ALLIANCE RESOURCE PARTNERS LP
Form 10-Q
August 09, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 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 400, 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 August 9, 2006, 36,426,306 Common Units are outstanding.

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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)

	June 30, 2006	December 31, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 48,600	$ 32,054
Trade receivables, net	77,706	94,495
Other receivables	4,642	2,330
Due from affiliates	115	
Marketable securities	24,477	49,242
Inventories	35,902	17,270
Advance royalties	2,952	2,952
Prepaid expenses and other assets	3,801	8,934
Total current assets	198,195	207,277
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment at cost	726,189	635,086
Less accumulated depreciation, depletion and amortization	(357,372)	(330,672)
Total property, plant and equipment	368,817	304,414
OTHER ASSETS:		
Advance royalties	22,905	16,328
Other long-term assets	5,085	4,668
Total other assets	27,990	20,996
TOTAL ASSETS	$ 595,002	$ 532,687
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 53,806	$ 53,473
Due to affiliates	1,540	8,795
Accrued taxes other than income taxes	13,806	13,177
Accrued payroll and related expenses	12,810	12,466
Accrued pension benefit	9,263	7,588
Accrued interest	4,787	4,855
Workers compensation and pneumoconiosis benefits	7,628	7,740
Other current liabilities	9,546	5,120
Current maturities, long-term debt	18,000	18,000

Total current liabilities	131,186	131,214
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	144,000	144,000
Pneumoconiosis benefits	24,750	23,293
Workers compensation	33,246	30,050
Reclamation and mine closing	42,484	38,716
Due to affiliates	1,516	6,940
Minority interest	957	
Other liabilities	6,369	2,697
Total long-term liabilities	253,322	245,696
Total liabilities	384,508	376,910
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Limited Partners - Common Unitholders 36,426,306 units outstanding	513,386	461,068
General Partners deficit	(295,937)	(298,270)
Unrealized loss on marketable securities	(2)	(68)
Minimum pension liability	(6,953)	(6,953)
Total Partners capital	210,494	155,777
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 595,002	$ 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 June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
SALES AND OPERATING REVENUES:				
Coal sales	$ 205,513	$ 192,127	$ 423,725	$ 370,973
Transportation revenues	8,956	8,384	18,990	18,007
Other sales and operating revenues	6,835	8,205	16,909	15,363
Total revenues	221,304	208,716	459,624	404,343
EXPENSES:				
Operating expenses	140,877	128,125	292,887	247,518
Transportation expenses	8,956	8,384	18,990	18,007
Outside purchases	4,705	3,392	8,231	7,509
General and administrative	7,091	10,547	14,249	16,255
Depreciation, depletion and amortization	16,288	13,396	31,010	27,024
Total operating expenses	177,917	163,844	365,367	316,313
INCOME FROM OPERATIONS	43,387	44,872	94,257	88,030
Interest expense (net of interest capitalized for the three and six months ended June 30, 2006 of $268 and $691, respectively)	(3,439)	(3,953)	(6,588)	(7,900)
Interest income	909	583	1,813	1,056
Other income	197	119	468	224
INCOME BEFORE INCOME TAXES, CUMULATIVE EFFECT OF ACCOUNTING CHANGE AND MINORITY INTEREST	41,054	41,621	89,950	81,410
INCOME TAX EXPENSE	547	829	1,306	1,539
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE AND MINORITY INTEREST	40,507	40,792	88,644	79,871
CUMULATIVE EFFECT OF ACCOUNTING CHANGE			112	
MINORITY INTEREST	43		43	
NET INCOME	$ 40,550	$ 40,792	$ 88,799	$ 79,871
GENERAL PARTNERS INTEREST IN NET INCOME	$ 6,090	$ 3,025	$ 10,934	$ 4,709
LIMITED PARTNERS INTEREST IN NET INCOME	$ 34,460	$ 37,767	$ 77,865	$ 75,162
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.73	$ 0.73	$ 1.56	$ 1.44
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.72	$ 0.72	$ 1.55	$ 1.41

DISTRIBUTIONS PAID PER COMMON AND SUBORDINATED UNIT	$ 0.46	$ 0.375	$ 0.92	$ 0.75
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING-BASIC	36,426,306	36,260,880	36,426,306	36,260,880
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING-DILUTED	36,797,407	36,995,172	36,780,300	36,994,006

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)

	Six Months Ended June 30,	
	2006	**2005**
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 128,820	$ 96,396
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(92,017)	(47,306)
Changes in accounts payable and accrued liabilities	(1,786)	4,265
Proceeds from sale of property, plant and equipment	510	193
Purchase of marketable securities	(19,187)	(24,373)
Proceeds from marketable securities	44,018	24,399
Payment for purchase of River View Coal, LLC	(1,648)	
Net cash used in investing activities	(70,110)	(42,822)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payment of debt issuance cost	(690)	
Equity contribution received by Mid-America Carbonates, LLC	1,000	
Distributions to Partners	(42,474)	(29,594)
Net cash used in financing activities	(42,164)	(29,594)
NET CHANGE IN CASH AND CASH EQUIVALENTS	16,546	23,980
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	32,054	31,177
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 48,600	$ 55,157
CASH PAID FOR:		
Interest	$ 6,934	$ 7,613
Income taxes to taxing authorities	$ 1,900	$ 1,900
NON-CASH INVESTING ACTIVITY		
Purchase of property, plant and equipment	$ 7,577	$ 8,051

See notes to condensed consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(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. ARH was formerly owned by management of the Partnership. In June 2006, ARH and its parent company became wholly-owned, directly and indirectly, by Joseph W. Craft, III, the Partnership s President and Chief Executive Officer.

The Partnership is managed by Alliance Resource Management GP, LLC, (the Managing GP). Alliance Holdings GP, L.P. (AHGP) is a Delaware limited partnership that was formed to own and become the controlling member of the Managing GP. AHGP completed its initial public offering (IPO) on May 15, 2006. Upon the closing of the IPO, AHGP owns directly and indirectly 100% of the members interest of the Managing GP, a 0.001% managing interest in Alliance Coal, LLC, the operating subsidiary of the Partnership, the incentive distribution rights in the Partnership and 15,550,628 common units of the Partnership.

The accompanying condensed consolidated financial statements include the accounts and operations of the Partnership and present the financial position as of June 30, 2006 and December 31, 2005, results of operations for the three months and six months ended June 30, 2006 and 2005 and cash flows for the six months ended June 30, 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. Currently, the Partnership is not engaged in any litigation that we believe is material to the Partnership s operations, including without limitation, any litigation relating to any of the Partnership s long-term supply contracts or under the various environmental protection statutes to which the

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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 any litigation 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 insurance claims history in the underground coal mining industry and the Partnership s recent insurance claims history (e.g., MC Mining Fire Incident, and Dotiki Fire Incident). As a result, the Partnership has 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.

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 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 243,000 tons were purchased and sold at a profit during 2005 and the six months ended June 30, 2006, respectively, and the remaining 586,000 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.

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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.

In June 2006, Alliance Resource Operating Partners, L.P. (Intermediate Partnership) entered into a guarantee agreement in which it guaranteed the performance of a third party with respect to an agreement to purchase electricity. The term of the guarantee is the earlier of January 31, 2007 or the date the agreement to purchase electricity is terminated. Under the terms of the guarantee, if the third party does not fulfill its payment obligation under the agreement to purchase electricity, the Intermediate Partnership is liable for the amounts not paid by the third party. If the Partnership were to become liable, the maximum amount of potential future payments is $2.0 million at June 30, 2006. The fair value of the guarantee is approximately $30,000 at June 30, 2006.

3. ACQUISITIONS

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. 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.

In April 2006, the Partnership acquired 100% of the membership interest in River View Coal, LLC (River View) for approximately $1.65 million from ARH. River View controls through a coal lease agreement approximately 89.7 million tons of high sulfur coal reserves and directly owns approximately 9.6 million tons of high sulfur coal reserves in the Kentucky No. 7, No. 9 and No. 11 coal seams. Under the terms of the coal lease agreements, River View paid $1.0 million in minimum royalty payments in 2005 and must pay a minimum of $250,000 in royalties per year thereafter. River View had the right to purchase certain assets, including coal reserves, surface properties, facilities and permits, from the lessor for $4.15 million plus an overriding royalty on all coal mined and sold by River View from certain of its other leased properties. In April 2006, River View purchased such assets and assumed reclamation liabilities of $2.9 million from the lessor.

The Tunnel Ridge and River View transactions described above were related-party transactions and, as such, were reviewed by the Board of Directors of 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 and River View acquisitions as fair and reasonable to the Partnership and its limited partners. Because the Tunnel Ridge and River View acquisitions were between entities under common control, they have been accounted for at historical cost.

4. 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

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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 $4.0 million and $12.2 million were received during the six months ended June 30, 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

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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 $10.3 million, during the six months ended June 30, 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 Financial Accounting Standards Board (FASB) issued Emerging Issues Task Force (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. A reconciliation of net

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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 June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Net income	$ 40,550	$ 40,792	$ 88,799	$ 79,871
Adjustments:				
General partners priority distributions	(5,387)	(2,254)	(9,345)	(3,175)
General partners 2% equity ownership	(703)	(771)	(1,589)	(1,534)
Limited partners interest in net income	$ 34,460	$ 37,767	$ 77,865	$ 75,162
Additional earnings allocation to general partners	(7,958)	(11,172)	(21,010)	(22,827)
Net income available to limited partners under EITF No. 03-6	$ 26,502	$ 26,595	$ 56,855	$ 52,335
Weighted average limited partner units basic	36,426	36,261	36,426	36,261
Basic net income per limited partner unit	$ 0.73	$ 0.73	$ 1.56	$ 1.44
Weighted average limited partner units basic	36,426	36,261	36,426	36,261
Units contingently issuable:				
Restricted units for Long-Term Incentive Plan	219	597	203	596
Directors compensation units	41	37	41	37
Supplemental Executive Retirement Plan	111	100	110	100
Weighted average limited partner units, assuming dilutive effect of restricted units	36,797	36,995	36,780	36,994
Diluted net income per limited partner unit	$ 0.72	$ 0.72	$ 1.55	$ 1.41

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 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 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 Long-Term Incentive Plan (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 of the Board of Directors of the Managing GP. Grants are made either of

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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 an affiliate 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 income tax 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. For the three months ended June 30, 2006, an additional 2,125 units were granted which will vest January 1, 2009. As of June 30, 2006, 12,940 outstanding LTIP grants have been forfeited. During the three and six months ended June 30, 2006 and 2005 the Managing GP charged the Partnership approximately $869,000, $3,486,000, $1,929,000 and $3,837,000, respectively, attributable to the LTIP.

Effective January 1, 2006, the Partnership adopted the fair value recognition provisions of Statement of Financial Accounting Standards (SFAS) 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

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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 upon adoption of SFAS No. 123R on January 1, 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 six months ended June 30, 2006 is as follows:

Non-vested grants at January 1, 2006	316,270
Granted	87,400
Vested	
Forfeited	(9,250)
Non-vested grants at June 30, 2006	394,420

As of June 30, 2006, there was $5,621,000 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 1.2 years. As of June 30, 2006, the intrinsic value of the non-vested LTIP grants was $13,532,340.

The total obligation associated with the LTIP as of June 30, 2006 was $8,326,000 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 2005 disclosure requirements of Statement of Financial Accounting Standards (SFAS) No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, and amendment of SFAS No. 123, *Accounting for Stock-Based Compensation*, the following table demonstrates that compensation costs 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):

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	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
Net income, as reported	$ 40,792	$ 79,871
Add: compensation expenses related to Long-Term Incentive Plan units included in reported net income	3,532	4,021
Deduct: compensation expense related to Long-Term Incentive Plan units determined under fair value method for all awards	(3,532)	(4,021)
Net income, pro forma	$ 40,792	$ 79,871
General partners interest in net income, pro forma	$ 3,025	$ 4,709
Limited partners interest in net income, pro forma	$ 37,767	$ 75,162
Earnings per limited partner unit:		
Basic, as reported	$ 0.73	$ 1.44
Basic, pro forma	$ 0.73	$ 1.44
Diluted, as reported	$ 0.72	$ 1.41
Diluted, pro forma	$ 0.72	$ 1.41

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 June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Service cost	$ 829	$ 812	$ 1,658	$ 1,625
Interest cost	487	418	974	835
Expected return on plan assets	(567)	(482)	(1,134)	(965)
Prior service cost	11	12	22	25
Net loss	78	50	156	100
	$ 838	$ 810	$ 1,676	$ 1,620

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 June 30, 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 Mountain View 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.

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9. NEW ACCOUNTING STANDARDS

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs* (SFAS No. 151). 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* (EITF No. 04-6), 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.

In June 2006, the FASB issued FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. The interpretation prescribes a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The provisions of FIN 48 are effective for fiscal years beginning after December 31, 2006. The Partnership is currently in the process of assessing the provisions of FIN 48, but does not expect the adoption of FIN 48 to have a material impact on its consolidated financial statements.

10. COMPREHENSIVE INCOME

The following table summarizes the effect of our marketable securities available for sale in other comprehensive income for the three and six months ended June 30, 2006 and 2005, respectively, (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Net income	$ 40,550	$ 40,792	$ 88,799	$ 79,871
Unrealized gain (loss)	50	56	66	(35)
Comprehensive income	$ 40,600	$ 40,848	$ 88,865	$ 79,836

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Comprehensive income differs from net income by the amount of unrealized gain or loss resulting from valuation changes of the Partnership s marketable securities available for sale.

11. SEGMENT INFORMATION

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, Elk Creek, Pattiki, River View 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 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 River View, Gibson South, Tunnel Ridge and Penn Ridge properties for future mine development.

Operating segment results for the three months and six months ended June 30, 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 June 30, 2006 were as follows:					
Total revenues	$ 144,238	$ 47,955	$ 25,083	$ 4,028	$ 221,304
Selected production expenses (2)	77,269	30,574	13,175	2,938	123,956
Segment Adjusted EBITDA (3)	47,385	11,743	6,865	970	66,963
Capital expenditures (4)	29,901	6,413	5,477	5,512	47,303
Operating segment results for the three months ended June 30, 2005 were as follows:					
Total revenues	$ 138,315	$ 41,700	$ 27,871	$ 830	$ 208,716
Selected production expenses (2)	72,865	23,294	13,870	271	110,300
Segment Adjusted EBITDA (3)	46,513	12,952	9,079	390	68,934
Capital expenditures (4)	18,308	6,260	5,538	286	30,392

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	Illinois Basin	Central Appalachia	Northern Appalachia	Other and Corporate (1)	Consolidated
			(in thousands)		
Operating segment results for the six months ended June 30, 2006 were as follows:					
Total revenues	$ 299,585	$ 96,124	$ 53,387	$ 10,528	$ 459,624
Selected production expenses (2)	159,907	61,150	27,849	6,859	255,765
Segment Adjusted EBITDA (3)	98,696	23,647	14,750	2,891	139,984
Total assets	320,639	90,646	94,085	89,632	595,002
Capital expenditures (4)	59,461	10,218	13,651	8,687	92,017
Operating segment results for the six months ended June 30, 2005 were as follows:					
Total revenues	$ 274,607	$ 66,140	$ 61,826	$ 1,770	$ 404,343
Selected production expenses (2)	142,897	40,910	29,448	632	213,887
Segment Adjusted EBITDA (3)	92,492	16,720	21,520	801	131,533
Total assets	235,260	82,895	61,032	109,525	488,712
Capital expenditures (4)	29,612	9,488	7,688	518	47,306

(1) Total Revenues included in the Other and Corporate column are principally comprised of Mt. Vernon Transfer Terminal transloading revenues, administrative service revenue from affiliates and brokerage coal sales.

(2) Selected production expenses is comprised of operating expenses and outside purchases (as reflected in the condensed consolidated statements of income), excluding production taxes and royalties that are incurred as a percentage of coal sales or volumes.

(3) Segment Adjusted EBITDA is defined as net income before income taxes, cumulative effect of accounting change and minority interest, interest expense and interest income, depreciation, depletion and amortization, and general and administrative expense. Segment Adjusted EBITDA is reconciled to net income below.

(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 condensed consolidated statements of cash flows. Capital expenditures do not include business acquisitions separately reported in the condensed consolidated statements of cash flows.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in thousands)			
Reconciliation of Segment Adjusted EBITDA to net income:				
Segment Adjusted EBITDA	$ 66,963	$ 68,934	$ 139,984	$ 131,533
General & administrative	(7,091)	(10,547)	(14,249)	(16,255)
Depreciation, depletion and amortization	(16,288)	(13,396)	(31,010)	(27,024)
Interest expense, net	(2,530)	(3,370)	(4,775)	(6,844)
Income taxes	(547)	(829)	(1,306)	(1,539)
Cumulative effect of accounting change			112	
Minority interest	43		43	
Net income	$ 40,550	$ 40,792	$ 88,799	$ 79,871
Reconciliation of Selected Production Expenses to Combined Operating Expenses and Outside Purchases:				
Selected production expenses	$ 123,956	$ 110,300	$ 255,765	$ 213,887
Production taxes and royalties	21,626	21,217	45,353	41,140
Combined operating expenses and outside purchases	$ 145,582	$ 131,517	$ 301,118	$ 255,027

12. MINORITY INTEREST

In March 2006, White County Coal, LLC (White County Coal), a subsidiary of the Partnership, and Alexander J. House (House) entered into a Limited Liability Company Agreement to form Mid-America Carbonates, LLC (MAC). MAC was formed to engage in the development and operation of a rock dust mill. The main purpose of the rock dust mill will be to manufacture and sell rock dust. In coal mining, rock dust normally consists of finely milled limestone, which is applied to haulage ways and mine entries or corridors in such quantities that the combination of coal dust, rock dust and other dust forms an incombustible content. MAC and Alliance Coal, LLC (Alliance Coal) have entered into a six year Rock Dust Supply Agreement in which MAC will supply the greater of 50,000 tons or 70% of the aggregate amount of rock dust used by Alliance Coal s subsidiaries located in the Illinois Basin. For the first three years of the contract, Alliance Coal s subsidiary will purchase the rock dust at 125% of MAC s actual production cost. Any rock dust tonnage purchased above 70% used by the Alliance Coal s subsidiary in the Illinois Basin will be priced at the prevailing market rate. After three years, the price paid by Alliance Coal mines to MAC will reopen to market.

White County Coal s initial investment was $1.0 million in exchange for a 50% equity interest in MAC. The Partnership consolidates MAC s financial results in accordance with FASB Interpretation No. 46R (FIN 46R). Based on the guidance in FIN 46R, the Partnership concluded that MAC is a variable interest entity and that the Partnership is the primary beneficiary. House s equity ownership in the net assets of MAC was $957,000 as of June 30, 2006, which is recorded as minority interest on the Partnership s condensed consolidated balance sheet.

13. SUBSEQUENT EVENTS

On July 27, 2006, the Board of Directors of the Managing GP adopted Amendment No. 1 to the Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., which addresses certain special allocation provisions with respect to capital contributions.

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On July 31, 2006, the Partnership declared a quarterly distribution for the quarter ended June 30, 2006, of $0.50 per unit, totaling approximately $24.0 million (which includes the Managing GP s incentive distributions), on all its common units outstanding, payable on August 14, 2006 to all unitholders of record as of August 7, 2006.

Also on July 31, 2006, the Partnership received notice from Synfuel Solutions Operating, LLC (SSO) that due to the increase in the wellhead price of domestic crude oil, SSO was exercising 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 located near Madisonville, 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.

During the suspension of operations at the SSO coal synfuel production facility, the Partnership sells coal directly to the SSO synfuel customers under back-up coal supply agreements, which automatically provides for the sale of its coal in the event these customers do not purchase coal synfuel from SSO. SSO has advised the Partnership that future operation of the synfuel production facility is dependent on the future price of crude oil. Pursuant to the Partnership s agreement with SSO, the Partnership is not obligated to make retroactive adjustments or reimbursements if SSO s synfuel tax credits are disallowed.

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, and Maryland, and we are developing the Mountain View mine in West Virginia, which will replace our existing Mettiki longwall mining operation in Maryland that will deplete its reserves during the fourth quarter of this year.

We reported quarterly net income for the three months ended June 30, 2006 (the 2006 Quarter) of $40.6 million compared to $40.8 million for the three months ended June 30, 2005 (the 2005 Quarter). Our performance for the quarter benefited from increased coal production as well as higher average coal sales prices which were offset by higher operating expenses and a slight decrease in tons sold. We have contractual commitments for substantially all of our remaining estimated 2006 production.

We have entered into agreements with the owners of three coal synfuel production facilities - Synfuel Solutions Operating, LLC (SSO), related to its coal synfuel facility located at our Warrior Coal, LLC (Warrior) mining complex in Hopkins County, Kentucky; PC Indiana Synthetic Fuel #2, L.L.C. (PCIN), related to its coal synfuel facility located at our Gibson County Coal, LLC (Gibson) 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 (Mettiki) mining complex in Garrett County, Maryland. SSO, PCIN, and Mt. Storm Coal Supply are collectively referred to below as Coal Synfuel Owners.

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We receive revenues from coal sales, rental, marketing and other services provided to the Coal Synfuel Owners pursuant to various long-term agreements associated with their respective coal synfuel facilities. Each of these agreements, which expire on December 31, 2007, are dependent on the ability of the Coal Synfuel Owners to use certain qualifying federal income tax credits available to their respective coal synfuel facilities and are subject to early cancellation if the synfuel tax credits become unavailable due to a rise in the price of domestic crude oil or otherwise.

We received notice from PCIN on May 11, 2006, Mt. Storm Coal Supply on July 18, 2006, and SSO on July 31, 2006, that due to the increase in the wellhead price of domestic crude oil, the operation of their respective synfuel operations were suspended until further notice. Each of the Coal Synfuel Owners has advised us that future operation of their respective synfuel facilities is dependent on the future price of crude oil. During the suspension of operations at the coal synfuel production facilities located at Warrior, Gibson and Mettiki, respectively, we sell coal directly to the Coal Synfuel Owners 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.

In anticipation of the price of domestic crude oil remaining at historically high levels, for planning and forecasting purposes, we have assumed no substantial economic benefit associated with the Coal Synfuel Owners synfuel production facilities through the remainder of 2006. For comparison purposes, we realized incremental net income benefits from the combination of the various coal synfuel arrangements in the second half of 2005 of approximately $11.9 million. Pursuant to our agreements with the Coal Synfuel Owners, we are not obligated to make retroactive adjustments or reimbursements if synfuel credits are disallowed.

In connection with the initial public offering (IPO) of Alliance Holdings GP, L.P. (AHGP), Alliance Management Holdings, LLC (AMH) and AMH II, LLC (AMH II), the previous owners of our managing general partner and Alliance Resource GP, LLC, our special general partner, entered into a Contribution Agreement pursuant to which, upon closing of the IPO, AHGP owns, directly and indirectly, 100% of the members interest in Alliance Resource Management GP, LLC (our managing general partner), a 0.001% managing interest in Alliance Coal, LLC (Alliance Coal), our operating subsidiary, the incentive distribution rights and 15,550,628 of our common units. As consideration for this contribution and in accordance with the terms of the Contribution Agreement, AHGP distributed to AMH, AMH II and our special general partner substantially all the proceeds from its IPO as well as 79.1% of its common units. Our special general partner and its parent, Alliance Resource Holdings, Inc. (ARH), were formally owned by our management. In June 2006, ARH and its parent company became wholly-owned, directly and indirectly, by Joseph W. Craft, III, our President and Chief Executive Officer.

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RESULTS OF OPERATIONS

Three Months Ended June 30, 2006 Compared to Three Months Ended June 30, 2005

	June 30,		June 30,	
	2006	2005	2006	2005
	(in thousands)		(per ton sold)	
Tons sold	5,570	5,757	N/A	N/A
Tons produced	5,802	5,642	N/A	N/A
Coal sales	$ 205,513	$ 192,127	$ 36.90	$ 33.37
Operating expenses and outside purchases	$ 145,582	$ 131,517	$ 26.14	$ 22.84

Coal sales. Coal sales for the 2006 Quarter increased 7.0% to $205.5 million from $192.1 million for the 2005 Quarter. The increase of $13.4 million is a result of higher coal sales prices (contributing to $19.6 million of the increase) reflecting continued strength in our coal markets partially offset by a decrease in tons sold (resulting in a $6.2 million decrease). Tons sold were 5.6 million and 5.8 million for the 2006 and 2005 Quarters, respectively. Tons produced increased 2.8% to 5.8 million tons for the 2006 Quarter from 5.6 million for the 2005 Quarter.

Operating expenses. Operating expenses increased 10.0% to $ 140.9 million for the 2006 Quarter from $128.1 million for the 2005 Quarter. The increase of $12.8 million resulted from higher operating expenses due to the following specific factors, partially offset by decreased coal sales volumes of 187,000 tons:

Labor and benefit costs increased $5.1 million reflecting increased headcount, pay rate increases and escalating health care costs;

Material and supplies costs increased $6.2 million reflecting increased costs for certain products and services used in the mining process;

Third-party mining costs increased $1.1 million reflecting increased production at two small third-party mining operations at Mettiki;

Production taxes and royalties (which are incurred as a percentage of coal sales or volumes) increased $0.4 million;

Property insurance costs increased $1.3 million;

Costs of $2.4 million in the 2006 Quarter were 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 (FASB) Emerging Issues Task Force (EITF) 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 reported as an operating expense;

The 2006 Quarter operating expenses were decreased by $2.4 million, reflecting the net of additional costs incurred in the mine development process offset by revenues received for coal produced incidental with the mine development process; and

The 2005 Quarter operating expenses included $2.8 million of additional expense associated with the Pattiki Vertical Belt Incident.

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General and administrative. General and administrative expenses decreased to $7.1 million for the 2006 Quarter compared to $10.5 million for the 2005 Quarter. The decrease of $3.4 million was primarily attributable to a reduction in unit-based incentive compensation expense associated with the Long-Term Incentive Plan (LTIP) and Supplemental Executive Retirement Plan in addition to the Short-Term Incentive Plan (STIP). Prior to our adoption of Statement of Financial Accounting Standards (SFAS) No. 123R, *Shared-Based Payment*, 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.

Other sales and operating revenues. Other sales and operating revenues is principally comprised of service fees from coal synfuel production facilities, Mt. Vernon Transfer Terminal transloading revenues and administrative service revenue from affiliates. Other sales and operating revenues decreased 16.7% to $6.8 million for the 2006 Quarter from $8.2 million for the 2005 Quarter. The decrease of $1.4 million is primarily attributable to a reduction in rental and service fees associated with decreased volumes at third-party coal synfuel facilities. Please read Item 2. Summary above for a discussion regarding the suspension of third-party coal synfuel facilities.

Outside purchases. Outside purchases increased to $4.7 million for the 2006 Quarter from $3.4 million in the 2005 Quarter. The increase of $1.3 million was primarily attributable to an increase in outside purchases at our Central and Northern Appalachia operations to supply new market opportunities, partially offset by lower outside purchases in our Illinois Basin operations.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $16.3 million for the 2006 Quarter from $13.4 million for the 2005 Quarter. The increase of $2.9 million is primarily attributable to additional depreciation expense associated with an increase of capital expenditures, particularly Elk Creek, Mountain View and Van Lear operations and infrastructure investments in recent years which have increased our production capacity.

Interest expense. Interest expense, net of capitalized interest, decreased to $3.4 million for the 2006 Quarter from $4.0 million for the 2005 Quarter. The decrease of $0.6 million is principally attributable to the capitalization of interest expense related to capital projects and/or mine development costs at Elk Creek, Pontiki, Gibson and Mountain View mine in addition to reduced interest expense associated with the August 2005 scheduled principal payment of $18.0 million on our senior notes. We had no borrowings under the credit facility during the 2006 Quarter.

Interest income. Interest income increased to $0.9 million for the 2006 Quarter from $0.6 million for the 2005 Quarter. The increase of $0.3 million resulted from increased interest income earned on marketable securities.

Transportation revenues and expenses. Transportation revenues and expenses increased to $9.0 million for the 2006 Quarter compared to $8.4 million for the 2005 Quarter. The increase of $0.6 million was primarily attributable to higher coal sales volumes for which we arrange transportation. The cost of transportation services are passed through to our customers. Consequently, we do not realize any margin on transportation revenues.

Income before income taxes, cumulative effect of accounting change and minority interest. Income before income taxes, cumulative effect of accounting change and minority interest was comparable for both the 2006 and 2005 Quarters at $41.1 million and $41.6 million, respectively, and reflects the impact of the changes in revenues and expenses described above.

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Income tax expense. Income tax expense decreased to $0.5 million for the 2006 Quarter from $0.8 million for the 2005 Quarter resulting from decreased volumes at third-party coal synfuel facilities.

Minority interest. In March 2006 our subsidiary, White County Coal, LLC (White County Coal) and Alexander J. House (House) entered into a Limited Liability Company Agreement to form Mid-America Carbonates, LLC (MAC). MAC was formed to engage in the development and operation of a rock dust mill. The main purpose of the rock dust mill will be to manufacture and sell rock dust. In coal mining, rock dust normally consists of finely milled limestone, which is applied to haulage ways and mine entries or corridors in such quantities that the combination of coal dust, rock dust and other dust forms an incombustible content. We consolidate MAC s financial results in accordance with FASB Interpretation No. 46R (FIN 46R). Based on the guidance in FIN 46R, we concluded that MAC is a variable interest entity and that we are the primary beneficiary. House s portion of MAC s net loss was $43,000 for the 2006 Quarter and is recorded as minority interest on our condensed consolidated income statement.

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Our 2006 Quarter Segment Adjusted EBITDA decreased $2.0 million, or 2.9%, to $67.0 million from 2005 Quarter Segment Adjusted EBITDA of $69.0 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 June 30,			
	2006	2005	Increase/(Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 47,385	$ 46,513	$ 872	1.9%
Central Appalachia	11,743	12,952	(1,209)	(9.3)%
Northern Appalachia	6,865	9,079	(2,214)	(24.4)%
Other and Corporate	970	390	580	148.7%
Total Segment Adjusted EBITDA (1)	$ 66,963	$ 68,934	$ (1,971)	(2.9)%
Tons sold				
Illinois Basin	3,923	4,090	(167)	(4.1)%
Central Appalachia	906	866	40	4.6%
Northern Appalachia	741	801	(60)	(7.5)%
Other and Corporate				
Total tons sold	5,570	5,757	(187)	(3.2)%
Coal sales				
Illinois Basin	$ 133,439	$ 126,585	$ 6,854	5.4%
Central Appalachia	47,369	40,784	6,585	16.1%
Northern Appalachia	21,861	24,758	(2,897)	(11.7)%
Other and Corporate	2,844		2,844	100.0%
Total coal sales	$ 205,513	$ 192,127	$ 13,386	7.0%
Other sales and operating revenues				
Illinois Basin	$ 5,149	$ 6,818	$ (1,669)	(24.5)%
Central Appalachia		1	(1)	(100.0)%
Northern Appalachia	500	556	(56)	(10.1)%
Other and Corporate	1,186	830	356	42.9%
Total other sales and operating revenues	$ 6,835	$ 8,205	$ (1,370)	(16.7)%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 91,203	$ 86,891	$ 4,312	5.0.%
Central Appalachia	35,627	27,833	7,794	28.0%
Northern Appalachia	15,495	16,234	(739)	(4.6)%
Other and Corporate	3,060	440	2,620	595.5%
Total Segment Adjusted EBITDA Expense (2)	$ 145,385	$ 131,398	$ 13,987	10.6%

(1) Segment Adjusted EBITDA is defined as net income before income taxes, cumulative effect of accounting change and minority interest, interest expense and interest income, depreciation, depletion and amortization, and general and administrative expense. Segment Adjusted 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.

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Illinois Basin Segment Adjusted EBITDA for the 2006 Quarter increased 1.9%, to $47.4 million from the 2005 Quarter Segment Adjusted EBITDA of $46.5 million. The increase of $0.9 million was primarily attributable to increased coal sales which rose by $6.9 million, or 5.4%, to $133.4 million in the 2006 Quarter as compared to $126.6 million in the 2005 Quarter. Increased coal sales in the 2006 Quarter reflects a higher average coal sales price per ton which increased $3.06 per ton to $34.01 per ton. Other sales and operating revenues decreased $1.7 million, primarily due to a reduction in rental and service fees associated with decreased volumes at third-party coal synfuel facilities. Segment Adjusted EBITDA Expense for the 2006 Quarter increased 5.0% to $91.2 million from $86.9 million in the 2005 Quarter. On a per ton sold basis, 2006 Quarter Segment Adjusted EBITDA Expense rose to $23.25 per ton, an increase of 9.5% over the 2005 Quarter Segment Adjusted EBITDA Expense per ton of $21.24 per ton. The increase in the 2006 Quarter Segment Adjusted EBITDA Expense compared to the 2005 Quarter primarily reflects the impact of cost increases described above under consolidated operating expenses. Additionally, Illinois Basin costs have been negatively impacted by high cost production at the Elk Creek mine which has emerged from development during the 2006 Quarter, but has not yet reached full production capacity.

Central Appalachia Segment Adjusted EBITDA for the 2006 Quarter decreased $1.2 million, or 9.3%, to $11.7 million as compared to the 2005 Quarter Segment Adjusted EBITDA of $12.9 million. The decrease was primarily attributable to cost increases described above under consolidated operating expenses. Additionally, Central Appalachia costs have been negatively impacted by high cost production from the Pontiki Van Lear mine which has emerged from development during the fourth quarter of 2005, but has not yet reached full production capacity. The decrease in Segment Adjusted EBITDA was partially offset by increased coal sales of $6.6 million, reflecting a higher average coal sales price per ton of $52.32 in the 2006 Quarter, an increase of $5.25 per ton over the 2005 Quarter average coal sales price per ton, (which contributed $4.8 million of the increase in coal sales) and increased tons sold of 40,000 tons in the 2006 Quarter, (contributing $1.8 million of the increase in coal sales). Segment Adjusted EBITDA Expense for the 2006 Quarter increased 28.0% to $35.6 million from $27.8 million in the 2005 Quarter. The increase in the 2006 Quarter Segment Adjusted EBITDA Expense compared to the 2005 Quarter primarily reflects the impact of cost increases described above under consolidated operating expenses and the high cost of Van Lear production.

Northern Appalachia Segment Adjusted EBITDA for the 2006 Quarter decreased $2.2 million, or 24.4%, to $6.9 million as compared to the 2005 Quarter Segment Adjusted EBITDA of $9.1 million. The decrease was primarily attributable to a $2.9 million reduction of coal sales reflecting a lower average sales price per ton of $1.44 to $29.51 per ton in the 2006 Quarter (which contributed $1.0 million of the decrease in coal sales) and decreased tons sold of 60,000 tons (which contributed $1.9 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 decrease in the 2006 Quarter Segment Adjusted EBITDA Expense compared to the 2005 Quarter primarily reflects lower tons sold partially offset by the impact of cost increases described above under consolidated operating expenses.

Other and Corporate The increase in coal sales and Segment Adjusted EBITDA Expense primarily reflects the coal sales and operating expenses attributable to the brokerage coal purchases and coal sales associated with the ICG agreement described above.

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

	Three Months Ended June 30,	
	2006	2005
Segment Adjusted EBITDA	$ 66,963	$ 68,934
General & administrative	(7,091)	(10,547)
Depreciation, depletion and amortization	(16,288)	(13,396)
Interest expense, net	(2,530)	(3,370)
Income taxes	(547)	(829)
Minority interest	43	
Net income	$ 40,550	$ 40,792

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

We reported record net income for the six months ended June 30, 2006 (the 2006 Period) of $88.8 million, an increase of 11.2% over the six months ended June 30, 2005 (the 2005 Period). Increased results for the 2006 Period were primarily attributable to record sales volumes and average coal sales prices reflecting the continuation of favorable coal markets, which benefit was partially offset by increased operating expenses.

	June 30,		June 30,	
	2006	2005	2006	2005
	(in thousands)		(per ton sold)	
Tons sold	11,672	11,388	N/A	N/A
Tons produced	12,050	11,371	N/A	N/A
Coal sales	$ 423,725	$ 370,973	$ 36.30	$ 32.58
Operating expenses and outside purchases	$ 301,118	$ 255,027	$ 25.80	$ 22.39

Coal sales. Coal sales increased 14.2% to $423.7 million for the 2006 Period from $371.0 million for the 2005 Period. The increase of $52.7 million reflects increased sales volumes (contributing $9.3 million of the increase) and higher coal sales prices (contributing $43.4 million of the increase). Tons sold increased 2.5% to 11.7 million tons for the 2006 Period from 11.4 million tons for the 2005 Period. Tons produced increased 6.0% to 12.1 million tons for the 2006 Period from 11.4 million tons for the 2005 Period.

Operating expenses. Operating expenses increased 18.3% to $292.9 million for the 2006 Period from $247.5 million for the 2005 Period. The increase of $45.4 million resulted from an increase in operating expenses associated with additional coal sales of 284,000 tons, including the following specific factors:

Labor and benefit costs increased $16.5 million reflecting increased headcount, pay rate increases and escalating health care costs;

Material and supplies, and maintenance costs increased $18.4 million and $2.6 million, respectively, reflecting increased production and increased costs for certain products and services used in the mining process;

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Third-party mining costs increased $4.0 million reflecting increased production at two small third-party mining operations at Mettiki;

Production taxes and royalties (which are incurred as a percentage of coal sales or volumes) increased $4.2 million;

Property insurance costs increased $2.5 million;

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

Costs of $6.2 million in the 2006 Period were associated with the purchase of tons under the settlement agreement we entered into with ICG in November 2005. Consistent with the guidance in EITF No. 04-13, 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 reported as an operating expense; and

Operating expenses were reduced by $7.2 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.

General and administrative. General and administrative expenses decreased to $14.2 million for the 2006 Period from $16.3 million for the 2005 Period. The decrease of $2.1 million was primarily related to lower unit-based incentive compensation expense associated with the LTIP and STIP. Prior to our adoption of 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.

Other sales and operating revenues. Other sales and operating revenues increased 10.1% to $16.9 million for the 2006 Period from $15.4 million for the 2005 Period. The increase of $1.5 million was primarily attributable to $1.5 million of additional rental and service fees associated with a new third-party coal synfuel facility at Gibson County Coal, which began producing synfuel in May 2005, partially offset by a decrease of $0.6 million for rent and service fees associated with decreased volumes at a third-party coal synfuel facility at Warrior. The 2006 Period also benefited from administrative service revenue of $0.5 million in the 2006 Period. Please read Item 2. Summary above for a discussion regarding the suspension of third-party coal synfuel facilities.

Outside purchases. The increase in outside purchases to $8.2 million for the 2006 Period from $7.5 million in the 2005 Period was primarily attributable to an increase in outside purchases at our Central and Northern Appalachia operations to supply new market opportunities partially offset by lower outside purchases in Illinois Basin.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $31.0 million for the 2006 Period from $27.0 million for the 2005 Period. The increase of $4.0 million is primarily attributable to additional depreciation expense associated with an increase of capital expenditures, particularly at our Elk Creek, Mountain View and Van Lear projects and infrastructure investments in recent years which have increased our production capacity.

Interest expense. Interest expense decreased to $6.6 million for the 2006 Period from $7.9 million for the 2005 Period. The decrease of $1.3 million was principally attributable to the capitalization of interest expense related to capital projects and/or mine development costs at our Elk Creek, Mountain View, Pontiki and Gibson mines in addition to reduced interest expense associated with the August 2005 scheduled principal payment of $18.0 million on our senior notes. We had no borrowings under the credit facility during the 2006 or 2005 Periods.

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Interest Income. Interest income increased to $1.8 million for the 2006 Period from $1.1 for the 2005 Period. The increase of $0.7 million resulted from increased interest income earned on marketable securities.

Transportation revenues and expenses. Transportation revenues and expenses increased to $19.0 million in the 2006 Period compared to $18.0 million in the 2005 Period. The increase of $1.0 million was primarily attributable to higher sales volumes for which we arrange transportation. The cost of transportation services are passed through to our customers. Consequently, we do not realize any margin on transportation revenues.

Income before income taxes, cumulative effect of accounting change and minority interest. Income before income taxes, cumulative effect of accounting change and minority interest increased to $90.0 million for the 2006 Period from $81.4 million for the 2005 Period. The increase of $8.6 million was primarily attributable to increased sales volumes and higher coal prices partially offset by higher operating expenses.

Income tax expense. Income tax expense was comparable for the 2006 and 2005 Periods at $1.3 million and $1.5 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.

Minority interest. In March 2006 our subsidiary, White County Coal and House entered into a Limited Liability Company Agreement to form MAC. MAC was formed to engage in the development and operation of a rock dust mill. The main purpose of the rock dust mill will be to manufacture and sell rock dust. We consolidate MAC s financial results in accordance with FIN 46R. Based on the guidance in FIN 46R, we concluded that MAC is a variable interest entity and that we are the primary beneficiary. House s portion of MAC s net loss was $43,000 for the 2006 Period and is recorded as minority interest on our condensed consolidated income statement.

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Our 2006 Period Segment Adjusted EBITDA increased $8.5 million, or 6.4%, to $140.0 million from the 2005 Period Segment Adjusted EBITDA of $131.5 million. Segment Adjusted EBITDA, tons sold, coal sales, operating revenues and Segment Adjusted EBITDA Expense by segment are as follows (in thousands):

	Six Months Ended June 30,			
	2006	2005	Increase/(Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 98,695	$ 92,492	$ 6,203	6.7%
Central Appalachia	23,647	16,720	6,927	41.4%
Northern Appalachia	14,750	21,520	(6,770)	(31.5)%
Other and Corporate	2,892	801	2,091	261.0%
Total Segment Adjusted EBITDA (1)	$ 139,984	$ 131,533	$ 8,451	6.4%
Tons sold				
Illinois Basin	8,233	8,290	(57)	(0.7)%
Central Appalachia	1,881	1,409	472	33.5%
Northern Appalachia	1,558	1,689	(131)	(7.8)%
Other and Corporate				
Total tons sold	11,672	11,388	284	2.5%
Coal sales				
Illinois Basin	$ 274,753	$ 251,451	$ 23,302	9.3%
Central Appalachia	94,567	64,414	30,153	46.8%
Northern Appalachia	46,577	55,108	(8,531)	(15.5)%
Other and Corporate	7,828		7,828	100.0%
Total coal sales	$ 423,725	$ 370,973	$ 52,752	14.2%
Other sales and operating revenues				
Illinois Basin	$ 13,386	$ 12,242	$ 1,144	9.3%
Central Appalachia	238	186	52	28.0%
Northern Appalachia	1,052	1,165	(113)	(9.7)%
Other and Corporate	2,233	1,770	463	26.2%
Total other sales and operating revenues	$ 16,909	$ 15,363	$ 1,546	10.1%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 189,444	$ 171,202	$ 18,242	10.7%
Central Appalachia	71,159	47,880	23,279	48.6%
Northern Appalachia	32,879	34,752	(1,873)	(5.4)%
Other and Corporate	7,168	969	6,199	639.7%
Total Segment Adjusted EBITDA Expense (2)	$ 300,650	$ 254,803	$ 45,847	18.0%

(1) Segment Adjusted EBITDA is defined as net income before income taxes, cumulative effect of accounting change and minority interest, interest expense and interest income, depreciation, depletion and amortization, and general and administrative expense. Segment Adjusted 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 the 2006 Period increased 6.7%, to $98.7 million from the 2005 Period Segment Adjusted EBITDA of $92.5 million. The increase of $6.2 million was primarily attributable to increased coal sales which rose by $23.3 million, or 9.3%, to $274.8 million

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during the 2006 Period as compared to $251.5 million in the 2005 Period. Increased coal sales in the 2006 Period reflects a higher average coal sales price per ton which increased $3.04 per ton to $33.37 per ton (contributing $25.0 million of the increase in coal sales) partially offset by decreased tons sold of 57,000 tons (reducing the coal sales variance by $1.7 million). Other sales and operating revenues increased $1.1 million, primarily due to $1.5 million of revenues associated with the coal synfuel facility that began operating at Gibson in the 2005 Period partially offset by a decrease of $0.6 million for rent and service fees associated with decreased synfuel volumes at Warrior. Total Segment Adjusted EBITDA Expense for the 2006 Period increased 10.7% to $189.4 million from $171.2 million in the 2005 Period. On a per ton sold basis, the 2006 Period Segment Adjusted EBITDA Expense rose to $23.01 per ton, an increase of 11.4% over the 2005 Period Segment Adjusted EBITDA Expense per ton of $20.65 per ton. The increase in the 2006 Period Segment Adjusted EBITDA Expense compared to the 2005 Period primarily reflects the impact of cost increases described above under consolidated operating expenses. Illinois Basin costs have been negatively impacted by high cost production at the Elk Creek mine which has emerged from development during the 2006 Period, but has not yet reached full production capacity.

Central Appalachia Segment Adjusted EBITDA for the 2006 Period increased $6.9 million, or 41.4%, to $23.6 million as compared to the 2005 Period Segment Adjusted EBITDA of $16.7 million. The increase was primarily attributable to increased coal sales of $30.2 million, reflecting a higher average coal sales price per ton of $50.28 in the 2006 Period, an increase of $4.58 per ton over the 2005 Period average coal sales price per ton, (which contributed $8.7 million of the increase in coal sales) and increased tons sold of 472,000 tons in the 2006 Period (which contributed $21.5 million of the increase in coal sales) partially offset by an increase in Segment Adjusted EBITDA Expense for the 2006 Period of 48.6% to $71.2 million from $47.9 million in the 2005 Period. The increase in the 2006 Period Segment Adjusted EBITDA Expense compared to the 2005 Period primarily reflects the increase in tons sold. On a per ton basis, the 2006 Period Segment Adjusted EBITDA Expense rose $3.87 per ton reflecting the impact of cost increases described above under consolidated operating expenses. Additionally, Central Appalachia costs have been negatively impacted by high cost production from Pontiki s Van Lear mine which has emerged from development during the fourth quarter of 2005, but has not yet reached full production capacity. The production increase was primarily attributable to the negative impact of the MC Mining Fire Incident on production in the 2005 Period.

Northern Appalachia Segment Adjusted EBITDA for the 2006 Period decreased $6.8 million, or 31.5%, to $14.8 million as compared to the 2005 Period Segment Adjusted EBITDA of $21.6 million. The decrease was primarily attributable to a $8.5 million reduction of coal sales reflecting a lower average sales price per ton of $2.75 to $29.88 per ton in the 2006 Period (which contributed $4.3 million of the decrease in coal sales) and decreased tons sold of 131,000 tons (which contributed $4.2 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 Period. The increase in the 2006 Period Segment Adjusted EBITDA Expense compared to the 2005 Period primarily reflects the impact of cost increases described above under consolidated operating expenses, partially offset by lower tons sold.

Other and Corporate The increase in coal sales and Segment Adjusted EBITDA Expense primarily reflects the coal sales and operating expenses attributable to the brokerage coal purchases and coal sales associated with the ICG agreement described above.

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

	Six Months Ended June 30,	
	2006	2005
Segment Adjusted EBITDA	$ 139,984	$ 131,533
General & administrative	(14,249)	(16,255)
Depreciation, depletion and amortization	(31,010)	(27,024)
Interest expense, net	(4,775)	(6,844)
Income taxes	(1,306)	(1,539)
Minority interest	43	
Cumulative effect of accounting change	112	
Net income	$ 88,799	$ 79,871

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.

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Following the initial two submittals by us to 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 $4.0 million and $12.2 million were received, during the six months ended June 30, 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 $10.3 million, during the six months ended June 30, 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.

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Cash provided by operating activities was $128.8 million for the 2006 Period compared to $96.4 million for the 2005 Period. 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 Period compared to the 2005 Period and an increase in net income. Total working capital changes include a reduced use of cash attributable to accounts receivable and other receivables partially offset by an increased use of cash for inventory in the 2006 Period compared to the 2005 Period. The 2005 Period included an increase in accounts receivable related to the MC Mining Fire Incident described above and higher trade accounts receivable attributable to slower payments from certain customers.

Net cash used in investing activities was $70.1 million for the 2006 Period compared to $42.8 million for the 2005 Period. The increase is primarily attributable to an increase in capital expenditures associated with the Elk Creek and Mountain View mines and the acquisition of coal reserves for the River View mine and additional reserves acquired in Eastern Kentucky. We are currently estimating total capital expenditures in 2006 to range from approximately $175.0 million to $190.0 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 increased proceeds from marketable securities net of marketable securities purchases, during the 2006 Period.

Net cash used in financing activities primarily was $42.2 million for the 2006 Period compared to $29.6 million for the 2005 Period. The increase is attributable to increased distributions to partners in the 2006 Period.

Capital Expenditures

Capital expenditures increased to $92.0 million in the 2006 Period from $47.3 million in the 2005 Period. 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 Flows.

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. Borrowings under the Credit Facility bear interest based on a floating base rate plus an applicable margin. The applicable margin is based on a leverage ratio of our intermediate partnership, as computed from time to time. The initial applicable margin for borrowings under the Credit Facility is 0.875% with respect to London Interbank Offered Rate (LIBOR) borrowings. 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 June 30, 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 June 30, 2006.

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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, affecting our intermediate partnership and its subsidiaries restricting, among other things, the amount of distributions by our intermediate partnership, the incurrence of additional indebtedness and liens, the sale of assets, the making of investments, the entry into mergers and consolidations and the entry into transactions with affiliates, in each case subject to various exceptions. The Senior Notes and the Credit Facility also require the intermediate partnership to remain in control of a certain amount of mineable coal based on a ratio of the amount of total mineable tons controlled by the intermediate partnership relative to its annual production. In addition, the Senior Notes and the Credit Facility require the intermediate partnership to comply with certain financial ratios, including a maximum leverage ratio and a minimum interest coverage ratio. We were in compliance with the covenants of both the Credit Facility and Senior Notes at June 30, 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 $31.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers compensation benefits. At June 30, 2006, we had $26.2 million in letters of credit outstanding under these agreements. Our special general partner guarantees $5.0 million of 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 closing of the IPO of AHGP (see Item 2. Summary above), we entered 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 of our own personnel, including executive officers, are providing administrative services to our managing general partner, AHGP, Alliance GP, LLC (Alliance GP), the general partner of AHGP, ARH II, and their respective affiliates. We will be reimbursed for services rendered by our employees on behalf of these affiliates as provided under the Administrative Services Agreement. Concurrently, AHGP, Alliance GP and our managing general partner joined as parties to our Omnibus Agreement, which addresses areas of non-competition between AHGP and us.

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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 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, we 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.

In June 2006, the FASB issued FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. The interpretation prescribes a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The provisions of FIN 48 are effective for fiscal years beginning after December 31, 2006. We are currently in the process of assessing the provisions of FIN 48, but do not expect the adoption of FIN 48 to have a material impact on our consolidated financial statements.

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.

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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 June 30, 2006.

As of June 30, 2006, the estimated fair value of the Senior Notes was approximately $171.3 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. 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 believe the design and operation of these controls and procedures are effective to ensure that the Partnership is able to collect, process and disclose the information it is required to disclose in the reports it files with the SEC within the required time periods, and during the quarterly period ended June 30, 2006, there have not been any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) identified in connection with this evaluation 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 we do not believe that an adverse decision in this litigation matter, if any, will have a material adverse effect on our business, financial position or results of operations.

In March 2004, XL Specialty Insurance Company (XL) filed litigation against ARH and us in state court of Oklahoma alleging that we and ARH had failed to indemnify XL for Alliance Coal s failure to pay certain annual premiums associated with four surety bonds issued to the State of Kentucky to secure Alliance Coal s self-insurance workers compensation status. All four of these surety bonds were cancelled by XL in 2001 after it made the business decision to withdraw from the surety market. In the lawsuit, XL requested that the trial court determine, under two indemnity agreements, we and ARH were found to be jointly and severely liable to XL for bond premiums on the four cancelled surety bonds in the total principal amount of approximately $397,000, plus pre- and post-judgment interest. In answering the lawsuit, we and ARH filed a counterclaim against XL raising a number of affirmative defenses and counterclaiming for breach of contract and bad faith. In July 2006, a bench trial occurred in which XL alleged that Alliance Coal owed approximately $876,000 (including interest) through September 2005. In support of its counterclaim, we and ARH alleged damages of approximately $400,000 relating to certain increased costs associated with Alliance Coal s surety bond program. The matter is currently pending before the trial court for a decision. We believe this complaint is without merit and we do not believe that an adverse decision in this litigation matter, if any, will have a material adverse effect on our business, financial position or results of operations.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in the Quarterly Report on Form 10-Q, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2005, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial based on current knowledge and factual circumstances and, if such knowledge or factors change, also may materially adversely affect our business, financial condition and/or operating results in the future.

Other risk factors to consider are as follows:

On July 31, 2006, we received a letter from the managing member of Synfuel Solutions Operating, LLC (SSO), that 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

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synfuel production facility located at our Warrior Coal, LLC (Warrior) mining complex in Hopkins County, Kentucky. Previously, SSO had suspended operation of the synfuel facility effective April 23, 2006 due to the increase in the wellhead price of domestic crude oil. The suspension period lasted until May 11, 2006 when SSO resumed operation of its coal synfuel production facility. 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.

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 closed on May 15, 2006, represented 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 for federal income tax purposes 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 will not affect our classification as a partnership for federal income tax purposes, but instead, we will be treated as a new partnership for tax purposes. As a new partnership, we must make new tax elections and could be subject to penalties if we are unable to substantiate that a termination occurred.

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

10.1	Second Amendment to the Omnibus Agreement dated May 15, 2006 by and among Alliance Resource Partners, L.P., Alliance Resource GP, LLC, Alliance Resource Management GP, LLC, Alliance Resource Holdings, Inc., Alliance Resource Holdings II, Inc., AMH-II, LLC, Alliance Holdings GP, L.P., Alliance GP, LLC and Alliance Management Holdings, LLC.
10.2	Administrative Services Agreement dated May 15, 2006 among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Holdings GP, L.P. and Alliance GP, LLC.
10.3	Amendment No. 2 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Fifth Third Bank (Incorporated by reference to Exhibit 10.1 of the Registrant s Form 8-K filed with the Commission on May 16, 2006, File No. 000-26823).
10.4	The termination of Guarantee Agreement, dated as of April 24, 2006, between Alliance Resource GP, LLC and Fifth Third Bank (Incorporated by reference to Exhibit 10.2 of the Registrant s Form 8-K filed with the Commission on May 16, 2006, File No. 000-26823).
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 August 9, 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 August 9, 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 August 9, 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 August 9, 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 August 9, 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