of its expenses and losses, with an update through July 31, 2005. Partial payments of $2.9 million and $12.2 million were received during April 2006 and the year ended December 31, 2005, respectively, these amounts are net of the 2005 Deductibles and 2005 Co-Insurance. The accounting for these partial payments and future payments, if any, made to the Partnership by the underwriters will be subject to the accounting methodology described below. On March 23, 2006, the Partnership filed a third partial proof of loss for the period through July 31, 2005 in the amount of $4.0 million. Currently, the Partnership continues to evaluate its potential insurance recoveries under the applicable insurance policies in the following areas:

1. Fire Brigade/Extinguishing/Mine Recovery Expense; Expenses to Reduce Loss; Debris Removal Expenses; Demolition and Increased Cost of Construction; Expediting Expenses; and Extra Expenses incurred as a result of the fire These expenses and other costs (e.g. professional fees) associated with extinguishing the fire, reducing the overall loss, demolition of certain property and removal of debris, expediting the recovery from the loss, and extra expenses that would not have been incurred by the Partnership but for the MC Mining Fire Incident, are being expensed as incurred with related actual and/or estimated insurance recoveries recorded as they are considered to be probable, up to the amount of the actual cost incurred.

2. Damage to MC Mining mine property - The net book value of property destroyed of $154,000, was written off in the first quarter of 2005 with a corresponding amount recorded as an estimated insurance recovery, since such recovery is considered probable. Any insurance proceeds from the claims relating to the MC Mining mine property (other than amounts relating to the matters discussed in 1. above) that exceed the net book value of such damaged property are expected to result in a gain. The anticipated gain will be recorded when the MC Mining Insurance Claim is resolved and/or proceeds are received.

3. MC Mining mine business interruption losses The Partnership has submitted to a representative of the underwriters a business interruption loss analysis for the period of December 24, 2004 through July 31, 2005. Expenses associated with business interruption losses are expensed as incurred, and estimated insurance recoveries of such losses are recognized to the extent such recoveries are considered to be probable, up to the actual amount incurred. Recoveries in excess of actual costs incurred will be recorded as gains when the MC Mining Insurance Claim is resolved and/or proceeds are received.

Pursuant to the accounting methodology described above, the Partnership has recorded as an offset to operating expenses, $0.4 million and $9.2 million, during the three months ended March 31, 2006 and 2005, respectively, and $10.7 million for the year ended December 31, 2005. These amounts represent the current estimated insurance recovery of actual costs incurred, net of the 2005 Deductibles and 2005 Co-Insurance. The Partnership continues to discuss the MC Mining Insurance Claim and the determination of the total claim amount with representatives of the underwriters. The MC Mining Insurance Claim will continue to be developed as additional information becomes available and the Partnership has completed its assessment of the losses (including the methodologies associated therewith) arising from or in connection with the MC Mining Fire Incident. At this time, based on the magnitude and complexity of the MC Mining Insurance Claim, the Partnership is unable to reasonably estimate the total amount of the MC Mining Insurance Claim as well as its exposure, if any, for amounts not covered by its insurance program.

5. NET INCOME PER LIMITED PARTNER UNIT

In March 2004, the FASB issued EITF No. 03-6, which addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. Essentially, EITF No. 03-6 provides that in any accounting period where the Partnership s aggregate net income exceeds the aggregate distributions for such period, the Partnership is required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic probability standpoint. EITF No. 03-6 was effective for fiscal periods beginning after March 31, 2004. EITF No. 03-6 does not impact the Partnership s aggregate distributions for any period, but it can have the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of the Partnership s aggregate earnings, as if distributed, is allocated to the incentive distribution rights held by the Managing GP, even though the Partnership makes cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such period, EITF No. 03-6 does not have any impact on the Partnership s earnings per unit calculation.

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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):

	Three Months Ended March 31, 2006	2005
Net income	$ 48,249	$ 39,079
Adjustments:		
General partners priority distributions	(3,958)	(922)
General partners 2% equity ownership	(886)	(763)
Limited partners interest in net income	$ 43,405	$ 37,394
Additional earnings allocation to general partners	(13,052)	(11,655)
Net income available to limited partners under EITF No. 03-6	30,353	25,739
Weighted average limited partner units basic	36,426	36,261
Basic net income per limited partner unit	$ 0.83	$ 0.71
Weighted average limited partner units basic	36,426	36,261
Units contingently issuable:		
Restricted units for Long-Term Incentive Plan	189	596
Directors compensation units	40	36
Supplemental Executive Retirement Plan	110	100
Weighted average limited partner units, assuming dilutive effect of restricted units	36,765	36,993
Diluted net income per limited partner unit	$ 0.83	$ 0.70

The Partnership s net income for partners capital purposes 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, if any, to the Partnership s managing GP, the holder of the incentive distributions rights pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. For purposes of computing basic and diluted net income per limited partner unit, in periods when the Partnership s aggregate net income exceeds the aggregate distributions for such periods, an increased amount of net income is allocated to the general partner for the additional pro forma priority income attributable to the application of EITF No. 03-6.

The Partnership s 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 $0.275 per unit, 25% of the amount the Partnership distributes in excess of $0.3125 per unit and 50% of the amount the Partnership distributes in excess of $0.375 per unit.

6. COMMON UNIT-BASED COMPENSATION

Effective January 1, 2000, the Managing GP adopted 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. On December 22, 2005, the Compensation Committee executed a unanimous consent resolution that, effective January 1, 2006, (a) all existing grants made under the LTIP prior to January 1, 2006 and subsequent thereto be settled, upon satisfaction of any applicable vesting requirements, in Common Units to the extent of net share settlement for minimum statutory income tax withholding requirements for each individual participant based upon the fair market value of the Common Units as of the date of payment and (b) any existing and prospective LTIP grants of restricted units receive quarterly distributions as provided in the distribution equivalent rights provision of the LTIP. Therefore, each LTIP participant will have a contingent right to receive an amount equal to the cash distributions made by the Partnership during the vesting period.

The aggregate number of units reserved for issuance under the LTIP is 1,200,000. Effective January 1, 2004, the Compensation Committee approved an amendment to the LTIP clarifying that any award that is forfeited, expires for any reason, or is paid or settled in cash, including the satisfaction of minimum statutory withholding requirements, rather than through the delivery of units will be available for future grants under the LTIP. Of the initial 1,200,000 units reserved for issuance under the LTIP, cumulative units of 1,092,780 were granted in years 2000, 2001, 2002 and 2003. Of those grants, 43,650 units were forfeited and 421,452 units were settled in cash rather than delivery of units, resulting in the net issuance of 627,678 Common Units under those grants. During 2004, 2005 and 2006, the Compensation Committee approved grants of 205,570 units, 114,390 units and 85,275 units, respectively, which will vest December 31, 2006, January 1, 2008 and January 1, 2009, respectively subject to the satisfaction of certain financial tests that management currently believes will be satisfied. As of March 31, 2006, 3,690 outstanding LTIP grants have been forfeited. During the three months ended March 31, 2006 and 2005 the Managing GP billed the Partnership approximately $1,060,000 and $489,000, respectively, attributable to the LTIP.

Effective January 1, 2006, the Partnership adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123R, *Share-Based Payment* using the modified prospective transition method. 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, of 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 pro forma disclosures made in accordance with SFAS No. 123. The Partnership used the modified prospective method of adoption provided under SFAS No. 123R and, therefore, it did not restate prior period results.

The Partnership historically accounted for the compensation expense of the non-vested restricted common units granted under the LTIP using the intrinsic value method prescribed in Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees and the related FASB Interpretation No. 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans*. Compensation cost for the restricted Common Units was 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. Because the Partnership had previously expensed share-based payments using the current market value of the Partnership s Common Units at the end of each period, the adoption of SFAS No. 123R did not have a material impact on the Partnership s consolidated results of operations.

The intrinsic value of the 2005 and 2004 grants of $37.20 per LTIP grant at December 31, 2005 essentially equals the fair value at January 1, 2006 and, therefore, no incremental compensation cost was recognized upon adoption of SFAS 123R. As required by SFAS No. 123R, the fair value was reduced for expected forfeitures, to the extent compensation cost had been previously recognized and the Partnership recorded a benefit of $112,000 for the three months ended March 31, 2006 as a cumulative effect of accounting change. The Partnership expects to settle the non-vested LTIP grants by delivery of Common Units, except for the portion of the grants that will satisfy the minimum statutory income tax withholding requirements. Consequently, the previously recognized liability reflected in the due to affiliates current and long-term accounts in the consolidated balance sheet at December 31, 2005 was reclassified to Partners Capital upon adoption of 123R on January 1, 2006. The fair value of the 2006 grants is based upon the intrinsic value at the date of grant which was $37.91 per LTIP grant.

A summary of non-vested LTIP grants as of and for the three months ended March 31, 2006 is as follows:

Non-vested grants at January 1, 2006	316,270
Granted	85,275
Vested	
Forfeited	
Non-vested grants at March 31, 2006	401,545

As of March 31, 2006, there was $7,219,000 in total unrecognized compensation cost related to the non-vested LTIP grants. That cost is expected to be recognized over a weighted-average period of 1.5 years. As of March 31, 2006, the intrinsic value of the nonvested LTIP grants was $14,190,000.

The total obligation associated with the LTIP as of March 31, 2006 was $7,462,000 and is included in Partners Capital-Limited Partners. The total obligation associated with the LTIP as of December 31, 2005 was $6,517,000 and is included in the current and long-term liabilities due to affiliates contained in the condensed consolidated balance sheets.

Consistent with the disclosure requirements of SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, an amendment of SFAS No. 123, *Accounting for Stock-Based Compensation*, the following table demonstrates that compensation cost for the non-vested restricted units granted under the LTIP is the same under both the intrinsic value method and the provisions of SFAS No. 123 (in thousands, except per unit data):

		Three Months Ended March 31, 2005
Net income, as reported	$	39,079
Add: compensation expenses related to Long-Term Incentive Plan units included in reported net income		489
Deduct: compensation expense related to Long-Term Incentive Plan units determined under fair value method for all awards		(489)
Net income, pro forma	$	39,079
General partners interest in net income, pro forma	$	1,685
Limited partners interest in net income, pro forma	$	37,394
Earnings per limited partner unit:		
Basic, as reported	$	0.71
Basic, pro forma	$	0.71
Diluted, as reported	$	0.70

Diluted, pro forma	$	0.70

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7. COMPONENTS OF PENSION PLAN NET PERIODIC BENEFIT COSTS

Components of the net periodic costs for each of the periods presented are as follows (in thousands):

	Three Months Ended March 31,	
	2006	2005
Service cost	$ 829	$ 813
Interest cost	487	417
Expected return on plan assets	(567)	(483)
Prior service cost	11	13
Net loss	78	50
Basic, as reported	$ 838	$ 810

The partnership previously disclosed in its financial statements for the year ended December 31, 2005, that it expected to contribute $7,900,000 to the Pension Plan in 2006. The Partnership typically makes a single contribution to its Pension Plan in the third quarter of a year. As of March 31, 2006, the Partnership had made no contributions to the Pension Plan in 2006.

8. MINE DEVELOPMENT

The Partnership has mine development activities in progress at its River View, Mountain View, Elk Creek and Pontiki underground mines. Mine development costs are capitalized and represent costs that establish access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels.

9. 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, Chapter 4, Paragraph 5 of ARB No. 43, items such as idle facility expense, excessive spoilage, double freight, and re-handling 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. The Partnership s adoption of SFAS No. 151 on January 1, 2006 did not affect the Partnership s consolidated financial statements.

The Partnership adopted SFAS No. 123R effective on January 1, 2006. The Partnership used the modified prospective method of adoption provided under SFAS No. 123R and, therefore, did not restate prior period results (Note 6).

In March 2005, the FASB issued EITF No. 04-6, *Accounting for Stripping Costs in the Mining Industry*, and concluded that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF No. 04-6 does not address the accounting for stripping costs incurred during the pre-production phase of a mine. EITF No. 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005 with early adoption permitted. The effect of initially applying this consensus would be accounted for in a manner similar to a cumulative effect adjustment. Since the Partnership has historically adhered to the accounting principles similar to EITF No. 04-6 in accounting for stripping costs incurred at the Partnership s surface operation, the Partnership s adoption of EITF No. 04-6, effective January 1, 2006 did not have a material impact on its consolidated financial statements.

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10. SEGMENT INFORMATION (RESTATED)

The Partnership operates in the eastern United States as a producer and marketer of coal to major United States utilities and industrial users, also located in the eastern United States. The Partnership has the following three reportable segments: the Illinois Basin, Central Appalachia and Northern Appalachia. The segments also represent the three major coal deposits in the eastern United States. Coal quality, coal seam height, transportation methods and regulatory issues are similar within each of these three segments. The Illinois Basin segment is comprised of the Dotiki, Gibson, Hopkins, Pattiki and Warrior mines. Central Appalachia segment is comprised of the Pontiki and MC Mining mines. Northern Appalachia segment is comprised of the Mettiki, Mountain View, Tunnel Ridge and Penn Ridge mines. The Mountain View mine is currently being developed to eventually replace production from the Mettiki mine, which is expected to deplete its coal reserves in late 2006. The Partnership is in the process of permitting the Tunnel Ridge and Penn Ridge properties for future mine development.

Operating segment results for the three months ended March 31, 2006 and 2005 are presented below. Other and Corporate, includes marketing and administrative expenses, the Mt. Vernon Transfer Terminal and coal brokerage activity.

	Illinois Basin	Central Appalachia	Northern Appalachia	Other and Corporate (1)	Consolidated
			(in thousands)		
Operating segment results for the three months ended March 31, 2006 were as follows:					
Total revenues	$ 155,347	$ 48,169	$ 28,304	$ 6,500	$ 238,320
Selected production expenses Restated (2)	82,638	30,576	14,674	3,921	131,809
Segment Adjusted EBITDA (3)	51,311	11,904	7,885	1,921	73,021
Total assets	297,658	90,344	86,002	96,152	570,156
Capital expenditures (4)	29,560	3,805	8,174	3,175	44,714
Operating segment results for the three months ended March 31, 2005 were as follows:					
Total revenues	$ 136,292	$ 24,440	$ 33,955	$ 940	$ 195,627
Selected production expenses Restated (2)	70,032	17,616	15,578	361	103,587
Segment Adjusted EBITDA (3)	45,979	3,768	12,441	411	62,599
Total assets	232,889	79,162	53,960	81,388	447,399
Capital expenditures	11,304	3,228	2,150	232	16,914

(1) Revenues included in the Other and Corporate column are attributable to Mt. Vernon Transfer Terminal transloading revenues and brokerage coal sales.

(2) Selected production expenses is comprised of operating expenses and outside purchases (as reflected in the Consolidated Statements of Income), excluding production taxes and royalties that are incurred as a percentage of coal sales or volumes. The calculation of selected production expenses has been restated because in the original Form 10-Q, production taxes and royalties were added rather than deducted from combined operating expenses and outside purchases. Selected production expenses as previously presented and as restated are as follows:

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	Illinois Basin	Central Appalachia	Northern Appalachia	Other and Corporate (1)	Consolidated
			(in thousands)		
As Previously Reported					
Year 2006 Quarter	$ 114,304	$ 40,554	$ 20,109	$ 4,294	$ 179,261
Year 2005 Quarter	98,696	22,570	21,468	699	143,433
As Restated					
Year 2006 Quarter	82,638	30,576	14,674	3,921	131,809
Year 2005 Quarter	70,032	17,616	15,578	361	103,587

(3) Segment adjusted EBITDA is defined as net income before income tax expense (benefit), interest expense and interest income, depreciation, depletion and amortization, and general and administrative expense.

(4) Capital expenditures includes items received but not yet paid, which is disclosed as non-cash activity, purchase of property, plant and equipment in the supplemental cash flow information in the Consolidated Statements of Cash Flows.

	Three Months Ended March 31, 2006	2005
	(in thousands)	
Reconciliation of Segment Adjusted EBITDA to net income:		
Segment Adjusted EBITDA	$ 73,021	$ 62,599
General & administrative	(7,158)	(5,708)
Depreciation, depletion and amortization	(14,722)	(13,628)
Interest expense	(2,245)	(3,474)
Income taxes	(759)	(710)
Cumulative effect of accounting change	112	
Net Income	$ 48,249	$ 39,079
Reconciliation of Selected Production Expenses to Combined Operating Expenses and Outside Purchases (Restated):		
Selected production expenses (Restated)	$ 131,809	$ 103,587
Production taxes and royalties (Restated)	23,727	19,923
Combined operating expenses and outside purchases	$ 155,536	$ 123,510

This reconciliation has been restated because of the calculation correction described in Note (2) above.

11. SUBSEQUENT EVENTS

On April 12, 2006, the Partnership announced that Alliance Coal, LLC, its wholly-owned subsidiary, acquired the rights to approximately 99.3 million tons of high sulfur coal reserves in Union County, Kentucky. As a result of the purchase of all of the members interests of River View Coal, LLC, or River View, the Partnership gained control of approximately 89.7 million tons of coal by lease and approximately 9.6 million tons of coal through direct ownership in the Kentucky No. 7, No. 9 and No. 11 coal seams, along with related surface properties and other assets. The Partnership intends to develop the River View mine as an underground mining complex utilizing continuous mining units employing room-and-pillar mining techniques. The Partnership estimates the River View mining complex will be designed to produce annually up to 3.5 million tons of coal. Total capital expenditures required to develop the River View reserves are currently estimated to be in the range of approximately $110 to $130 million over a four-year period. It is currently anticipated that the River View complex will begin production in the 2008-2009 time frame and employ as many as 300 workers. Definitive development commitment for River View is dependent upon final approval of the board of directors of the Partnership s managing general partner.

On April 13, 2006 the Partnership s wholly-owned subsidiary Alliance Resource Operating Partners, L.P. (the Intermediate Partnership) entered into an amended and restated credit facility (Amended Credit Facility). The Amended Credit Facility is for $100.0 million and has an expiration date of April 13, 2011. This Amended Credit Facility replaces an $85 million credit facility (Credit Facility) that would have expired in September 2006. The interest rate on the Amended Credit Facility fluctuates based on the LIBOR rate and the financial performance of the Intermediate Partnership. Initially, the interest rate will be the LIBOR rate plus 0.875%. The Amended Credit Facility contains events of default provisions that could cause the acceleration of the term if an event of default occurs. The Intermediate Partnership may request that the aggregate amount of the Amended Credit Facility be increased up to $150 million, subject to lender approval.

On April 19, 2006 the Partnership received a letter from the managing member of Synfuel Solutions Operating, LLC (SSO), which stated that effective April 23, 2006, due to the increase in the wellhead price of domestic crude oil, SSO has elected to exercise its contractual right to suspend until further notice operation of its coal synfuel production facility located at the Partnership s Warrior Coal, LLC (Warrior), mining complex in Hopkins County, Kentucky. The Partnership receives fees from coal sales, rental, marketing and other services provided to SSO pursuant to various long-term agreements associated with the coal synfuel facility located at Warrior. These agreements, which expire on December 31, 2007, are dependent on the ability of SSO to use certain qualifying federal income tax credits available to the coal synfuel facility and are subject to early cancellation if the synfuel tax credits become unavailable to SSO due to a rise in the price of crude oil or otherwise. SSO has advised the Partnership that resumption of operations of the synfuel facility is dependent on the price of crude oil in the future. In anticipation of the suspension of operations at the SSO coal synfuel production facility, the Partnership will sell coal directly to SSO s synfuel customers under back up coal supply agreements, which automatically provide for the sale of the Partnership s coal in the event these customers do not purchase coal synfuel from SSO. The Partnership has also entered into agreements with the owners of two other coal synfuel production facilities PC Indiana Synthetic Fuel #2, L.L.C. (PCIN), related to its coal synfuel facility located at the Partnership s Gibson County Coal, LLC mining complex in Gibson County, Indiana and Mt. Storm Coal Supply, (Mt. Storm Coal Supply), related to its coal synfuel facility located at Virginia Electric and Power Company s Mt. Storm power station, which is adjacent to the Partnership s Mettiki Coal, LLC mining complex in Garrett County, Maryland. The PCIN and Mt. Storm Coal Supply synfuel facilities currently remain in operation; however, the continued operation of these facilities cannot be assured as the operators of these facilities have similar contractual rights to suspend production due to higher oil prices. Pursuant to its agreement with SSO, the Partnership is not obligated to make retroactive adjustments or reimbursements if SSO s synfuel tax credits are disallowed.

Alliance Holdings GP, L.P. (AHGP) is a Delaware limited partnership that was formed on November 10, 2005 to become the sole member of the Managing GP. AHGP initiated its initial public offering (the IPO) on May 9, 2006 and expects to close the IPO on May 15, 2006. Upon the closing of the IPO, AHGP will own 100 percent of the members interest of the Managing GP, L.P., a 0.001% managing interest in Alliance Coal, LLC, the incentive distribution rights in the Partnership associated with the Managing GP, and 15,550,628 common units of the Partnership.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SUMMARY

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 fifth largest coal producer in the eastern United States. We currently operate eight underground mining complexes in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia and one surface operation in Kentucky.

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On April 19, 2006, we received a letter from the managing member of Synfuel Solutions Operating, LLC (SSO), which stated that effective April 23, 2006, due to the increase in the wellhead price of domestic crude oil, SSO has elected to exercise its contractual right to suspend, until further notice, operation of its coal synfuel production facility located at our Warrior Coal, LLC (Warrior) mining complex in Hopkins County, Kentucky. We receive fees from coal sales, rental, marketing and other services provided to SSO pursuant to various long-term agreements associated with the coal synfuel facility located at Warrior. These agreements, which expire on December 31, 2007, are dependent on the ability of SSO to use certain qualifying federal income tax credits available to the coal synfuel facility and are subject to early cancellation if the synfuel tax credits become unavailable to SSO due to a rise in the price of crude oil or otherwise. SSO has advised us that resumption of operations of the synfuel facility is dependent on the price of crude oil in the future. In anticipation of the suspension of operations at the SSO coal synfuel production facility, we will sell coal directly to SSO s synfuel customers under back up coal supply agreements, which automatically provide for the sale of our coal in the event these customers do not purchase coal synfuel from SSO. We also entered into agreements with the owners of two other coal synfuel production facilities PC Indiana Synthetic Fuel #2, L.L.C. (PCIN), related to its coal synfuel facility located at our Gibson County Coal, LLC mining complex in Gibson County, Indiana and Mt. Storm Coal Supply, LLC (Mt. Storm Coal Supply), related to its coal synfuel facility located at Virginia Electric and Power Company s Mt. Storm power station, which is adjacent to our Mettiki Coal, LLC mining complex in Garrett County, Maryland. The PCIN and Mt. Storm Coal Supply synfuel facilities currently remain in operation; however, the continued operation of these facilities cannot be assured as the operators of these facilities have similar contractual rights to suspend production due to higher oil prices. For 2006, the incremental net income benefit to us from all of its coal synfuel-related agreements is expected to be in the range of approximately $26.0 million to $28.0 million, assuming that coal pricing would not increase without the availability of synfuel. Approximately $19.8 million of the 2006 estimated incremental net income benefit was attributable to the SSO facility, of which approximately $8.0 million was realized by us prior to SSO s anticipated suspension of operations at Warrior. Pursuant to its agreement with SSO, we are not obligated to make retroactive adjustments or reimbursements if SSO s synfuel tax credits are disallowed.

We reported quarterly net income for the three months ended March 31, 2006 (the 2006 Quarter) of $48.2 million, an increase of 23.5% over the three months ended March 31, 2005 (the 2005 Quarter). Increased results for the 2006 Quarter were primarily attributable to increased sales volumes from the MC Mining complex, which returned to production following the MC Mining Fire Incident described below. During the 2006 Quarter, we continued to benefit from higher average sales prices reflecting the continuation of favorable coal markets, which benefit was partially offset by increased production costs.

We have contractual commitments for substantially all of our remaining estimated 2006 production.

In connection with the initial public offering of Alliance Holdings GP, L.P. (AHGP), Alliance Management Holdings, LLC (AMH) and AMH II, LLC (AMH II), the current owners of our managing general partner and Alliance Resource GP, LLC, our special general partner (SGP), have entered into a Contribution Agreement pursuant to which, at the closing of the initial public offering, the 1.98% general partner interest in our managing general partner, the incentive distribution rights, 15,550,628 of our common units and a 0.001% managing interest in Alliance Coal, LLC (Alliance Coal) will be contributed to AHGP. As consideration for this contribution and in accordance with the terms of the Contribution Agreement, AHGP will distribute to AMH, AMH II and SGP substantially all the proceeds from its initial public offering as well as a certain amount of its common units. In connection with the closing of the initial public offering of AHGP, we will enter into an administrative services agreement between our managing general partner, Alliance Coal, AHGP, and Alliance Resource Holdings II, Inc. (ARH II). Under the administrative services agreement, certain personnel of Alliance GP, LLC (Alliance GP) and its affiliates, including executive officers, will perform administrative and commercial services for us, AHGP and ARH II and their respective affiliates and/or alternatively, certain of our own personnel will provide administrative services to our managing general

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partners, AHGP, Alliance GP and ARH II. Concurrently, AHGP, Alliance GP, LLC (the general partner of AHGP) and our managing general partner will be joined as parties to our Omnibus Agreement, which addresses area of non-competition between AHGP and us.

RESULTS OF OPERATIONS

Three Months Ended March 31, 2006 Compared to Three Months Ended March 31, 2005

	March 31,		**March 31,**	
	2006	**2005**	**2006**	**2005**
	(in thousands)		**(per ton sold)**	
Tons sold	6,102	5,631	N/A	N/A
Tons produced	6,248	5,729	N/A	N/A
Coal sales	$ 218,212	$ 178,846	$ 35.76	$ 31.76
Operating expenses and outside purchases	$ 155,536	$ 123,510	$ 25.49	$ 21.93

Coal sales. Coal sales increased 22.0% to $218.2 million for the 2006 Quarter from $178.8 million for the 2005 Quarter. The increase of $39.4 million reflects increased sales volumes (contributing $15.0 million of the increase) and higher coal sales prices (contributing $24.4 million of the increase). Tons sold increased 8.4% to 6.1 million tons for the 2006 Quarter from 5.6 million tons for the 2005 Quarter. Tons produced increased 9.1% to 6.2 million tons for the 2006 Quarter from 5.7 million tons for the 2005 Quarter.

Operating expenses. Operating expenses increased 27.3% to $152.0 million for the 2006 Quarter from $119.4 million for the 2005 Quarter. The increase of $32.6 million resulted from an increase in operating expenses associated with additional coal sales of 471,000 tons, including the following specific factors:

Labor and benefit costs increased $12.4 million reflecting increased headcount, pay rate increases and escalating health care costs;

Material and supplies, and maintenance costs increased $10.3 million and $2.3 million, respectively, reflecting increased production and increased costs for the products and services used in the mining process;

Third party mining costs increased $2.9 million reflecting the addition of two small third party mining operations at Mettiki;

Production taxes and royalties (which are incurred as a percentage of coal sales or volumes) increased $3.8 million;

Coal supply agreement buy-out expense decreased $1.4 million;

Costs of $3.8 million associated with the purchase of tons under the settlement agreement we entered into with ICG, LLC (ICG) in November 2005. Consistent with the guidance in the Financial Accounting Standards Board s Emerging Issues Task Force No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, Pontiki s sale of coal to ICG and Alliance Coal s purchase of coal from ICG are combined. Therefore, the excess of Alliance Coal s purchase price from ICG over Pontiki s sales price to ICG is reflected as an operating expense; and

Operating expenses were reduced by $4.8 million, reflecting the net of additional operating costs incurred in the mine development process offset by revenues received for coal produced incidental with the mine development process.

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General and administrative. General and administrative expenses increased to $7.2 million for the 2006 Quarter from $5.7 million for the 2005 Quarter. The increase of $1.5 million was primarily related to higher unit-based incentive compensation expense associated with the Long-Term Incentive Plan (LTIP). Prior to our adoption of Statement of Financial Accounting Standards No. 123R, *Shared-Based Payment*, (SFAS No. 123R) effective January 1, 2006 using the modified prospective transition method, our LTIP expense was impacted by period-to-period changes in our common unit price. Our common unit price declined from $37.00 at December 31, 2004 to $32.14 at March 31, 2005, which lowered our LTIP expense for the three months ended March 31, 2005. An increase in salaries and benefits associated with additional corporate employees and additional corporate compliance costs also contributed to the increase in general & administrative expense.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of rental and service revenue to coal synfuel production facilities and Mt. Vernon Transfer Terminal transloading fees. Other sales and operating revenues increased 40.7% to $10.1 million for the 2006 Quarter from $7.2 million for the 2005 Quarter. The increase of $2.9 million was primarily attributable to $1.9 million of additional rental and service fees associated with a new third-party coal synfuel facility at the Gibson County Coal Operation, which began producing synfuel in May 2005, and $0.8 million of rent and service fees associated with increased volumes at a third-party coal synfuel facility at Warrior.

Outside purchases. The decrease in outside purchases to $3.5 million for the 2006 Quarter from $4.1 million in the 2005 Quarter was primarily attributable to not purchasing coal from a third-party supplier that experienced production difficulties in the 2006 Quarter.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $14.7 million for the 2006 Quarter from $13.6 million for the 2005 Quarter. The increase of $1.1 million as primarily attributable to additional depreciation expense associated with an increase of capital expenditures and infrastructure investments in recent years which has increased our production capacity.

Interest expense. Interest expense decreased to $2.2 million for the 2006 Quarter from $3.5 million for the 2005 Quarter. The decrease of $1.3 million was principally attributable to increased interest income earned on marketable securities which is netted against interest expense in addition to the capitalized interest of $0.4 million in the 2006 Quarter related to the development at the Elk Creek and Mountain View mines. We had no borrowings under the credit facility during the 2006 or 2005 Quarters.

Transportation revenues and expenses. Transportation revenues and expenses were comparable for the 2006 and 2005 Quarters at $10.0 million and $9.6 million, respectively. Transportation services are a pass through to our customers. Consequently, we do not realize any margin on transportation revenues.

Income before income taxes. Income before income taxes increased to $48.9 million for the 2006 Quarter from $39.8 million for the 2005 Quarter. The increase of $9.1 million was primarily attributable to increased sales volumes and higher coal prices partially offset by higher operating expenses. Results for the 2006 Quarter benefited from increased sales volumes from the MC Mining complex, which returned to production following the MC Mining Fire Incident described below. There were no unusual items included in the results for the 2006 Quarter.

Income tax expense. Income tax expense was comparable for the 2006 and 2005 Quarters at $0.8 million and $0.7 million, respectively.

Cumulative effect of accounting change. The cumulative effect of accounting change $0.1 million was attributable to the adoption of SFAS No. 123R on January 1, 2006.

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Our 2006 Quarter Segment Adjusted EBITDA increased $10.4 million, or 16.6%, to $73.0 million from 2005 Quarter Segment Adjusted EBITDA of $62.6 million. Segment Adjusted EBITDA, tons sold, coal sales, operating revenues and Adjusted Segment EBITDA Expense by segment are as follows (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005	Increase/(Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 51,311	$ 45,979	$ 5,332	11.6%
Central Appalachia	11,904	3,768	8,136	215.9%
Northern Appalachia	7,885	12,441	(4,556)	(36.6)%
Other and Corporate	1,921	411	1,510	367.4%
Total Segment Adjusted EBITDA (1)	$ 73,021	$ 62,599	$ 10,422	16.6%
Tons sold				
Illinois Basin	4,309	4,200	109	2.6%
Central Appalachia	975	543	432	79.6%
Northern Appalachia	818	888	(70)	(7.9)%
Other and Corporate				
Total tons sold	6,102	5,631	471	8.4%
Coal sales				
Illinois Basin	$ 141,314	$ 124,866	$ 16,448	13.2%
Central Appalachia	47,198	23,630	23,568	99.7%
Northern Appalachia	24,716	30,350	(5,634)	(18.6)%
Other and Corporate	4,984		4,984	
Total coal sales	$ 218,212	$ 178,846	$ 39,366	22.0%
Other sales and operating revenues				
Illinois Basin	$ 8,237	$ 5,424	$ 2,813	51.9%
Central Appalachia	238	185	53	28.6%
Northern Appalachia	553	609	(56)	(9.2)%
Other and Corporate	1,046	940	106	11.3%
Total other sales and operating revenues	$ 10,074	$ 7,158	$ 2,916	40.7%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 98,241	$ 84,311	$ 13,930	16.5%
Central Appalachia	35,532	20,047	15,485	77.2%
Northern Appalachia	17,385	18,518	(1,133)	(6.1)%
Other and Corporate	4,107	529	3,578	676.4%
Total Segment Adjusted EBITDA Expense (2)	$ 155,265	$ 123,405	$ 31,860	25.8%

(1) Segment Adjusted EBITDA is defined as net income before income tax expense (benefit), interest expense and interest income, depreciation, depletion and amortization, and general and administrative expense. Adjusted Segment EBITDA is reconciled to net income below.

(2) Segment Adjusted EBITDA Expense includes operating expenses, outside purchases and other income. Pass through transportation expenses are excluded.

Illinois Basin Segment Adjusted EBITDA for 2006 Quarter increased 11.6%, to $51.3 million from 2005 Quarter Segment Adjusted EBITDA of $46.0 million. The increase of $5.3 million was primarily attributable to increased coal sales which rose by $16.4 million, or 13.2%, to $141.3 million during 2006 as compared to $124.9 million in 2005. Increased coal sales in 2006 reflects a higher average coal sales price per ton which increased $3.07 per ton to $32.80 per ton (contributing $13.2 million of the increase in coal sales) and increased tons sold of 109,000 tons (contributing $3.2 million of the increase in coal sales). Other sales and operating revenues increased

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$2.8 million, primarily due to $1.9 million of revenues associated with the coal synfuel facility that began operating at Gibson in 2005. Total Segment Adjusted EBITDA Expense for 2006 Quarter increased 16.5% to $98.2 million from $84.3 million in 2005. On a per ton sold basis, 2006 Quarter Segment Adjusted EBITDA Expense rose to $22.80 per ton, an increase of 13.6% over the 2005 Quarter Segment Adjusted EBITDA Expense per ton of $20.07 per ton. The increase in 2006 Quarter Segment Adjusted EBITDA Expense compared to 2005 primarily reflects the impact of cost increases described above under consolidated operating expenses.

Central Appalachia Segment Adjusted EBITDA for 2006 Quarter increased $8.1 million, or 215.9%, to $11.9 million as compared to 2005 Quarter Segment Adjusted EBITDA of $3.8 million. The increase was primarily attributable to increased coal sales of $23.6 million, reflecting a higher average coal sales price per ton of $48.41 in 2006, an increase of $4.89 per ton over the 2005 average coal sales price per ton, (which contributed $4.8 million of the increase in coal sales) and increased tons sold of 432,000 tons in the 2006 Quarter, contributing $18.8 million of increase in coal sales. Segment Adjusted EBITDA Expense for 2006 Quarter increased 77.2% to $35.5 million from $20.0 million in 2005. The increase in 2006 Quarter Segment Adjusted EBITDA Expense compared to 2005 primarily reflects the impact of cost increases described above under consolidated operating expenses. However, on a per ton basis, 2006 Quarter Segment Adjusted EBITDA Expense declined $0.48 per ton reflecting an increase in production of 427,000 tons. The production increase was primarily attributable to the negative impact of the MC Mining Fire Incident on production in the 2005 Quarter.

Northern Appalachia Segment Adjusted EBITDA for 2006 Quarter decreased $4.6 million, or 36.6%, to $7.9 million as compared to 2005 Quarter Segment Adjusted EBITDA of $12.4 million. The decrease was primarily attributable to a $5.6 million reduction of coal sales reflecting a lower average sales price per ton of $3.96 to $30.22 per ton in 2006 (which contributed $3.2 million of the decrease in coal sales) and decreased tons sold of 70,000 tons (which contributed $2.4 million of the decrease in coal sales). The lower average sales price was primarily attributable to fewer tons sold into the higher priced export market during the 2006 Quarter. The increase in 2006 Quarter Segment Adjusted EBITDA Expense in 2006 compared to 2005 primarily reflects the impact of cost increases described above under consolidated operating expenses, partially offset by lower tons sold.

A reconciliation of Segment Adjusted EBITDA to net income is as follows (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Segment Adjusted EBITDA	$ 73,021	$ 62,599
General & administrative	(7,158)	(5,708)
Depreciation, depletion and amortization	(14,722)	(13,628)
Interest expense	(2,245)	(3,474)
Income taxes	(759)	(710)
Cumulative effect of accounting change	112	
Net income	$ 48,249	$ 39,079

MC Mining Mine Fire

On December 26, 2004, our MC Mining, LLC s 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 U.S. Department of Labor s Mine Safety and Health Administration (MSHA) and Kentucky Office of Mine Safety and Licensing, the four portals at the Excel No. 3 mine were temporarily capped to deprive the fire of oxygen. A series of boreholes was then drilled into the mine from the surface, and nitrogen gas and foam were injected through the boreholes 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. Once the 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. Coal production has returned to near normal levels, but continues to be adversely impacted by inefficiencies attributable to or associated with the MC Mining Fire Incident.

We maintain commercial property (including business interruption and extra expense) insurance policies with various underwriters, which policies are renewed annually in October 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). We believe such insurance coverage will cover a substantial portion of the total cost of the disruption to MC Mining s operations. However, concurrent with the renewal of our commercial property (including business interruption) insurance policies concluded on October 31, 2005, MC Mining confirmed with the current underwriters of the commercial property insurance coverage that any negotiated settlement of the losses arising from or in connection with the MC Mining Fire Incident would not exceed $40.0 million (inclusive of co-insurance and deductible amounts). Until the claim is resolved ultimately, through the claim adjustment process, settlement, or litigation, with the applicable underwriters, we can make no assurance of the amount or timing of recovery of insurance proceeds.

We made an initial estimate of certain costs primarily associated with activities relating to the suppression of the fire and the initial resumption of operations. Operating expenses for the 2004 fourth quarter were increased by $4.1 million to reflect 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.

Following the initial two submittals by us to the a representative of the underwriters of our estimate of the expenses and losses (including business interruption losses) incurred by MC Mining and other affiliates arising from or in connection with the MC Mining Fire Incident (MC Mining Insurance Claim), on September 15, 2005, we filed a third estimate of our expenses and losses, with an update through July 31 2005. Partial payments of $2.9 million and $12.2 million were received, during April 2006 and the year ended December 31, 2005, respectively, these amounts are net of the 2005 Deductibles and 2005 Co-Insurance. The accounting for these partial payments and future payments, if any, made to us by the underwriters will be subject to the accounting methodology described below. On March 23, 2006, we filed a third partial proof of loss for the period through July 31, 2005 of $4.0 million. Currently, we continue to evaluate our potential insurance recoveries under the applicable insurance policies in the following areas:

1. Fire Brigade/Extinguishing/Mine Recovery Expense; Expenses to Reduce Loss; Debris Removal Expenses; Demolition and Increased Cost of Construction; Expediting Expenses; and Extra Expenses incurred as a result of the fire - These expenses and other costs (e.g. professional fees) associated with extinguishing the fire, reducing the overall loss, demolition of certain property and removal of debris, expediting the recovery from the loss, and extra expenses that would not have been incurred by us, but for the MC Mining Fire Incident, are being expensed as incurred with related actual and/or estimated insurance recoveries recorded as they are considered to be probable, up to the amount of the actual cost incurred.

2. Damage to MC Mining mine property - The net book value of property destroyed of $154,000, was written off in the first quarter of 2005 with a corresponding amount recorded as an estimated insurance recovery, since such recovery is considered probable. Any insurance proceeds from the claims relating to the MC Mining mine property (other than amounts relating to the matters discussed in 1. above) that exceed the net book value of such damaged property are expected to result in a gain. The anticipated gain will be recorded when the MC Mining Insurance Claim is resolved and/or proceeds are received.

3. MC Mining mine business interruption losses We have submitted to a representative of the underwriters a business interruption loss analysis for the period of December 24, 2004

through July 31, 2005. Expenses associated with business interruption losses are expensed as incurred, and estimated insurance recoveries of such losses are recognized to the extent such recoveries are considered to be probable, up to the actual amount incurred. Recoveries in excess of actual costs incurred will be recorded as gains when the MC Mining Insurance Claim is resolved and/or proceeds are received.

Pursuant to the accounting methodology described above, we have recorded as an offset to operating expenses, $0.4 million and $9.2 million, during the three months ended March 31, 2006 and 2005, respectively, and $10.7 million for the year ended December 31, 2005. These amounts represent the current estimated insurance recovery of actual costs incurred, net of the 2005 Deductibles and 2005 Co-Insurance. We continue to discuss the MC Mining Insurance Claim and the determination of the total claim amount with representatives of the underwriters. The MC Mining Insurance Claim will continue to be developed as additional information becomes available and we have completed our assessment of the losses (including the methodologies associated therewith) arising from or in connection with the MC Mining Fire Incident. At this time, based on the magnitude and complexity of the MC Mining Insurance Claim, we are unable to reasonably estimate the total amount of the MC Mining Insurance Claim as well as its exposure, if any, for amounts not covered by our insurance program.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Cash provided by operating activities was $67.6 million for the 2006 Quarter compared to $28.5 million for the 2005 Quarter. The increase in cash provided by operating activities was principally attributable to a combination of a lower period-to-period increase in working capital in the 2006 Quarter compared to the 2005 Quarter and an increase in net income. Total working capital changes include a reduced use of cash attributable to accounts receivable and other receivables in the 2006 Quarter compared to the 2005 Quarter. The 2005 Quarter included a $9.3 million increase in accounts receivable related to the MC Mining Fire Incident described above and higher trade accounts receivable attributable to slow payments from certain customers.

Net cash used in investing activities was $35.0 million for the 2006 Quarter compared to $16.7 million for the 2005 Quarter. The increase is primarily attributable to an increase in capital expenditures associated with the continuing development of the Elk Creek and Mountain View mines. We are currently estimating total capital expenditures in 2006 to range from approximately $160.0 million to $175.0 million. 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 the revolving credit facility. The increase in net cash used in investing activities attributable to increased capital expenditures was partially offset by proceeds from marketable securities, net of purchases of marketable securities, which occurred during the 2006 Quarter.

Net cash used in financing activities was $21.2 million for the 2006 Quarter compared to $14.8 million for the 2005 Quarter. The increase is attributable to increased distributions to partners in the 2006 Quarter.

Capital Expenditures

Capital expenditures increased to $44.7 million in the 2006 Quarter from $16.9 million in the 2005 Quarter. See discussion of Cash Flows above concerning the increase in capital expenditures. Capital expenditures include items received but not yet paid, which is disclosed as a non-cash investing activity, purchase of property, plant and equipment in Item 1, Financial Statements (Unaudited) Condensed Consolidated Statements of Cash Flow.

Notes Offering and Credit Facility

Alliance Resource Operating Partners, L.P., our intermediate partnership, has $162.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in nine remaining equal annual installments of $18.0 million with interest payable semiannually (Senior Notes). On April 13, 2006, our intermediate partnership entered into a $100.0 million revolving credit facility (Credit Facility), which expires in 2011. The Credit Facility replaced a $85.0 million credit facility that would have expired September 2006. The interest rate on the Credit Facility is based on the London Interbank Offered Rate (LIBOR) and the financial performance of the intermediate partnership. Initially, the interest rate will be the LIBOR rate plus 0.875%. Letters of credit can be issued under the Credit Facility not to exceed $50.0 million. Outstanding letters of credit reduce amounts available under the Credit Facility. At March 31, 2006, we had letters of credit of $10.8 million outstanding under the Credit Facility. We had no borrowings outstanding under the Credit Facility at March 31, 2006.

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 exceeding $35.0 million. The Senior Notes restrictions on distributions are consistent with the Partnership Agreement and the Credit Facility limit borrowings to fund distributions to $25.0 million. We were in compliance with the covenants of both the Credit Facility and Senior Notes at March 31, 2006.

We have previously entered into and have maintained specific 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 March 31, 2006, we had $24.8 million in letters of credit outstanding under these agreements. Our special general partner guarantees these outstanding letters of credit.

RELATED PARTY TRANSACTIONS

We have continuing related party transactions with our managing general partner and our special general partner, including our special general partner s affiliates. These related party transactions relate principally to the provision of administrative services by our managing general partner, mineral and equipment leases with our special general partner and its affiliates, and guarantees from our special general partner for letters of credit.

Please read our Annual Report on Form 10-K for the year ended December 31, 2005, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations Related Party Transactions for additional information concerning the related party transactions described above.

In connection with the initial public offering of AHGP (IPO), AMH and AMH II, the current owners of our managing general partner and our special general partner, SGP, have entered into a Contribution Agreement pursuant to which, at the closing of the initial public offering, the 1.98% general partner interest in our managing general partner, the incentive distribution rights, 15,550,628 of our common units and a 0.001% managing interest in Alliance Coal will be contributed to AHGP. As consideration for this contribution and in accordance with the terms of the Contribution Agreement, AHGP will distribute to AMH, AMH II and SGP substantially all the proceeds from its initial public offering as well as a certain amount of its common units. In connection with the closing of the initial public offering of AHGP, we will enter into an administrative services agreement between our managing general partner, Alliance Coal, AHGP, and Alliance ARH II. Under the administrative services agreement, certain personnel of Alliance GP, LLC (Alliance GP) and its affiliates, including executive officers, will perform administrative and commercial services for us, AHGP and ARH II and their respective affiliates and/or alternatively, certain of our own personnel will provide administrative services to our managing general partners, AHGP, Alliance GP and ARH II. Concurrently, AHGP, Alliance GP, LLC (the general partner of AHGP) and our managing general partner will be joined as parties to our Omnibus Agreement, which addresses area of non-competition between AHGP and us.

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, Chapter 4, Paragraph 5 of ARB No. 43, 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. SFAS No. 151 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. Our adoption of SFAS No. 151 on January 1, 2006 did not have a significant impact on our consolidated financial statements.

Effective January 1, 2006, the Partnership adopted the fair value recognition provisions of SFAS No. 123R, *Shared-Based Payment* using the modified prospective transition method and, therefore, did not restate prior period results.

In March 2005, the FASB issued EITF No. 04-6, *Accounting for Stripping Costs in the Mining Industry,* and concluded that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF No. 04-6 does not address the accounting for stripping costs incurred during the pre-production phase of a mine. EITF No. 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005, with early adoption permitted. The effect of initially applying this consensus would be accounted for in a manner similar to a cumulative-effect adjustment. Since we have historically adhered to the accounting principles similar to EITF No. 04-6 in accounting for stripping costs incurred at our surface operation, our adoption of EITF No. 04-6, effective January 1, 2006 did not have a material impact on our consolidated financial statements.

OTHER

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. The transactions surrounding the IPO, which is expected to close on May 15, 2006, represent a sale or exchange of approximately 42.3% of the total interests in our capital and profits interests. We believe, and will take the position, that the transactions surrounding the IPO, together with all other common units sold within the prior 12-month period, represent a sale or exchange of 50% or more of the total interest in our capital and profits interests. The termination of the partnership will result, among other things, in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income for the year in which the termination occurs. The impact of this termination to our unitholders is reflected in the amount of taxable income we expect to be allocated to unitholders as a result of an investment in our common units. Although the amount of increase cannot be estimated because it depends upon numerous factors including the timing of the termination, the amount could be material. The termination of the partnership currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

ITEM 3. 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.

Almost all of our transactions are denominated in U.S. dollars, and as a result, we do not have material exposure to currency exchange-rate risks. At the current time, we do not have any interest rate, foreign currency exchange rate or commodity price-hedging transactions outstanding.

Borrowings under the Credit Facility are 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 at March 31, 2006.

As of March 31, 2006, the estimated fair value of the Senior Notes was approximately $174.0 million. The fair value of long-term debt is based on interest rates that we believe are currently available to us for issuance of debt with similar terms and remaining maturities. There were no other significant changes in our quantitative and qualitative disclosures about market risk as set forth in our Annual Report on Form 10-K for the year ended December 31, 2005.

ITEM 4. CONTROLS AND PROCEDURES

We maintain controls and procedures designed to ensure that we are able to collect the information we are required to disclose in the reports we file 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 this report in connection with the original filing of our Form 10-Q on May 10, 2006. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive and Chief Financial Officers. Based on an evaluation of our disclosure controls and procedures as of the end of the period covered by this report conducted by our management, with the participation of our Chief Executive and Chief Financial Officers, our Chief Executive and Chief Financial Officers believed the design and operation of these controls and procedures were effective.

Restatement of Previous Filing

In June 2006, we identified an error in the calculations of selected production expenses for the three months ended March 31, 2006 and 2005 disclosed in Note 10, Segment Information, to the condensed consolidated financial statements for the three months ended March 31, 2006 and 2005. Production taxes and royalties were inadvertently added rather than deducted from combined operating expenses and outside purchases in calculating selected production expenses for the three months ended March 31, 2006 and 2005.

Re-Evaluation of Disclosure Controls and Procedures

In connection with the restatement and the filing of this Form 10-Q/A, we re-evaluated our disclosure controls and procedures. In performing such re-evaluation of disclosure controls and procedures we considered the control failure that resulted in the error in the presentation of selected production expenses. Based on our re-evaluation, we concluded that the restatement of the corresponding footnote disclosure to the financial statements to correct the calculations of selected production expenses was the result of a significant deficiency in our internal control over financial reporting. In reaching this conclusion, we considered the fact that the incorrect calculation of selected production expenses did not affect the Condensed Consolidated Balance Sheets as of March 31, 2006 and December 31, 2005, the Condensed Consolidated Statement of Income for the three months ended March 31, 2006 and 2005 or the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2006 and 2005.

Based on that re-evaluation of our disclosure controls and procedures as of the end of the period covered by this report conducted by our management, with the participation of our Chief Executive and Chief Financial Officers, our Chief Executive and Chief Financial Officers believe that the design and operation of these controls and procedures were effective.

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Remediation of Significant Deficiency in Internal Control

The disclosure of selected production expenses was initially provided in the notes to the financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2005 (Year 2005 Form 10-K). The calculations of selected production expenses were manually prepared for the segment reporting disclosures included in both the Year 2005 Form 10-K and for the three months ended March 31, 2006 and 2005. Selected production expenses disclosed in the Year 2005 Form 10-K were properly calculated.

For the three months ended March 31, 2006 and 2005, the manual process for calculating selected production expenses was inadvertently altered and not detected during management s review. Following the initial filing of our Form 10-Q for the quarter ended March 31, 2006, the incorrect calculations of selected production expenses for the three months ended March 31, 2006 and 2005 were identified during the process of developing standard reports to be used prospectively to calculate and compile our segment reporting disclosure information, including selected production expenses. These standard reports were developed in our financial applications standard reporting tool and are now part of our standard report library. We have tested the calculations in our standard reporting tool and have verified the appropriateness of the calculations and the accuracy of the report results. Consequently, we believe that the significant deficiency in internal control over financial reporting has been remediated as of the date of this filing.

Changes in Internal Controls

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of our internal controls performed during the first quarter 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q 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 respec 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:

- increased competition in coal markets and our ability to respond to the competition;
- fluctuation in coal prices, which could adversely affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;
- deregulation of the electric utility industry or the effects of any adverse change in the 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 or breaches to existing contracts;
- customer delays or defaults in making payments;
- fluctuations in coal demand, prices and availability due to labor and transportation costs and disruptions, equipment availability, governmental regulations and other factors;
- our productivity levels and margins that we earn on our coal sales;
- greater than expected increases in raw material costs;
- greater than expected shortage of skilled labor;
- any unanticipated increases in labor costs, adverse changes in work rules, or unexpected cash payments associated with post-mine reclamation and workers compensation claims;
- any unanticipated increases in transportation costs and risk of transportation delays or interruptions;

- greater than expected environmental regulation, costs and liabilities;
- a variety of operational, geologic, permitting, labor and weather-related factors;
- risks associated with major mine-related accidents, such as mine fires, or interruptions;
- results of litigation;
- difficulty maintaining our surety bonds for mine reclamation as well as workers compensation and black lung benefits;
- a loss or reduction of the direct or indirect benefit from certain state and federal tax credits, including non-conventional source fuel tax credits; and
- difficulty obtaining commercial property insurance, and risks associated with our participation (excluding any applicable deductible) in the 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 Quarterly Report on Form 10-Q;
- 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 persons acting on our behalf.

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PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The information in Note 2. Contingencies to the Unaudited Condensed Consolidated Financial Statements included in Item 1, Financial Statements (Unaudited) of this Quarterly Report on Form 10-Q herein is hereby incorporated by reference. See also Item 3, Legal Proceedings in the Annual Report on Form 10-K for the year ended December 31, 2005.

On April 24, 2006, we were served with a complaint from Mr. Ned Comer, et al., who we refer to as the plaintiffs, alleging that approximately 40 oil and coal companies, including us, which we refer to as the defendants, are liable to the plaintiffs for tortiously causing damage to plaintiffs property in Mississippi. The plaintiffs allege that the defendants greenhouse gas emissions caused global warming and resulted in the increase in the destructive capacity of Hurricane Katrina. We believe this complaint is without merit and does not believe that this complaint will have a material adverse effect on our business, financial position or results of operations.

ITEM 1A. RISK FACTORS

There were no significant changes in our risk factors as set forth in our Annual Report on Form 10-K for the year ended December 31, 2005 except as follows:

On April 19, 2006, we received a letter from the managing member of Synfuel Solutions Operating, LLC (SSO), which stated that effective April 23, 2006, due to the increase in the wellhead price of domestic crude oil, SSO has elected to exercise its contractual right to suspend until further notice operation of its coal synfuel production facility located at our Warrior Coal, LLC (Warrior) mining complex in Hopkins County, Kentucky. We receive fees from coal sales, rental, marketing and other services provided to SSO pursuant to various long-term agreements associated with the coal synfuel facility located at Warrior. SSO has advised us that resumption of operations of the synfuel facility is dependent on the price of crude oil in the future.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

None.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

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 June 22, 2006, 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 June 22, 2006, 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 June 22, 2006, 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 June 22, 2006, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith.

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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 June 22, 2006.

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