UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2005

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

For the transition period from to .

Commission File Number: 1-13105

ARCH COAL, INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**43-0921172** (I.R.S. Employer Identification Number)
One CityPlace Drive, Suite 300, St. Louis, Missouri (Address of principal executive offices)	**63141** (Zip code)

Registrant's telephone number, including area code: (314) 994-2700

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $.01 par value	**New York Stock Exchange**
Preferred Share Purchase Rights	**New York Stock Exchange**
5% Perpetual Cumulative Convertible Preferred Stock	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ☑

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No o

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

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 ☑ Accelerated Filer o Non-Accelerated Filer o

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

At June 30, 2005, based on the closing price of the registrant's common stock on the New York Stock Exchange on that date, the aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $1.7 billion. In determining this amount, the registrant has assumed that all of its executive officers and directors, and persons known to it to be the beneficial owners of more than five percent of its common stock, are affiliates. Such assumption shall not be deemed conclusive for any other purpose.

At March 1, 2006, there were 71,383,765 shares of the registrant's common stock outstanding.

Documents incorporated by reference:

1. Portions of the registrant's definitive proxy statement, to be filed with the Securities and Exchange Commission no later than April 1, 2006, are incorporated by reference into Part III of this Form 10-K

2. Portions of the registrant's Annual Report to Stockholders for the year ended December 31, 2005 are incorporated by reference into Parts I, II and IV of this Form 10-K.

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PART I

ITEM 1. BUSINESS.

This document contains "forward-looking statements" — that is, statements related to future, not past, events. In this context, forward-looking statements often address our expected future business and financial performance, and often contain words such as "expects," "anticipates," "intends," "plans," "believes," "seeks," or "will." Forward-looking statements by their nature address matters that are, to different degrees, uncertain. For us, particular uncertainties arise from changes in the demand for our coal by the domestic electric generation industry; from legislation and regulations relating to the Clean Air Act and other environmental initiatives; from operational, geological, permit, labor and weather-related factors; from fluctuations in the amount of cash we generate from operations; from future integration of acquired businesses; and from numerous other matters of national, regional and global scale, including those of a political, economic, business, competitive or regulatory nature. These uncertainties may cause our actual future results to be materially different than those expressed in our forward-looking statements. We do not undertake to update our forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by law. For a description of some of the risks and uncertainties that may affect our future results, see "Risk Factors" under Item 1A.

General

Arch Coal, Inc. is one of the largest coal producers in the United States. From mines located in both the eastern and western United States, we mine, process and market bituminous and sub-bituminous coal with a low sulfur content. Because of the location of our mines, we are able to ship coal cost-effectively to most of the major domestic coal-fired electric generation facilities. We sell substantially all of our coal to producers of electric power, steel producers and industrial facilities. In 2005, we sold approximately 140.2 million tons of coal, including approximately 11.2 million tons of coal we purchased from third parties.

At December 31, 2005, we operated 21 active mines and controlled approximately 3.1 billion tons of proven and probable coal reserves. Federal and state legislation controlling air pollution affects the demand for certain types of coal by limiting the amount of sulfur dioxide which may be emitted as a result of fuel combustion and encourages a greater demand for low sulfur coal. At December 31, 2005, we estimate our proven and probable coal reserves had an average heat value of approximately 9,900 Btus and an average sulfur content of approximately 0.62%.

Our History

We were organized in Delaware in 1969 as Arch Mineral Corporation. In July 1997, we merged with Ashland Coal, Inc. As a result of the merger, we became a leading producer of low-sulfur coal in the eastern United States.

In June 1998, we expanded into the western United States when we acquired the coal assets of Atlantic Richfield Company. This acquisition included the Black Thunder and Coal Creek mines in the Powder River Basin of Wyoming, the West Elk longwall mine in Gunnison County, Colorado and a 65% interest in Canyon Fuel Company, which operates three longwall mines in Utah.

In October 1998, we added to our Powder River Basin reserves when we were the winning bidder of the Thundercloud reserve, a 412-million-ton federal reserve tract adjacent to the Black Thunder mine. In July 2004, we acquired the remaining 35% interest in Canyon Fuel Company. In August 2004, we again expanded our position in the Powder River Basin with the acquisition of Triton Coal Company's North Rochelle mine adjacent to our Black Thunder operation. In September 2004, we again added to our Powder River Basin reserves when we were the winning bidder for the Little Thunder reserve, a 719-million ton federal reserve tract adjacent to the Black Thunder mine.

Recent Developments

On December 30, 2005, we completed a reserve swap with Peabody Energy and sold to Peabody a rail spur, rail loadout and idle office complex located in the Powder River Basin for a purchase price of $84.6 million. In the reserve swap, we exchanged 60 million tons of coal reserves near the former North Rochelle mine for a similar block of 60 million tons of coal reserves more strategically positioned relative to our Black Thunder mining complex. We believe the reserve exchange will provide us with a more efficient mine plan.

On December 31, 2005, we accepted for conversion 2,724,418 shares of our preferred stock, representing approximately 95% of the preferred stock issued and outstanding on that date, pursuant to the terms of a conversion offer. As a result of the conversion offer, we issued an aggregate of 6,534,517 shares of common stock pursuant to the conversion terms of the preferred stock and an aggregate premium of 119,602 shares of common stock. As of March 1, 2006, 150,508 shares of preferred stock remain outstanding.

On December 31, 2005, we sold 100% of the stock of Hobet Mining, Apogee Coal Company and Catenary Coal Company, which include the Hobet 21, Arch of West Virginia, Samples and Campbells Creek mining operations and approximately 455 million tons of coal reserves located in Central Appalachia, to Magnum Coal Company in exchange for approximately $15.0 million, subject to certain adjustments, and the assumption by Magnum Coal Company of certain liabilities. The mining operations we sold to Magnum Coal Company produced approximately 12.5 million tons of coal in 2005. Our operating results for 2005, 2004 and 2003 contained in this report include results from the mining operations we sold to Magnum. Our reserves and other financial statement information as of December 31, 2005 contained in this report do not include the reserves and other assets or liabilities associated with the mining operations we sold to Magnum.

On February 10, 2006, we established a $100 million accounts receivable securitization program. Under the program, undivided interests in a pool of eligible trade receivables are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit. Purchases by the conduit are financed with the sale of highly-rated commercial paper. We may use the proceeds from the sale of accounts receivable in the program as an alternative to other forms of debt.

On February 23, 2005, our board of directors elected Steven F. Leer, our president and chief executive officer, as chairman of the board of directors, effective April 28, 2006. Mr. Leer will continue to act as president and chief executive officer until April 28, 2006, at which time Mr. Leer will assume the responsibilities of chairman of the board and chief executive officer. In addition, the board of directors elected John W. Eaves, our executive vice president and chief operating officer, as president, effective April 28, 2006.

The board of directors also increased the size of the board of directors to eleven and elected Mr. Eaves to fill the newly-created vacancy, effective immediately.

The Coal Industry

Overview. Coal is a major contributor to the global energy supply, representing more than 24% of international primary energy consumption, according to the World Coal Institute. The United States produces more than one-fifth of the world's coal and is the second largest coal producer in the world, exceeded only by China. Coal in the United States represents approximately 95% of the domestic fossil energy reserves with over 250 billion tons of recoverable coal, according to the United States Geological Survey.

Coal is primarily used to fuel electric power generation in the United States. Based on preliminary data from the Energy Information Administration, which we refer to as the EIA, coal-based power plants generated approximately 50% of the electricity produced in the United States in 2005. Coal also represents the lowest cost fossil fuel used for electric power generation making it critical to the United States economy. According to the EIA, the average delivered cost of coal to electric power generators for the first nine months of 2005 was $1.52/mm Btu, which was $5.05/mm Btu less expensive than residual fuel oil and $5.98/mm Btu less expensive than natural gas.

Several events occurring in 2005 highlighted coal's relative importance to the United States. Compared to other fuels used for electric power generation, coal is domestically-available, reliable, and can be used in an environmentally-friendly manner. Prices for oil and natural gas in the United States reached record levels in 2005 because of tensions regarding international supply and disruptions from two major hurricanes. High prices have resulted in renewed interest, not only in adding new coal-based electric power generation, but also in "refining coal" into transportation fuels, such as low-sulfur diesel. According to data from Platts, over 80,000 megawatts of new coal-based generation is now planned in the United States. Additionally, government and private sector interest in coal-gasification and coal-to-liquids technologies has increased.

Record level demand for coal in the United States strained production and transportation in 2005. We expect coal to continue to grow as a domestic fuel as capital is deployed for mine development and expansion and for increased railroad capacity. During 2005, a third rail-carrier announced that it is seeking financing to construct rail access to the Powder River Basin in Wyoming. We believe this announcement further demonstrates the commitment to coal as a future source of fuel for the United States.

The coal industry also experienced record low miner fatalities in 2005. We expect that the industry will continue to explore ways to further reduce and eliminate work-place hazards in the coming years.

Coal is expected to remain the fuel of choice for domestic power generation through 2030, according to the EIA. Through that time, we expect new technologies intended to lower emissions of sulfur dioxide, nitrous oxides, mercury, and particulates will be introduced into the power generation industry. We believe these advancements will help coal retain its role as a key fuel for electric power generation well into the future.

U.S. Coal Consumption. Coal produced in the United States is used primarily by utilities to generate electricity, by steel companies to produce coke for use in blast furnaces and by a variety of industrial users to heat and power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Production of coal in the United States has increased from 434 million tons in 1960 to about 1.1 billion tons in 2004 based on information provided by EIA.

According to the EIA, U.S. coal consumption by sector for 2003 and 2004, the last years for which final information is currently available, is as follows:

	2003		2004	
End Use	**Tons (millions)**	**% of Total**	**Tons (millions)**	**% of Total**
Electric generation	1,005.1	91.8%	1,016.3	91.9%
Industrial	61.3	5.6%	61.2	5.5%
Steel production	24.3	2.2%	23.7	2.1%
Residential/ Commercial	4.2	0.4%	4.2	0.4%
Total	1,094.9	100.0%	1,105.4	100.0%

Source: EIA

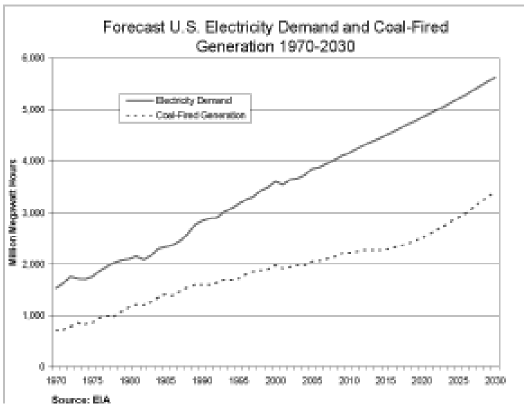
Coal has long been favored as an electricity generating fuel by utilities because of its cost advantage and its availability throughout the United States. According to the EIA, coal accounted for 50% of U.S. electricity generation in 2004 and is projected to account for 57% in 2030 since generation from natural gas is expected to peak in 2020. The largest cost component in electricity generation is fuel. According to the National Mining Association, which we refer to as the NMA, coal is the lowest cost fossil fuel used for electric power generation, averaging less than one-third of the price of both petroleum and natural gas. According to the EIA, for a new coal-fired plant built today, fuel costs would represent about one-half of total operating costs, whereas the share for a new natural gas-fired plant would be almost 90%. Other factors that influence each utility’s choice of electricity generation method include facility cost, fuel transportation infrastructure, environmental restrictions and other factors. According to the EIA, the breakdown of U.S. electricity generation by fuel source in 2004, the last year for which final information is currently available, is as follows:

Electricity Generation Mode	**% of Total U.S. Electricity Generation**
Coal	50.0%
Nuclear	19.9%
Natural gas	17.7%
Hydro	6.8%
Petroleum	3.0%
Other	2.6%
Total	100.0%

Source: EIA

The EIA projects that generators of electricity will increase their demand for coal as demand for electricity increases. Because coal-fired generation is used in most cases to meet base load requirements, coal consumption has generally grown at the pace of electricity growth. Demand for electricity has historically grown in proportion to the U.S. economic growth by gross domestic product. Coal consumption patterns are also influenced by governmental regulation impacting coal production and power generation, technological developments and the location, availability and quality of competing sources of coal, as well as other fuels such as natural gas, oil and nuclear and alternative energy sources such as hydroelectric power. According to the EIA, coal use for electricity generation is expected to increase on average by 1.8% per year from 2004 to 2025.

The following chart sets forth the forecasted domestic electricity demand and the portion of demand that is forecasted to be generated by coal based on information provided by the EIA:



The other major market for coal is the steel industry. Metallurgical coal is distinguished by special quality characteristics including high carbon content, low expansion pressure, low sulfur content and various other chemical attributes. Metallurgical coal is also high in heat value and therefore in some instances desirable to utilities as fuel for electricity generation. The price offered by steel makers for the metallurgical quality attributes is typically higher than the price offered by utility coal buyers for steam coal.

U.S. Coal Production. In 2004, the last year for which information is currently available, total coal production in the United States as estimated by the U.S. Department of Energy was 1.1 billion tons. According to the EIA, the breakdown of U.S. coal production by production region for 2003 and 2004, the last years for which final information is currently available, is as follows (tons in millions):

	2003		2004	
	Tons	**%**	**Tons**	**%**
Appalachia	376.1	35.1%	389.9	35.1%
Western	548.7	51.2%	575.2	51.8%
Interior(1)	146.0	13.6%	146.0	13.1%
Total	1,070.8	100.0%	1,111.1	100.0%

Source: EIA

(1) Includes the Illinois Basin

Appalachian Region. Central Appalachia, including eastern Kentucky, Virginia and southern West Virginia, produced 20.8% of the total U.S. coal production in 2004. Coal mined from this region generally has a high heat value of between 12,000 and 14,000 Btus per pound and low sulfur content ranging from 0.7% to 1.5%. From 2002 to 2004, according to the Mine Safety and Health Administration, Central Appalachia experienced a 6.7% decline in production from 248.7 million tons to 232.0 million tons, primarily as a result of the depletion of economically attractive reserves, permitting issues and increasing costs of production. These factors were partially offset by production increases in southern West Virginia due to the expansion of more economically attractive surface mines. Northern Appalachia includes Maryland, Ohio, Pennsylvania and northern West Virginia. Coal from this region generally has a high heat value of between 12,000 and 14,000 Btus per pound. Its typical sulfur content ranges from 1.0% to 4.5%. Southern Appalachia includes Alabama and Tennessee. Coal mined from this region generally has a high heat value of between 12,500 and 14,000 Btus per pound and low sulfur content ranging from 0.7% to 1.5%.

Western United States. The Powder River Basin is located in northeastern Wyoming and southeastern Montana. Coal from this region has a very low sulfur content of between 0.15% to 0.55% and a low heat value of between 7,500 and 10,000 Btus per pound. Coal shipped east from the Powder River Basin competes with coal sold in the Appalachian region. The price of Powder River Basin coal is less than that of coal produced in Central Appalachia because Powder River Basin coal exists in greater abundance, is easier to mine and thus has a lower cost of production. However, Powder River Basin coal is generally lower in heat value, which requires some electric utilities to either blend it with higher Btu coal or retrofit existing coal plants to accommodate lower Btu coal. The Western Bituminous region includes western Colorado and eastern Utah. Coal from this region typically has a sulfur content of between 0.5% and 1.0% and a heat value of between 10,500 and 12,500 Btus per pound. The Four Corners area includes northwestern New Mexico, northeastern Arizona, southwestern Utah and southeastern Colorado. The coal from this region typically has a sulfur content of between 0.75% and 1.0% and a heat value of between 9,000 and 10,000 Btus per pound.

Interior region. The Illinois Basin includes Illinois, Indiana and western Kentucky and is the major coal production center in the interior region of the United States. There has been significant consolidation among coal producers in the Illinois Basin over the past several years. Coal from this region varies in heat value from 10,000 to 12,500 Btus per pound and has a high sulfur content of between 2.0% and 4.0%.

Other coal-producing states in the interior region of the United States include Arkansas, Kansas, Louisiana, Mississippi, Missouri, North Dakota, Oklahoma and Texas. The majority of production in the interior region outside of the Illinois Basin consists of lignite coal production from Texas and North Dakota. This lignite coal typically has a heat value of between 5,000 and 9,500 Btus per pound and a sulfur content of between 1.0% and 2.0%.

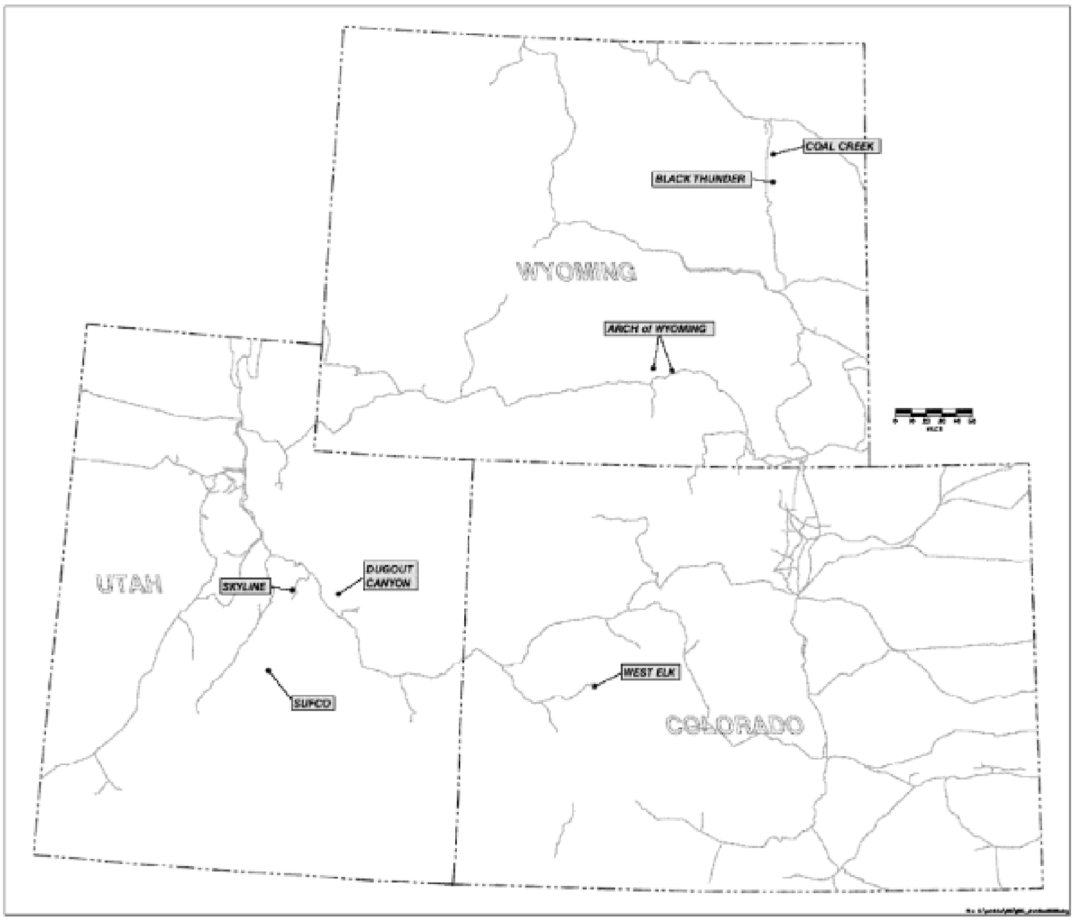
International Coal Production. Coal is imported into the United States, primarily Columbia and Venezuela. Imported coal generally serves coastal states along the Gulf of Mexico, such as Alabama and Florida, and states along the eastern seaboard. We believe that significant new capital expenditures for transportation infrastructure would have to be incurred by inland coal consumers in the United States if they desired to import significant quantities of foreign coal because most U.S. waterways and water transportation facilities are built for export rather than import of coal. However, coal imports have demonstrated recent strength due to their competitive pricing, particularly when compared to Appalachian coal.

Our Mining Operations

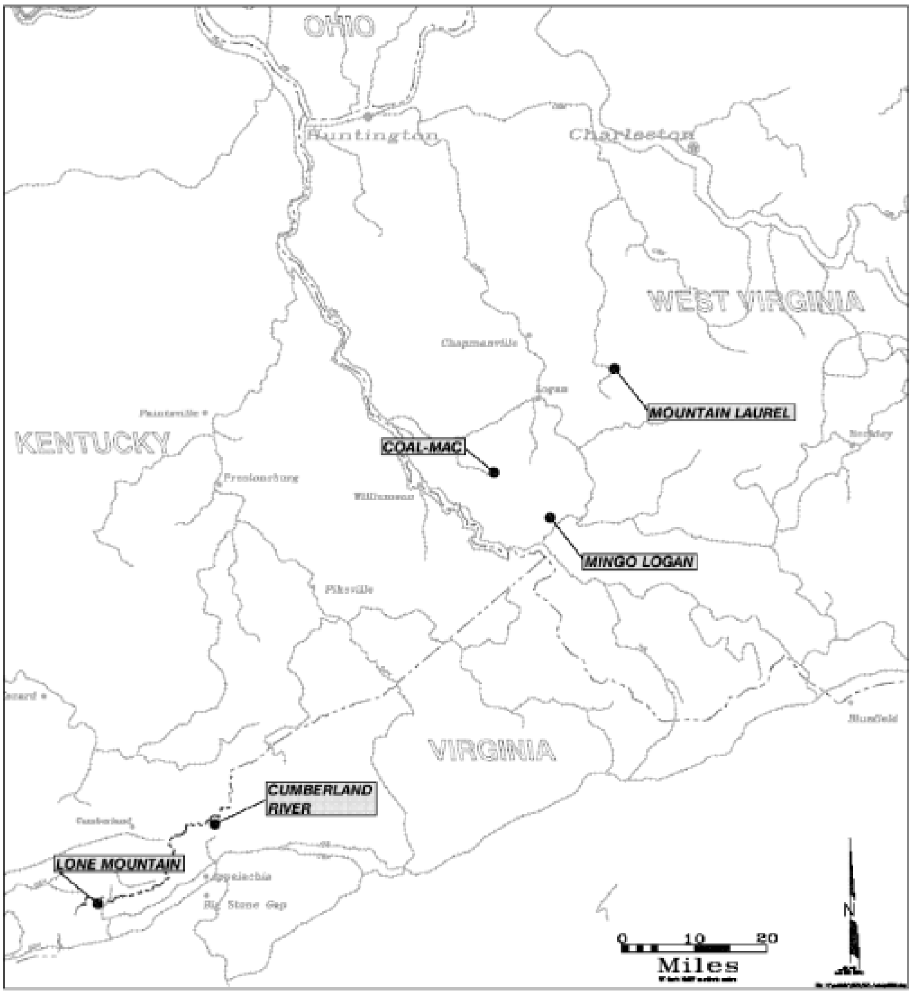
As of December 31, 2005, we operated 21 active mines, all located in the United States. We have three reportable business segments, which are based on the low sulfur coal producing regions in the United States in which we operate — the Central Appalachia region, the Powder River Basin and the Western Bituminous region. These geographically distinct areas are characterized by geology, coal transportation routes to consumers, regulatory environments and coal quality. These regional similarities have caused market and contract pricing environments to develop by coal region and form the basis for the segmentation of our operations.

The following maps show the locations of our significant mining operations:

Powder River Basin and Western Bituminous



Central Appalachia



We expect our mine management teams to focus their efforts on controlling costs, managing volume and managing the revenue adjustments that may be necessary as a result of the quality of coal produced for contract shipments assigned to a specific mine. We evaluate and compensate our mine management teams based on operating costs per ton at the mine level and on other non-financial measures, such as safety and environmental results.

Because we manage operating results on a regional basis, the reported profit at any individual mine may not be meaningful and is not indicative of the future economic prospects of the mine. An individual mine's profit is based on the contract shipments that are assigned to it by the central marketing group and the pricing under contracts for the sale of coal from a particular mine. Contracts are typically assigned based on the availability of coal and the cost of transporting the coal to the customer. Therefore, a mine that is assigned a lower-price contract will have a lower profit margin than a similar mine with similar costs that ships a nearly identical product under a higher-price contract. For more information about our sales and marketing, you should see "Sales, Marketing and Customers" below, and for more information about our contracts, you should see "Coal Supply Contracts" below.

The following table provides the location of and a summary of information regarding our principal mining complexes at December 31, 2005, the total sales associated with these complexes for the years ended December 31, 2003, 2004 and 2005 and the total reserves associated with these complexes at December 31, 2005:

Mining Complex (Location)	Captive Mine(s)(1)	Contract Mine(1)	Mining Equipment	Transportation	Tons Sold(2) 2003	2004	2005	Assigned Reserves (Million Tons)
					(Amounts in Millions)			
Central Appalachia:								
Arch of West Virginia (West Virginia)(3)	S	U	L, E	CSX	2.8	3.1	3.0	—
Campbells Creek (West Virginia) (3)	—	U	—	Barge	1.0	1.2	1.2	—
Coal-Mac (West Virginia)	S(2)	U, S	L, E	NS/CSX	2.1	2.6	3.2	14.9
Cumberland River (Virginia, Kentucky)	S(2), U(2)	U	L, C, HW	NS	1.5	1.6	2.3	24.3
Hobet 21 (West Virginia)(3)	S	U	D, L, S, C	CSX	5.2	4.6	4.2	—
Lone Mountain (Kentucky)	U(3)	—	C	NS/CSX	2.7	2.9	2.6	43.1
Mingo Logan (West Virginia)	U	U	LW, C	NS	5.5	5.1	4.7	9.3
Mountain Laurel (West Virginia)	U	—	C	CSX	—	—	—	131.0
Samples (West Virginia)(3)	S	U	D, L, S, HW	Barge/CSX	5.5	5.1	4.3	—
Powder River:								
Black Thunder (Wyoming)	S	—	D, S	UP/BN	62.6	75.1	87.6	1,512.6
Coal Creek (Wyoming)(4)	S	—	D, S	UP/BN	—	—	—	235.8
Western Bituminous:								
Arch of Wyoming (Wyoming)(5)	—	—	—	UP	0.5	0.2	—	—
Dugout Canyon (Utah)(6)	U	—	LW, C	UP	2.5	3.8	4.9	34.8
Skyline (Utah)(6)(7)	U	—	LW, C	UP	3.1	0.6	—	16.0
SUFCO (Utah)(6)	U	—	LW, C	UP	7.5	7.8	7.5	57.2
West Elk (Colorado)	U	—	LW, C	UP	6.5	6.2	5.9	73.9
Totals					109.0	119.9	131.2	2,152.9

S	=	Surface Mine	D	=	Dragline	UP	=	Union Pacific Railroad
U	=	Underground Mine	L	=	Loader/Truck	CSX	=	CSX Transportation
			S	=	Shovel/Truck	BN	=	Burlington Northern Railroad
			E	=	Excavator/Truck	NS	=	Norfolk Southern Railroad
			LW	=	Longwall			
			C	=	Continuous Miner			
			HW	=	Highwall Miner			

(1) Amounts in parenthesis indicate the number of captive and contract mines at the mining complex or location at December 31, 2005. Captive mines are mines which we own and operate on land owned or leased by us. Contract mines are mines which other operators mine for us under contracts on land owned or leased by us.

(2) Tons sold include tons of coal we purchased from third parties and processed through our loadout facilities. Coal purchased from third parties and processed through our loadout facilities approximated 2.2 million tons for 2005, 2.0 million tons for 2004 and 1.7 million tons for 2003. We have not included tons of coal we purchased from third parties that were not processed through our loadout facilities in the tons sold amounts above.

(3) In December 2005, we sold 100% of the stock of Hobet Mining, Apogee Coal Company and Catenary Coal Company, which include the Hobet 21, Arch of West Virginia, Samples and Campbells Creek mining complexes and associated reserves, to Magnum Coal Company.

(4) We idled the Coal Creek complex in 2000. We have announced that we will be restarting the Coal Creek mine in 2006.

(5) We placed the inactive surface mines at the Arch of Wyoming complex into reclamation mode in 2004.

(6) Prior to July 31, 2004, we owned a 65% interest in Canyon Fuel and accounted for it as an equity investment and our financial statements and tons sold were not consolidated into our financial statements. Subsequent to July 31, 2004 when we acquired the remaining 35% of Canyon Fuel, its financial results and tons sold are consolidated into our financial statements. Amounts shown represent 100% of Canyon Fuel's sales volume for all periods presented.

(7) In 2005, we resumed development mining at our Skyline complex, which we had idled in 2004.

We also incorporate by reference the information about the operating results of each of our segments for the years ended December 31, 2005, 2004 and 2003 contained in Note 23 — Segment Information to our consolidated financial statements included in our 2005 Annual Report to Stockholders.

Our Mining Methods

We employ mining methods designed to most efficiently mine coal according to the geological characteristics of our mines.

Underground Mining. Our underground mines are typically operated using one, or both, of two different techniques: continuous mining or longwall mining.

In 2005, 7% of our coal production came from underground mining operations generally using continuous mining techniques. Continuous mining is one type of room-and-pillar mining where rooms are cut into the coalbed, leaving a series of pillars, or columns, of coal to help support the mine and roof and direct the flow of air. Continuous mining equipment is used to cut the coal from the mining face. Generally, openings are driven 18 to 20 feet wide, and the pillars are generally rectangular in shape measuring 35 to 80 feet wide by 35 to 100 feet long. As mining advances, a grid-like pattern of entries and pillars is formed. Shuttle cars are used to transport coal to a conveyor belt for transport to the surface. When mining advances to the end of a panel, retreat mining may begin. In retreat mining, as much coal as is feasible is mined from the pillars that were created in advancing the panel, allowing the roof to collapse in a controlled fashion. When retreat mining is completed to the mouth of the panel, the mined panel is abandoned and generally sealed from the rest of the mine. The room-and-pillar method is often used to mine small coal blocks or thinner seams. Seam recovery ranges from 35% to 70%, with higher seam recovery rates applicable where retreat mining is combined with room-and-pillar mining.

In 2005, 12% of our coal production came from underground mining operations generally using longwall mining techniques. Longwall mining is the most productive underground mining method used in the United States. A rotating drum is trammed mechanically across the face of the coal, and a hydraulic system supports the roof of the mine while the drum advances through the coal. Chain conveyors then move the loosened coal to a standard underground mine conveyor system for delivery to the surface. Continuous miners are used to develop access to long rectangular blocks of coal that are then mined with longwall equipment, allowing controlled subsidence behind the retreating machinery. Longwall mining is highly productive and most effective for long blocks of medium to thick coal seams. Ultimate seam recovery of in-place reserves using longwall mining can reach 70%, which is generally much higher than the room-and-pillar underground mining techniques.

Surface Mining. Surface mining is used when coal is found close to the surface. In 2005, 73% of our coal production came from surface mines. This method involves the removal of overburden (earth and rock covering the coal) with heavy earth moving equipment and explosives, loading out the coal, replacing the overburden and topsoil after the coal has been excavated and reestablishing vegetation as well as making other improvements that have local community and environmental benefits. Seam recovery for surface mining is typically between 80% and 90%. We employ the following two types of surface mining methods: truck-and-shovel mining and dragline mining.

Truck-and-shovel mining is a surface mining method that uses large shovels, excavators or loaders to remove overburden which is then used to backfill pits after coal removal. Once exposed, shovels, excavators or loaders load the coal into haul trucks for transportation to a preparation plant or unit train loadout facility. Dragline mining is a surface mining method that uses large capacity draglines to remove overburden to expose the coal seams. Once exposed, shovels load coal into haul trucks for transportation to a preparation plan or unit train loadout facility. Seam recovery using the truck-and-shovel or dragline mining methods is typically 85% or more.

The remaining 8% of our coal production in 2005 was comprised of coal we purchased from third parties at prevailing market rates or pursuant to other contractual arrangements.

Our Mining Complexes

The following provides a description of the operating characteristics of our mining complexes. The amounts disclosed below for the total cost of property, plant and equipment and net book value of each mining complex do not include the costs or net book values of the coal reserves that we have assigned to any individual complex.

Central Appalachia. Our operations in the Central Appalachian region are located in southern West Virginia, eastern Kentucky and Virginia and included ten underground mines and five surface mines at December 31, 2005. During 2005, these mining complexes sold approximately 25.5 million tons of compliance, low-sulfur and metallurgical coal to customers in the United States and abroad. Metallurgical coal accounted for 2.2 million tons of total coal sales from these complexes in 2005. We control approximately 408.5 million tons of proven and probable coal reserves in Central Appalachia.

Coal-Mac. Our Coal-Mac operations consist of two production complexes, Ragland and Holden 22, located in Logan County and Mingo County, West Virginia. The Ragland and Holden 22 complexes mine contiguous properties with an estimated 42.9 million tons of assigned recoverable coal. The Ragland complex operates four production spreads as well as an overland belt and loadout system. Coal is trucked from the Ragland mine to one of two truck dumps where it is belted to a batch weigh loadout and direct shipped on the Norfolk Southern railroad. The Ragland loadout is capable of loading 5,000 tons per hour. The Holden 22 complex consists of a surface mine, a contract deep mine, a preparation plant and rail loadout system. Coal from the surface mine at our Holden 22 complex is transported via truck to the plant where it is either directly loaded or cleaned and then shipped on the CSX rail system. Coal from the underground mine at our Holden 22 complex is transported by conveyor belt to a stockpile where it is then trucked to the plant and cleaned prior to shipment. The Holden 22 preparation plant has a feed capacity of 600 raw tons per hour. The Holden 22 loadout is capable of loading 3,200 tons per hour. At December 31, 2005, the total cost of property, plant and equipment at our Coal-Mac operations was approximately $96.9 million and the net book value was approximately $57.9 million.

Cumberland River. The Cumberland River complex is an underground and surface mining complex located in Wise County, Virginia, and Letcher County, Kentucky. The complex is located on approximately 14,000 acres and contains approximately 26.9 million tons of assigned recoverable coal, primarily in Kentucky. The complex currently consists of three underground mines (two captive, one contract), two captive surface operations, two highwall miners (one captive, one contract), and one preparation plant and loadout facility. The preparation plant processes approximately two-thirds of the production, and approximately one-third of the production is shipped raw. All of the production is shipped through the loadout facility in Virginia via the Norfolk Southern railroad. The loadout facility is capable of loading a 12,500-ton unit train (108 cars) in less than four hours. The total cost of property, plant and equipment at the Cumberland River complex at December 31, 2005 was approximately $97.1 million, and the net book value was approximately $46.1 million.

Lone Mountain. The Lone Mountain complex is an underground operation located in Harlan County, Kentucky and Lee County, Virginia on approximately 15,000 acres containing approximately 43.1 million tons of assigned recoverable coal. The Lone Mountain complex currently consists of three underground mines operating seven continuous miner sections in total. The mined coal is conveyed from Kentucky to Virginia and processed through a preparation plant located near St. Charles, Virginia. The loadout facility is capable of shipping on the Norfolk Southern and CSX railroads. The loadout facility is capable of loading a 10,000 ton unit train in less than four hours. The total cost of property, plant and equipment at the Lone Mountain complex at December 31, 2005 was approximately $140.1 million, and the net book value was approximately $52.1 million.

Mingo Logan — Ben Creek. The Mingo Logan — Ben Creek mine is an underground operation located in Mingo County and Logan County, West Virginia on approximately 20,000 acres containing approximately 9.3 million tons of assigned recoverable coal. The Mingo Logan — Ben Creek complex currently consists of four continuous miners that support a longwall. The mined coal is processed through a preparation plant connected to the mine by a conveyor. The loadout on the Norfolk Southern railroad is connected to the mine by a second conveyor. The loadout facility is capable of loading a 15,000-ton unit train in less than four hours. The total cost of property, plant and equipment at the Mingo Logan — Ben Creek complex at December 31, 2005 was approximately $131.6 million, and the net book value was approximately $17.7 million.

Mountain Laurel Complex. The Mountain Laurel complex is an underground operation that we are developing in Logan County, West Virginia on approximately 9,000 acres containing approximately 170.3 million tons of assigned recoverable coal. The Mountain Laurel complex will consist of three to six continuous miners that support a longwall. Mine development began in July 2004, and the first continuous miner unit began development in late September 2005. Two more continuous miner units will be placed into production in the first half of 2006. Full production will not be realized until the longwall is placed into service in the second half of 2007. All raw coal is belted and processed through a state-of-the-art 2,100 ton per hour preparation plant located at the mine. The loadout facility is on the CSX railroad and is connected to the plant by a 5,000 ton per hour conveyor. The loadout facility is scheduled to be placed into service in the third quarter of 2006 and will be capable of loading a 15,000-ton unit train in less than four hours. The total cost of property, plant and equipment at the Mountain Laurel complex at December 31, 2005 is approximately $98.4 million.

Powder River Basin. Our operations in the Powder River Basin are located in Wyoming and include two surface mines. During 2005, these mining complexes sold approximately 87.6 million tons of compliance, low-sulfur coal to customers in the United States. We control approximately 1.9 billion tons of proven and probable coal reserves in the Powder River Basin.

Black Thunder. The Black Thunder mine is a surface mining complex located in Campbell County, Wyoming. The mine complex is located on approximately 24,000 acres with a majority of coal controlled by federal and state leases with a small amount of private fee coal acreage. The total assigned recoverable coal reserves are estimated to be approximately 1.5 billion tons. The mine currently consists of six active pit areas, two owned loadout facilities and one leased loadout facility. All of the coal is shipped raw to customers, and there are no preparation plant processes. All of the production is shipped via the Burlington Northern and Union Pacific railroads. The loadout facilities are capable of loading a 14,500-ton unit train in two to three hours. The total cost of property, plant and equipment at the Black Thunder mine at December 31, 2005 was approximately $503.4 million and the net book value was approximately $328.0 million.

Coal Creek. The Coal Creek mine is a surface mining complex located in Campbell County, Wyoming. The mine complex is located on approximately 10,000 acres with a majority of coal controlled by federal and state leases and a small amount of private fee coal acreage. The total assigned recoverable coal reserves are estimated to be 239.1 million tons. The mine currently consists of no active pit areas, and one loadout facility. Although the mine has been idle since 2000, we plan to reactivate production in 2006. All of the coal is shipped raw to customers, and there are no preparation plant processes. All of the production is shipped via the Burlington Northern and Union Pacific railroads. The loadout facility is capable of loading a 14,000-ton unit train in less than three hours. The total cost of property, plant and equipment at the Coal Creek mine at December 31, 2005 was approximately $49.4 million, and the net book value was approximately $35.0 million. The Coal Creek mine had no coal production during 2005.

Western Bituminous Region. Our operations in the Western Bituminous Region are located in southern Wyoming, Colorado and Utah and include four underground mines and four surface mines. All of the surface mines are in reclamation mode. During 2005, these mining complexes sold approximately 18.3 million tons of compliance, low-sulfur coal to customers in the United States. We control approximately 469.2 million tons of proven and probable coal reserves in the Western Bituminous Region.

Arch of Wyoming. The Arch of Wyoming mining complex is a surface mining complex located in Carbon County, Wyoming. The complex consists of four inactive surface mines that are in the final process of reclamation. The complex also consists of an undeveloped mining area called Carbon Basin that has recently been permitted for operations. The inactive surface mines under reclamation are located on approximately 58,000 acres with a majority of coal controlled by federal, private and state leases. The Carbon Basin mine complex is located on approximately 13,000 acres with a majority of coal controlled by federal, private and state leases. The total assigned recoverable coal reserves at Carbon Basin are estimated to be 194.1 million tons with a majority of the reserves recoverable by underground mining methods. The total cost of property, plant and equipment at the Arch of Wyoming complex at December 31, 2005 was approximately $40.8 million, and the net book value was approximately $3.1 million. The Arch of Wyoming complex had no coal production during 2005.

Dugout Canyon. The Dugout Canyon mine is an underground mine located in Carbon County, Utah. The mine is located on approximately 9,000 acres with a majority of coal controlled by federal and state leases with a small amount of private fee coal acreage. The total assigned recoverable coal reserves are estimated to be 39.7 million tons. The mine currently consists of a single longwall and two continuous miner sections, and one truck loadout facility. All of the coal is shipped raw to customers, and there are no preparation plant processes. All of the production is shipped via the Union Pacific railroad. The mine loadout facility is capable of loading about 20,000 tons per day into highway trucks. Train shipments are handled by a third party loadout that can load an 11,000-ton train in less than three hours. The total cost of property, plant and equipment at the Dugout Canyon mine at December 31, 2005 was approximately $81.0 million, and the net book value was approximately $50.9 million.

Skyline. The Skyline mine is an underground mine located in Carbon and Emery Counties, Utah. The mine is located on approximately 13,000 acres with a majority of coal controlled by federal leases with a small amount on private and county leases. The total assigned recoverable coal reserves are estimated to be 16.0 million tons. The mine currently consists of two continuous miner sections and a longwall that will be operational in mid-2006 and one loadout facility. All of the coal can be shipped raw to customers, and there are no preparation plant processes. All of the production is shipped via the Union Pacific railroad or directly to customers by highway trucks. The loadout facility is capable of loading a 12,000-ton unit train in less than four hours. The total cost of property, plant and equipment at the Skyline mine at December 31, 2005 was approximately $81.3 million and the net book value was approximately $46.4 million.

Sufco. The Sufco mine is an underground mine located in Sevier County, Utah. The mine is located on approximately 27,000 acres with a majority of coal controlled by federal and state leases with a small amount of private fee coal acreage. The total assigned recoverable coal reserves are estimated to be 89.7 million tons. The mine currently consists of a single longwall and two continuous miner sections, and one loadout facility. All of the coal is shipped raw to customers without preparation plant processing. All of the production is shipped via the Union Pacific railroad or directly to customers by highway trucks. The loadout facility, located approximately 90 miles from the mine, is capable of loading an 11,000-ton unit train in less than three hours.

The total cost of property, plant and equipment at the Sufco Mine at December 31, 2005 was approximately $121.6 million, and the net book value was approximately $45.6 million.

West Elk. The West Elk mine is an underground mine located in Gunnison County, Colorado. The mine is located on approximately 15,000 acres with a majority of coal controlled by federal and state leases with a small amount of private fee coal acreage. The total assigned recoverable coal reserves are estimated to be 129.8 million tons. The mine currently consists of a single longwall and three continuous miner sections, and one loadout facility. All of the coal is shipped raw to customers, and there are no preparation plant processes. All of the production is shipped via the Union Pacific railroad. The loadout facility is capable of loading an 11,000-ton unit train in less than three hours. The total cost of property, plant and equipment at the West Elk mine at December 31, 2005 was approximately $173.5 million, and the net book value was approximately $71.9 million.

Transportation

We ship our coal to customers by means of railroad cars, river barges or trucks, or a combination of these means of transportation. We also ship our coal to Atlantic coast terminals for shipment to domestic and international customers. As is customary in the industry, once the coal is loaded onto the barge or rail car, our customers are typically responsible for the freight costs to the ultimate destination. Transportation costs borne by the customer vary greatly based on each customer's proximity to the mine and our proximity to the loadout facilities.

Our Arch Coal Terminal is located in Catlettsburg, Kentucky on a 111-acre site on the Big Sandy River above its confluence with the Ohio River. The terminal provides coal and other bulk material storage and can load and offload river barges at the facility. The terminal can provide up to 500,000 tons of storage and can process up to six million tons of coal annually. In addition to providing storage and transloading services, the terminal provides maintenance and other services.

In addition, our subsidiaries together own a 17.5% interest in Dominion Terminal Associates, which leases and operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia. The facility has a rated throughput capacity of 20 million tons of coal per year and ground storage capacity of approximately 1.7 million tons. The facility serves international customers, as well as domestic coal users located on the eastern seaboard of the United States.

Sales, Marketing and Customers

Coal prices are influenced by a number of factors and vary dramatically by region. As a result of these regional characteristics, prices of coal within a given major coal producing region tend to be relatively consistent. The two principal components of the price of coal within a region are the price of coal at the mine, which is influenced by market conditions and by mine operating costs, coal quality, and transportation costs involved in moving coal from the mine to the point of use. In addition to supply and demand factors, the price of coal at the mine is influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. It is generally cheaper to mine coal seams that are thick and located close to the surface than to mine thin underground seams. Within a particular geographic region, underground mining, which is the mining method we use in the Western Bituminous region and also a method we use at certain mines in Central Appalachia, is generally more expensive than surface mining, which is the mining method we use in the Powder River Basin and also for certain of our Central Appalachian mines. This is the case because of the higher capital costs, including costs for modern mining equipment and construction of extensive ventilation systems and higher labor costs due to lower productivity associated with underground mining.

In addition to the cost of mine operations, the price of coal is also a function of quality characteristics such as heat value, sulfur, ash and moisture content. Higher carbon and lower ash content generally result in higher prices.

Management, including our chief executive officer and chief operating officer, reviews and makes resource allocations based on the goal of maximizing our profits in light of the comparative cost structures of our various operations. Because our customers purchase coal on a regional basis, coal can generally be sourced from several different locations within a region. Once we have a contractual commitment to purchase an amount of coal at a certain price, our central marketing group assigns contract shipments to our various mines which can be used to source the coal in the appropriate region.

Coal Supply Contracts

We sell coal both under long-term contracts, the terms of which are greater than 12 months, and on a current market or spot basis. When our coal sales contracts expire or are terminated, we are exposed to the risk of having to sell coal into the spot market, where demand is variable and prices are subject to greater volatility. Historically, the price of coal sold under long-term contracts has exceeded prevailing spot prices for coal. However, in the past several years new contracts have been priced at or near existing spot rates.

The terms of our coal sales contracts result from bidding and extensive negotiations with customers. Consequently, the terms of these contracts typically vary significantly in many respects, including price adjustment features, provisions permitting renegotiation or modification of coal sale prices, coal quality requirements, quantity parameters, flexibility and adjustment mechanisms, permitted sources of supply, treatment of environmental constraints, options to extend, and force majeure, suspension, termination and assignment provisions.

Provisions permitting renegotiation or modification of coal sale prices are present in many of our more recently negotiated long-term contracts and usually occur midway through a contract or every two to three years, depending upon the length of the contract. In some circumstances, customers have the option to terminate the contract if prices have increased by a specified percentage from the price at the commencement of the contract or if the parties cannot agree on a new price. The term of sales contracts has decreased significantly over the last two decades as competition in the coal industry has increased and, more recently, as electricity generators have prepared themselves for federal Clean Air Act requirements and the deregulation of their industry.

We also participate in the “over the counter market” for a small portion of our sales.

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal quality, transportation costs from the mine to the customer and the reliability of supply. Our principal competitors include Alpha Natural Resources, Inc., CONSOL Energy Inc., Foundation Coal Holdings, Inc., International Coal Group, Inc., James River Coal Company, Kennecott Energy Company, Massey Energy Company, Magnum Coal Company and Peabody Energy Corp. Some of these coal producers are larger and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in the Central Appalachian and Powder River Basin areas and our other market regions. As the price of domestic coal increases, we may also begin to compete with companies that produce coal from one or more foreign countries, such as Columbia and Venezuela.

Additionally, coal competes with other fuels such as petroleum, natural gas, hydropower and nuclear energy for steam and electrical power generation. Over time, costs and other factors, such as safety and environmental consideration, relating to these alternative fuels may affect the overall demand for coal as a fuel.

Geographic Data

We market our coal principally to electric utilities in the United States. Coal sales to foreign customers approximated $166.0 million for 2005, $134.0 million for 2004 and $45.8 million for 2003.

Environmental Matters

Our operations, like operations of other companies engaged in similar businesses, are subject to regulation by federal, state and local authorities on matters such as the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration activities involving our mining properties, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, air quality standards, protection of wetlands, endangered plant and wildlife protection, limitations on land use, storage of petroleum products and substances that are regarded as hazardous under applicable laws and management of electrical equipment containing polychlorinated biphenyls, which we refer to as PCBs.

Additionally, the electric generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our coal. The possibility exists that new legislation or regulations may be adopted or that the enforcement of existing laws could become more stringent, either of which may have a significant impact on our mining operations or our customers' ability to use coal and may require us or our customers to significantly change operations or to incur substantial costs.

While it is not possible to quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. Federal and state mining laws and regulations require us to obtain surety bonds to guarantee performance or payment of certain long-term obligations including mine closure and reclamation costs, federal and state workers' compensation benefits, coal leases and other miscellaneous obligations. Compliance with these laws has substantially increased the cost of coal mining for all domestic coal producers.

The following is a summary of the various federal and state environmental and similar regulations that have a material impact on our operations:

Clean Air Act. The federal Clean Air Act and similar state and local laws, which regulate emissions into the air, affect coal mining and processing operations primarily through permitting and emissions control requirements. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the emissions from coal-fired industrial boilers and power plants, which are the largest end-users of our coal. These regulations can take a variety of forms, as explained below.

The Clean Air Act imposes obligations on the United States Environmental Protection Agency, which we refer to as the EPA, and the states to implement regulatory programs that will lead to the attainment and maintenance of EPA-promulgated ambient air quality standards. EPA has promulgated ambient air quality standards for a number of air pollutants, including standards for sulfur dioxide, particulate matter, nitrogen oxides and ozone, which are associated with the combustion of coal. Owners of coal-fired power plants and industrial boilers have been required to expend considerable resources in an effort to comply with these ambient air quality standards. In particular, coal-fired power plants will be affected by state regulations designed to achieve attainment of the ambient air quality standard for ozone, which may require significant expenditures for additional emissions control equipment needed to meet the current national ambient air standard for ozone. Ozone is produced by the combination of two primary precursor pollutants: volatile organic compounds and nitrogen oxides. Nitrogen oxides are a by-product of coal combustion. Accordingly, emissions control requirements for new and expanded coal-fired power plants and industrial boilers will continue to become more demanding in the years ahead.

In July 1997, the EPA adopted more stringent ambient air quality standards for ozone and fine particulate matter ($PM_{2.5}$, which can be formed in the air from gaseous emissions of sulfur dioxide and nitrogen oxides, both of which are associated with coal combustion). In a February 2001 decision, the United States Supreme Court largely upheld the EPA's position, although it remanded the EPA's ozone implementation policy for further consideration. On remand, the Court of Appeals for the D.C. Circuit affirmed the EPA's adoption of these more stringent ambient air quality standards. As a result of the finalization of these standards, states that are not in attainment for these standards will have to revise their State Implementation Plans to include provisions for the control of ozone precursors and/or particulate matter. In April 2004, the EPA issued final nonattainment designations for the eight-hour ozone standard, and, in December 2004, issued the final nonattainment designations for $PM_{2.5}$. On April 30, 2004, the EPA published the final Phase 1, 8-hour ozone implementation rule, and on November 29, 2005, the EPA published its final Phase 2, 8-hour ozone implementation rule. On November 1, 2005, the EPA published its proposed $PM_{2.5}$ implementation rule. States will have to submit their 8-hour ozone and $PM_{2.5}$ SIPs by April 2007 and April 2008, respectively, and are likely to require electric power generators to reduce further sulfur dioxide, nitrogen oxide and particulate matter emissions, particularly in designated nonattainment areas. Both the nonattainment designations and the 8-hour implementation rule are the subject of litigation. Depending upon the outcome of the litigation, the potential need to achieve such emissions reductions could result in reduced coal consumption by electric power generators. Thus, future regulations regarding ozone, particulate matter and other pollutants could restrict the market for coal and our development of new mines. This in turn may result in decreased production and a corresponding decrease in our revenues. The EPA is currently obligated under a consent decree to sign final rulemakings concerning the particulate matter National Ambient Air Quality Standards (NAAQS) in September 2006, and proposed and final rulemakings concerning the ozone NAAQS in March 2007 and December 2007, respectively. On January 17, 2006, the EPA published a new and more stringent proposed NAAQS for $PM_{2.5}$ and inhalable course particles ($PM_{10-2.5}$), which are smaller than 10 micrometers in diameter but larger than $PM_{2.5}$. These and other ambient air quality standards could restrict the market for coal and the development of new mines.

In October 1998, the EPA finalized a rule that requires 19 states in the Eastern United States that have ambient air quality programs to make substantial reductions in nitrogen oxide emissions. Under the rule, which is commonly known as the NOx SIP Call, Phase I states are required to reduce nitrogen oxide emissions by 2004, and Phase II states are required to reduce nitrogen oxide emissions by 2007. The Court of Appeals for the D.C. Circuit largely upheld the NOx SIP Call, and affected states have adopted and submitted to the EPA NOx SIP Call rules. As a result, many power plants and large industrial sources have been or will be required to install additional control measures. The installation of these control measures could make it more costly to operate coal-fired units and, depending upon the requirements of individual SIPs, could make coal a less attractive fuel.

The EPA has also initiated a regional haze program designed to protect and to improve visibility at and around National Parks, National Wilderness Areas and International Parks, particularly those located in the southwest and southeast United States. This program restricts the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas. In June 2005, EPA finalized amendments to the regional haze rules or Clean Air Visibility Rule (CAVR) which will require certain existing coal-fired power plants to install Best Available Retrofit Technology (BART) to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, and particulate matter. By imposing limitations upon the placement and construction of new coal-fired power plants and BART requirements on existing coal-fired power plants, the EPA's regional haze program could affect the future market for coal. The EPA's CAVR is the subject of litigation in the Court of Appeals for the D.C. Circuit. In addition, in August 2005, the EPA published a proposed emissions trading rule as an alternative to BART.

New regulations concerning the routine maintenance provisions of the New Source Review program were published in October 2003. Fourteen states, the District of Columbia and a number of municipalities filed lawsuits challenging these regulations, and in December 2003 the Court stayed the effectiveness of these rules. In July 2004 the EPA granted a petition to reconsider the legal basis for the routine maintenance provisions, and the litigation was suspended while the rule was being reconsidered. In June 2005, the EPA issued its final response, which does not change the rule. The case has been returned to the D.C. Circuit's active docket, and final briefs were due in January 2006. In addition, in October 2005, the EPA published a proposed rule requiring an hourly emissions test for power plants for determining an emissions increase under the New Source Review program. By imposing requirements for the construction and modification of coal-fired units, these New Source Review reforms could make coal a less attractive fuel.

In January 2004, the EPA Administrator announced that the EPA would be taking new enforcement actions against utilities for violations of the existing New Source Review requirements, and shortly thereafter, the EPA issued enforcement notices to several electric utility companies. Additionally, the U.S. Department of Justice, on behalf of the EPA, has filed lawsuits against several investor-owned electric utilities for alleged violations of the Clean Air Act. The EPA claims that these utilities have failed to obtain permits required under the Clean Air Act for alleged major modifications to their power plants. We supply coal to some of the currently affected utilities, and it is possible that other of our customers will be sued. These lawsuits could require the utilities to pay penalties and install pollution control equipment or undertake other emission reduction measures, which could adversely impact their demand for coal.

In March 2004, North Carolina submitted to the EPA a petition under § 126 of the Clean Air Act. In its petition, North Carolina alleges that power plants in 12 states contribute significantly to nonattainment in, and interfere with maintenance by, North Carolina with respect to the PM2.5 NAAQS. In addition, North Carolina alleges that power plants in five states contribute significantly to nonattainment in, and interfere with maintenance by, North Carolina with respect to the 8-hour ozone NAAQS. In August 2005, the EPA published a proposed rule in response to North Carolina's §126 Petition. For ozone, the EPA is proposing to deny North Carolina's petition. For PM2.5, the EPA is proposing to deny North Carolina's petition as to Michigan and Illinois and with respect to the other targeted States is proposing two options. Under Option 1, the EPA is proposing to deny North Carolina's petition if the EPA issues its Clean Air Interstate Rule (CAIR) Federal Implementation Plan (FIP) by March 15, 2006, and under Option 2, the EPA is proposing to grant North Carolina's petition if the EPA does not issue its CAIR FIP by March 15, 2006. Pursuant to a consent decree, the EPA is obligated to promulgate its final rule on North Carolina's § 126 petition by March 15, 2006. If the EPA grants North Carolina's § 126 petition, then coal-fired power plants in Alabama, Georgia, Indiana, Kentucky, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, and West Virginia must reduce their SO_2 and NOX emissions by March 15, 2009. If finalized, the EPA's proposed response to North Carolina's § 126 petition could adversely impact the coal needs of power plants in the affected states.

In March 2005, the EPA issued three new rules that will impact coal-fired power plants. These are (i) the Clean Air Interstate Rule (CAIR), which caps emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) in the eastern United States; (ii) the mercury de-listing rule, which de-lists power plants as a source of mercury and other toxic air pollutants and rescinds a finding made in 2000 that it was appropriate and necessary to regulate power plants under Section 112(c) of the Clean Air Act; and (iii) the Clean Air Mercury Rule (CAMR), which caps and reduces mercury emissions from coal-fired power plants. Both CAIR and CAMR provide power plant operators a market-based system in which plants that exceed federal requirements can sell pollution credits to plant operators who need more time to comply with the stricter rules. CAIR requires reductions of SO_2 and/or NOx emissions across 28 eastern states and the District of Columbia and, when fully implemented in 2015, CAIR will reduce SO_2emissions in these states by over 70 percent and NOx emissions by over 60 percent from 2003 levels. Under the new mercury emissions rule, mercury emissions from coal-fired power plants will not be regulated as a Hazardous Air Pollutant, which would require installation of Maximum Available Control Technology (MACT). Instead, using the cap-and-trade system, these plants will have until 2010 to cut mercury emission levels to 38 tons a year from 48 tons and until 2018 to bring that level down to 15 tons, a 69 percent reduction. Utility analysts have estimated meeting the goals for SO_2 and NOx will cost power generators approximately $50 billion to install the required filtration systems, or "scrubbers," on their smokestacks, but these controls are expected to also reduce the mercury emissions to the targeted levels in 2010. Additional controls will be required to meet the mercury emissions cap in 2018. The CAIR, mercury de-listing rule, and the CAMR are the subject of ongoing litigation. If the mercury de-listing rule is not upheld, then the CAMR and its cap-and-trade program may also be rejected in favor of the MACT approach. If CAIR and CAMR survive the legal challenges, or if a MACT requirement is imposed for mercury emissions, the additional costs that may be associated with operating coal-fired power generation facilities due to the implementation of these new rules may render coal a less attractive fuel source.

Other Clean Air Act programs are also applicable to power plants that use our coal. For example, the acid rain control provisions of Title IV of the Clean Air Act require a reduction of sulfur dioxide emissions from power plants. Because sulfur is a natural component of coal, required sulfur dioxide reductions can affect coal mining operations. Title IV imposes a two-phase approach to the implementation of required sulfur dioxide emissions reductions. Phase I, which became effective in 1995, regulated the sulfur dioxide emissions levels from 261 generating units at 110 power plants and targeted the highest sulfur dioxide emitters. Phase II, implemented January 1, 2000, made the regulations more stringent and extended them to additional power plants, including all power plants of greater than 25 megawatt capacity. Affected electric utilities can comply with these requirements by:

- burning lower sulfur coal, either exclusively or mixed with higher sulfur coal;
- installing pollution control devices such as scrubbers, which reduce the emissions from high sulfur coal;
- reducing electricity generating levels; or
- purchasing or trading emissions credits.

Specific emissions sources receive these credits, which electric utilities and industrial concerns can trade or sell to allow other units to emit higher levels of sulfur dioxide. Each credit allows its holder to emit one ton of sulfur dioxide.

Other proposed initiatives may have an effect upon coal operations. One such proposal is the Bush Administration's Clear Skies legislation. As proposed, this legislation is designed to reduce emissions of sulfur dioxide, nitrogen oxides, and mercury from power plants. Other so-called mutli-pollutant bills, which would regulate additional air pollutants, have been proposed by various members of Congress. While the details of all of these proposed initiatives vary, there appears to be a movement towards increased regulation of emissions, including carbon dioxide and mercury. If such initiatives were to become law, power plants could choose to shift away from coal as a fuel source to meet these requirements.

Mine Health and Safety Laws. Stringent safety and health standards have been imposed by federal legislation since the adoption of the Mine Safety and Health Act of 1969. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Safety and Health Act of 1969, imposes comprehensive safety and health standards on all mining operations. In addition, as part of the Mine Safety and Health Acts of 1969 and 1977, the Black Lung Act requires payments of benefits by all businesses conducting current mining operations to coal miners with black lung and to some survivors of a miner who dies from this disease. The states in which we operate also have mine safety and health laws. In January 2006, the West Virginia legislature amended its mine safety and health laws to require mine operators to notify emergency response coordinators promptly after serious accidents and provide miners with wireless tracking and communications devices and self-contained self-rescue breathing equipment. Federal legislation has been proposed along the same lines but has not been yet passed, and other states are considering similar laws.

Surface Mining Control and Reclamation Act. The Surface Mining Control and Reclamation Act, which we refer to as SMCRA, establishes operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities. In conjunction with mining the property, we are contractually obligated under the terms of our leases to comply with all laws, including SMCRA and equivalent state and local laws. These obligations include reclaiming and restoring the mined areas by grading, shaping, preparing the soil for seeding and by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan.

SMCRA also requires us to submit a bond or otherwise financially secure the performance of our reclamation obligations. The earliest a reclamation bond can be completely released is five years after reclamation has been achieved. Federal law and some states impose on mine operators the responsibility for repairing the property or compensating the property owners for damage occurring on the surface of the property as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. In addition, the Abandoned Mine Lands Act, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is $0.35 per ton of coal produced from surface mines and $0.15 per ton of coal produced from underground mines.

We also lease some of our coal reserves to third party operators. Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent mine lessees and other third parties could potentially be imputed to other companies that are deemed, according to the regulations, to have “owned” or “controlled” the mine operator. Sanctions against the “owner” or “controller” are quite severe and can include civil penalties, reclamation fees and reclamation costs. We are not aware of any currently pending or asserted claims against us asserting that we “own” or “control” any of our lessees’ operations.

Framework Convention on Global Climate Change. The United States and more than 160 other nations are signatories to the 1992 Framework Convention on Global Climate Change, commonly known as the Kyoto Protocol, that is intended to limit or capture emissions of greenhouse gases such as carbon dioxide and methane. The U.S. Senate has neither ratified the treaty commitments, which would mandate a reduction in U.S. greenhouse gas emissions, nor enacted any law specifically controlling greenhouse gas emissions, and the Bush Administration has withdrawn support for this treaty. Nonetheless, future regulation of greenhouse gases could occur either pursuant to future U.S. treaty obligations or pursuant to statutory or regulatory changes under the Clean Air Act. Efforts to control greenhouse gas emissions could result in reduced demand for coal if electric power generators switch to lower carbon sources of fuel.

West Virginia Antidegradation Policy. In January 2002, a number of environmental groups and individuals filed suit in the U.S. District Court for the Southern District of West Virginia to challenge the EPA’s approval of West Virginia’s antidegradation implementation policy. Under the federal Clean Water Act, state regulatory authorities must conduct an antidegradation review before approving permits for the discharge of pollutants to waters that have been designated as high quality by the state. Antidegradation review involves public and intergovernmental scrutiny of permits and requires permittees to demonstrate that the proposed activities are justified in order to accommodate significant economic or social development in the area where the waters are located. In August 2003, the Southern District of West Virginia vacated the EPA’s approval of West Virginia’s anti-degradation procedures, and remanded the matter to the EPA. On March 29, 2004, the EPA Regions III sent a letter to the West Virginia Department of Environmental Protection that approved portions of the state’s anti-degradation program, denied approval of portions pending further study, and recommended removal of certain language on the state’s regulations. Depending upon the outcome of the review, the issuance or re-issuance of Clean Water Act permits to us may be delayed or denied, and may increase the costs, time and difficulty associated with obtaining and complying Clean Water Act permits for surface mining operations.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, which we refer to as CERCLA, and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could implicate the liability provisions of the statute. Thus, coal mines that we currently own or have previously owned or operated, and sites to which we sent waste materials, may be subject to liability under CERCLA and similar state laws. In particular, we may be liable under CERCLA or similar state laws for the cleanup of hazardous substance contamination at sites where we own surface rights.

Mining Permits and Approvals. Mining companies must obtain numerous permits that strictly regulate environmental and health and safety matters in connection with coal mining, some of which have significant bonding requirements. In connection with obtaining these permits and approvals, we may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations. Regulations also provide that a mining permit can be refused or revoked if an officer, director or a shareholder with a 10% or greater interest in the entity is affiliated with another entity that has outstanding permit violations. Thus, past or ongoing violations of federal and state mining laws could provide a basis to revoke existing permits and to deny the issuance of additional permits.

Regulatory authorities exercise considerable discretion in the timing of permit issuance. Also, private individuals and the public at large possess rights to comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need for our mining operations may not be issued, or, if issued, may not be issued in a timely fashion, or may involve requirements that may be changed or interpreted in a manner which restricts our ability to conduct our mining operations or to do so profitably.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including us, must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically we submit the necessary permit applications several months before we plan to begin mining a new area. Some of our required permits are becoming increasingly more difficult and expensive to obtain and the application review processes are taking longer to complete and becoming increasingly subject to challenge. As a result, we cannot be sure that we will not experience difficulty in obtaining mining permits in the future.

Future legislation and administrative regulations may emphasize the protection of the environment and, as a consequence, the activities of mine operators, including us, may be more closely regulated. Legislation and regulations, as well as future interpretations of existing laws, may also require substantial increases in equipment expenditures and operating costs, as well as delays, interruptions or the termination of operations. We cannot predict the possible effect of such regulatory changes.

Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Endangered Species. The federal Endangered Species Act and counterpart state legislation protects species threatened with possible extinction. Protection of endangered species may have the effect of prohibiting or delaying us from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species. A number of species indigenous to our properties are protected under the Endangered Species Act. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our ability to mine coal from our properties in accordance with current mining plans.

Other Environmental Laws. We are required to comply with numerous other federal, state and local environmental laws in addition to those previously discussed. These additional laws include, for example, the Resource Conservation and Recovery Act, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right-to-Know Act. We believe that we are in substantial compliance with all applicable environmental laws.

Definitions of Select Mining Terms

Assigned Reserves. Recoverable coal reserves that have been designated for mining by a specific operation.

Auger Mining. Auger mining employs a large auger, which functions much like a carpenter’s drill. The auger bores into a coal seam and discharges coal out of the spiral onto waiting conveyor belts. After augering is completed, the openings are reclaimed. This method of mining is usually employed to recover any additional coal left in deep overburden areas that cannot be reached economically by other types of surface mining.

Btu — British Thermal Unit. A measure of the energy required to raise the temperature of one pound of water one degree of Fahrenheit.

Coal Seam. A bed or stratum of coal.

Coal Washing. The process of removing impurities, such as ash and sulfur-based compounds, from coal.

Compliance Coal. Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btus, which is equivalent to 0.72% sulfur per pound of 12,000 Btu coal. Compliance coal requires no mixing with other coals or use of sulfur dioxide reduction technologies by generators of electricity to comply with the requirements of the Clean Air Act.

Continuous Miner. A machine used in underground mining to cut coal from the seam and load it onto conveyors or into shuttle cards in a continuous operation.

Continuous Mining. One of two major underground mining methods now used in the United States. This process utilizes a continuous miner.

Dragline. A large machine used in the surface mining process to remove the overburden, or layers of earth and rock, covering a coal seam. The dragline has a large bucket suspended from the end of a long boom. The bucket, which is suspended by cables, is able to scoop up great amounts of overburden as it is dragged across the excavation area.

Excavator-and-Loader Mining. A form of surface mining in which large excavators remove overburden from above the coal seam. The overburden is loaded into trucks and hauled to a valley fill or back-stacked on previously mined areas.

Highwall Mining. Highwall mining employs a large machine with a continuous miner head. The head cuts into a coal seam and discharges coal out onto waiting conveyor belts. After highwall mining is completed, the openings are reclaimed. This method of mining is usually employed to recover any additional coal left in deep overburden areas that cannot be reached economically by other types of surface mining.

Longwall Mining. One of two major underground coal mining methods now used in the United States. This method employs a rotating drum, which is pulled mechanically back and forth across a face of coal that is usually several hundred feet long. The loosened coal falls onto a conveyor for removal from the mine. Longwall operations include a hydraulic roof support system that advances as mining proceeds, allowing the roof to fall in a controlled manner in areas already mined.

Low-Sulfur Coal. Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btus.

Metallurgical Coal. The various grades of coal suitable for distillation into carbon in connection with the manufacture of steel. Also known as “met” coal.

Preparation Plant. A preparation plant is a facility for crushing, sizing and washing coal to prepare it for use by a particular customer. The washing process has the added benefit of removing some of the coal’s sulfur content.

Probable Reserves. Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart; therefore, the degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Proven Reserves. Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well established.

Reclamation. The restoration of land and environmental values to a mining site after the coal is extracted. Reclamation operations are usually underway where the coal has already been taken from a mine, even as mining operations are taking place elsewhere at the site. The process commonly includes “recontouring” or shaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers.

Recoverable Reserves. The amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods and under current law.

Reserves. That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

Spot Market. Sales of coal under an agreement for shipments over a period of less than one year.

Steam Coal. Coal used in steam boilers to produce electricity.

Surface Mine. A mine in which the coal lies near the surface and can be extracted by removing overburden.

Tons. References to a "ton" mean a "short" or net tonne, which is equal to 2,000 pounds.

Truck-and-Loader Mining. A form of surface mining in which endloaders remove overburden from above the coal seam. The overburden is loaded into trucks and hauled to a valley fill or back-stacked on previously mined areas.

Truck-and-Shovel Mining. An open-cast method of mining that uses large shovels to remove overburden, which is used to backfill pits after coal removal.

Unassigned Reserves. Recoverable coal reserves that have not yet been designated for mining by a specific operation.

Underground Mine. Also known as a "deep" mine. Usually located several hundred feet below the earth's surface, an underground mine's coal is removed mechanically and transferred by shuttle car or conveyor to the surface.

Employees

As of March 1, 2006, we employed a total of approximately 3,700 persons, approximately 200 of whom were represented by the Scotia Employees Association. We believe that our relations with all employees are good.

Executive Officers

The following is a list of our executive officers, their ages and their positions and offices during the last five years:

C. Henry Besten, Jr., 58, is our Senior Vice President — Strategic Development and has served in such capacity since December 2002. Mr. Besten is also President of our Arch Energy Resources, Inc. subsidiary and has served in that capacity since July 1997. From July 1997 to December 2002, Mr. Besten served as our Vice President — Strategic Marketing. Mr. Besten also served as our Acting Chief Financial Officer from December 1999 to November 2000.

John W. Eaves, 48, is our Executive Vice President and Chief Operating Officer and has served in such capacity since December 2002. Mr. Eaves has also been a director since February 2006. From February 2000 to December 2002, Mr. Eaves served as our Senior Vice President — Marketing and from September 1995 to December 2002 as President of our Arch Coal Sales Company, Inc. subsidiary. Mr. Eaves also served as our Vice President — Marketing from July 1997 through February 2000. Mr. Eaves serves on the board of directors of ADA-ES, Inc.

Sheila B. Feldman, 51, is our Vice President — Human Resources and has served in such capacity since February 2003. From 1997 to February 2003, Ms. Feldman was the Vice President — Human Resources and Public Affairs of Solutia Inc.

Robert G. Jones, 49, is our Vice President — Law, General Counsel and Secretary and has served in such capacity since March 2000. Mr. Jones served as our Assistant General Counsel from July 1997 through February 2000 and as Senior Counsel from August 1993 to July 1997.

Steven F. Leer, 53, is our President and Chief Executive Officer and a director and has served in such capacity since 1992. Mr. Leer also serves on the boards of the Norfolk Southern Corporation, USG Corp., the Western Business Roundtable and the University of the Pacific. Mr. Leer is a past chairman and continues to serve on the boards of the Center for Energy and Economic Development, the National Coal Council and the National Mining Association.

Robert J. Messey, 60, is our Senior Vice President and Chief Financial Officer and has served in such capacity since December 2000. Mr. Messey serves on the board of directors of Baldor Electric Company and Stereotaxis, Inc.

David B. Peugh, 51, is our Vice President — Business Development and has served in such capacity since 1993.

Deck S. Slone, 42, is our Vice President — Investor Relations and Public Affairs and has served in such capacity since 2001. Mr. Slone was named one of our senior officers in August 2005. Mr. Slone has helped direct our investor relations and public affairs functions since joining us in 1997.

David N. Warnecke, 50, is our Vice President — Marketing and Trading and is President of our Arch Coal Sales Company, Inc. subsidiary. Previously, Mr. Warnecke served as President of Arch Transportation Company and served as Executive Vice President of Arch Coal Sales Company, Inc. until June 1, 2005 when he was appointed President.

Available Information

We file annual, quarterly and current reports, and amendments to those reports, proxy statements and other information with the Securities and Exchange Commission. You may access and read our filings without charge through the SEC's website, at sec.gov. You may also read and copy any document we file at the SEC's public reference room located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

We also make the documents listed above available through our website, archcoal.com, as soon as practicable after we file or furnish them with the SEC. You may also request copies of the documents, at no cost, by telephone at (314) 994-2700 or by mail at Arch Coal, Inc., One CityPlace Drive, Suite 300, St. Louis, Missouri, Attention: Vice President — Investor Relations. The information on our website is not part of this Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS.

Our business inherently involves certain risks and uncertainties. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations. Should one or more of any of these risks materialize, our business, financial condition or results of operations could be materially adversely affected.

Risks Related to Our Business

A substantial or extended decline in coal prices could reduce our revenue and the value of our coal reserves.

Our results of operations are substantially dependent upon the prices we receive for our coal. The prices we receive for our coal depend upon factors beyond our control, including:

- the supply of and demand for domestic and foreign coal;
- the demand for electricity in the United States;
- the capacity and cost of transportation facilities;
- domestic and foreign governmental regulations and taxes;
- air emission standards for domestic and foreign coal-fired power plants;
- regulatory, administrative and judicial decisions that affect the coal mining industry;
- the price and availability of alternative fuels, including the effects of technological developments;
- the effect of worldwide energy conservation measures; and
- the supply of and demand for metallurgical coal.

Any one or more of the foregoing factors could adversely affect the sale prices we may be able to obtain for our coal. Declines in the prices we receive for our coal could adversely affect our operating results and our revenue.

Any change in coal demand by U.S. electric power generators that results in a decrease in the use of coal could result in lower prices for our coal, which would reduce our revenue and adversely impact our earnings and the value of our coal reserves.

Demand for our coal and the prices that we may obtain for our coal are closely linked to coal consumption patterns of the domestic electric generation industry, which has accounted for approximately 92% of domestic coal consumption in recent years according to the EIA. The amount of coal consumed for U.S. electric power generation is influenced by factors beyond our control, including:

- the overall demand for electricity, which is significantly dependent upon general economic conditions and summer and winter temperatures in the United States;
- environmental and government regulation;
- technological developments; and
- the location, availability, quality and price of competing sources of coal, alternative fuels such as natural gas, oil and nuclear and alternative energy sources such as hydroelectric power.

Demand for our low sulfur coal and the prices that we will be able to obtain for it will also be affected by the price and availability of high sulfur coal, which can be marketed in tandem with emissions allowances in order to meet Clean Air Act requirements.

In addition, the requirements of the Clean Air Act may result in more electric power generations shifting from coal to natural gas-fired power plans. Any reduction in the amount of coal consumed by domestic electric power generators could reduce the price of steam coal that we produce, thereby reducing our revenue and adversely affecting our earnings and the value of our coal reserves.

Our coal mining production is subject to conditions and events beyond our control, which could result in higher operating expenses or decreased production and adversely affect our operating results.

Our coal mining operations are conducted in underground mines and at surface mines. The level of our production at these mines is subject to operating conditions and events beyond our control that could disrupt operations, affect production and the costs of mining at particular mines for varying lengths of time and have a significant impact on our operating results. Adverse operating conditions and events that we may experience include:

- unexpected variations in geological conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposit;
- mining and processing equipment failures and unexpected maintenance problems;
- interruptions due to transportation delays;
- unexpected delays and difficulties in acquiring, maintaining or renewing necessary permits or mining or surface rights;
- unavailability of mining equipment and supplies and increases in the price of mining equipment and supplies;
- shortage of qualified labor and a significant rise in labor costs;
- fluctuations in the cost of industrial supplies, including steel-based supplies, natural gas, diesel fuel and oil;
- adverse weather and natural disasters, such as heavy rains and flooding;
- unexpected or accidental surface subsidence from underground mining;
- accidental mine water discharges, fires, explosions or similar mining accidents;
- regulatory issues involving the plugging of and mining through oil and gas wells that penetrate the coal seams we mine; and
- the cost of surety bonds and the collateral required for our mining complexes is increasing and the surety bonds are becoming more difficult to obtain.

If any of these conditions or events occur in the future at any of our mining complexes, particularly our Black Thunder mine, our cost of mining and any delay or halt of production either permanently or for varying lengths of time could adversely affect our operating results. In addition, if we do not have insurance covering certain of these conditions or events or if the insurance coverage we have is limited or excludes certain of these conditions or events, then we may not be able to recover any of the losses we may incur as a result of such conditions or events, some of which may be substantial.

Increases in the price of steel and petroleum products and a shortage of tires used in our mining operations could significantly affect our operating profitability.

Our coal mining operations use significant amounts of steel, diesel fuel and tires. The price of scrap steel, which is used in making roof bolts and required by the room and pillar method of mining, has risen significantly in recent months. During 2005, the costs of diesel fuel, explosives and coal trucking increased as a direct result of supply chain problems related to Hurricane Katrina’s devastation in Mississippi and Louisiana and Hurricane Rita’s destruction in Texas and Louisiana. There may be other acts of nature that could also increase the costs of raw materials. We have also recently experienced a shortage in rubber tires, which are used on the trucks and heavy machinery with which we operate our mines. If the price of steel, petroleum products or other materials remains high or continues to increase and if tires continue to remain in short supply, our operational expenses will remain high or increase and our production could be affected, which could have a significant negative impact on our profitability.

There is a shortage of skilled coal mining workers, and as a result we are facing significantly higher labor costs as well as competition for workers from other coal producers.

Efficient coal mining using modern techniques and equipment requires skilled workers, preferably with at least one year of experience and proficiency in multiple mining tasks. Increased demand for coal and the increase in the market price for such coal in recent years has caused a resurgence of mining activity. Consequently, there has been a significant tightening of the labor supply and an increase in the turnover of the labor force as coal producers compete with each other for skilled personnel. In recent years, a shortage of trained coal miners has caused us to operate certain units without full staff, which has decreased our productivity and increased our costs. We are currently experiencing increasing labor costs, especially with regard to state certified electricians who are in short supply. We employ certain drug testing programs and take appropriate corrective actions that include terminating or suspending workers caught abusing drugs. This causes us to lose otherwise skilled workers and puts further pressure on what is already a tight labor supply. In addition, because of the shortage of experienced miners, we have hired novice miners, who are required to be accompanied by experienced workers as a safety precaution. These measures adversely affect the productivity of our workers as well as the operating efficiency of our mining complexes. If the shortage of experienced labor continues or worsens and if our labor costs continue to rise, it could have an adverse impact on our labor productivity and costs and our ability to expand production.

Disruption in supplies of coal produced by our contract mine operators could temporarily impair our ability to fill customers’ orders or increase our costs.

We utilize independent contractors to operate certain of our mining complexes, including select operations at our Coal-Mac, Cumberland River and Mingo Logan mining complexes. Operational difficulties at contractor-operated mines, changes in demand for contract miners from other coal producers and other factors beyond our control could affect the availability, pricing, and quality of coal produced for us by contractors.

Disruption in our supply of contractor-produced coal could temporarily impair our ability to fill our customers' orders or require us to pay higher prices in order to obtain the required coal from other sources. Any increase in the prices we pay for contractor-produced coal could increase our costs and, therefore, reduce our profitability.

We face numerous uncertainties in estimating our economically recoverable coal reserves, and inaccuracies in our estimates could result in decreased profitability from lower than expected revenue or higher than expected costs.

We base our forecasts of future performance on, among other things, estimates of our recoverable coal reserves. We base our estimates of reserve information on engineering, economic and geological data assembled and analyzed by internal and third party engineers and reviewed periodically by third party consultants. There are numerous uncertainties inherent in estimating quantities and qualities of, and costs to mine, recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves and net cash flows necessarily depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions include:

- unexpected geological and mining conditions which may not be fully identified by available exploration data or drill hole density and may differ from our experiences in areas we currently mine;
- future coal prices, operating costs, capital expenditures, severance and excise taxes, royalties and development and reclamation costs;
- future mining technology improvements; and
- the assumed effects of regulation by governmental agencies.

For these reasons, estimates of the economically recoverable quantities and qualities attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of net cash flows expected from particular reserves prepared by different engineers or by the same engineers at different times may vary substantially. Actual coal tonnage recovered from identified reserve areas or properties and revenue and expenditure with respect to our reserves may vary materially from estimates. As a result, these estimates may not accurately reflect our actual reserves. Any inaccuracy in our estimates related to our reserves could result in lower than expected revenue, higher than expected costs or decreased profitability.

Defects in title or loss of any leasehold interests in our properties could limit our ability to mine these properties or result in significant unanticipated costs.

We conduct a significant part of our mining operations on properties that we lease. A title defect or the loss of any lease could adversely affect our ability to mine the associated reserves. Because title to most of our leased properties and mineral rights is not usually verified until we make a commitment to develop a property, which may not occur until after we have obtained necessary permits and completed exploration of the property, our right to mine some of our reserves has in the past, and may again in the future, be adversely affected if defects in title or boundaries exist. In order to obtain leases or mining contracts to conduct our mining operations on property where these defects exist, we have had to, and may in the future have to, incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases or mining contracts for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease. Some leases have minimum production requirements. Failure to meet those requirements could result in losses of prepaid royalties and, in some rare cases, could result in a loss of the lease itself.

Fluctuations in transportation costs and the availability and reliability of transportation facilities could affect the demand for our coal or temporarily impair our ability to supply coal to our customers.

We depend upon barge, rail, truck and belt transportation systems to deliver coal to our customers. Disruption of these transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could temporarily impair our ability to supply coal to our customers, resulting in decreased shipments. Decreased performance levels over longer periods of time could cause our customers to look to other sources for their coal needs, negatively affecting our revenue and profitability. We have no long-term contracts with transportation providers to ensure consistent and reliable service. In addition, increases in transportation costs, including increases resulting from fluctuations in the price of gasoline and diesel fuel, could make coal a less competitive source of energy when compared to alternative fuels such as natural gas or could make our coal production less competitive than coal produced in other regions of the United States or abroad. If there are disruptions of the transportation services provided by the railroad companies we use, or if rail transport costs rise significantly and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

Acquisitions that we may undertake would involve a number of inherent risks, any of which could cause us not to realize the benefits anticipated to result.

We continually seek to expand our operations and coal reserves through acquisitions of businesses and assets, including leases of coal reserves. Acquisitions involve various inherent risks, such as:

- uncertainties in assessing the value, strengths and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental liabilities) of, acquisition or other transaction candidates;
- the potential loss of key customers, management and employees of an acquired business;
- the ability to achieve identified operating and financial synergies anticipated to result from an acquisition or other transaction;
- problems that could arise from the integration of the acquired business; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying the acquisition or other transaction rationale.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from the acquisition of businesses or assets or could result in unexpected liabilities associated with these acquisition candidates.

Our business will be adversely affected if we are unable to develop or acquire additional coal reserves that are economically recoverable.

We control substantial undeveloped reserves and have not identified the equipment or workforce that will be employed to mine these reserves. Permits have been obtained for some of these undeveloped reserves. We expect to obtain the required remaining permits by the time we commence mining these reserves, but we may be unable to do so at all or within the necessary time period. Some of the required permits are becoming increasingly more difficult and expensive to obtain and the application review processes are taking longer to complete and becoming increasingly subject to challenge.

We may not be able to mine all our reserves as profitably as we do at our current operations. Our planned development projects and acquisition activities may not result in significant additional reserves, and we may not have continuing success developing new mines or expanding existing mines beyond our existing reserve base. Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers.

Because the amount of coal in our reserves decline as we mine our coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. Replacement reserves may not be available when required or, if available, may not be available at commercially attractive prices or be capable of being mined at comparable costs. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

Our profitability may be adversely affected by our commitments under long-term coal supply contracts and changes in purchasing patterns in the coal industry may make it difficult for us to extend existing contracts or to enter into long-term supply contracts.

We sell a substantial portion of our coal under long-term coal supply agreements, which we define as contracts with a term greater than 12 months. The prices for coal shipped under these contracts is fixed for the initial year of the contract and may be subject to certain adjustments in later years. As a result, the prices for coal shipped under these contracts may be below the current market price for similar-type coal at any given time, depending on the timeframe of the contract execution or initiation. For the year ended December 31, 2005, we sold approximately 70% of the total tons sold pursuant to long-term coal supply agreements. As a consequence of the substantial volume of our sales that are subject to these long-term agreements, we have less coal available with which to capitalize on higher coal prices if and when they arise. In addition, in some cases, our ability to realize the higher prices that may be available in the open market may be restricted when customers elect to purchase higher volumes under some contracts.

When our current contracts with customers expire or are otherwise renegotiated, our customers may decide not to extend or enter into new long-term contracts or, in the absence of long-term contracts, our customers may decide to purchase fewer tons of coal than in the past or on different terms, including under different pricing terms. Furthermore, uncertainty caused by laws and regulations affecting electric utilities, including the Clean Air Act, could deter our customers from entering into long-term coal supply agreements. To the degree that we operate outside of long-term contracts, our revenues are subject to pricing in the coal open market, which can be significantly more volatile than the pricing structure negotiated through a long-term coal supply agreement. This volatility could adversely affect the profitability of our operations if open market pricing for coal becomes unfavorable. For additional information relating to these contracts, you should see “Business — Coal Supply Contracts” under Item 1.

The loss of, or significant reduction in, purchases by our largest customers could adversely affect our revenues.

For the year ended December 31, 2005, we derived approximately 29% of our total coal revenues from sales to our three largest customers, Tennessee Valley Authority, American Electric Power and Progress Fuels, and approximately 53% of our total coal revenues from sales to our ten largest customers. At December 31, 2005, we had coal supply agreements with those ten customers that expire at various times from 2006 to 2017. We intend to discuss the extension of existing agreements or entering into new long-term agreements with those and other customers, but the negotiations may not be successful, and those customers may not continue to purchase coal from us under long-term coal supply agreements, or at all. If any of those customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our revenues and profitability could suffer materially.

Certain provisions in our long-term supply agreements may provide limited protection during adverse economic conditions or may result in economic penalties upon the failure to meet specifications.

Coal supply agreements typically contain force majeure provisions allowing temporary suspension of performance by us or our customers during the duration of specified events beyond the control of the affected party. Most of our coal supply agreements also contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as heat value, sulfur content, ash content, hardness and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, purchasing replacement coal in the higher priced open market, the rejection of deliveries or, in the extreme, termination of the contracts. Consequently, due to the risks mentioned above with respect to long-term supply agreements, we may not achieve the revenue or profit we expect to achieve from these sales commitments.

We have a significant amount of debt relative to our total capitalization, which limits our flexibility and imposes restrictions on us, and a downturn in economic or industry conditions may materially affect our ability to meet our future financial commitments and liquidity needs.

As of December 31, 2005, we had consolidated indebtedness of approximately $982.4 million, representing approximately 45% of our total capitalization. We also have significant lease and royalty obligations. Our ability to satisfy our debt, lease and royalty obligations, and our ability to refinance our indebtedness, will depend upon our future operating performance, which will be affected by prevailing economic conditions in the markets that we serve and financial, business and other factors, many of which are beyond our control. We may be unable to generate sufficient cash flow from operations and future borrowings or other financing may be unavailable in an amount sufficient to enable us to fund our future financial obligations or our other liquidity needs.

The amount and terms of our debt could have material consequences to our business, including, but not limited to:

- making it more difficult for us to satisfy our debt covenants and debt service, lease payment and other obligations;
- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to obtain additional financing to fund future acquisitions, working capital, capital expenditures or other general operating requirements;
- reducing the availability of cash flow from operations to fund acquisitions, working capital, capital expenditures or other general operating purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete; and
- placing us at a competitive disadvantage when compared to competitors with less relative amounts of debt.

Despite these significant levels of indebtedness, we may incur additional indebtedness in the future, which would heighten the risks described above.

If our assumptions regarding our likely future expenses related to benefits for non-active employees are incorrect, then expenditures for these benefits could be materially higher than we have predicted.

We are subject to long-term liabilities under a variety of benefit plans and other arrangements with current and former employees. These obligations have been estimated based on actuarial assumptions, including:

- actuarial estimates;
- assumed discount rates;
- estimates of mine lives;
- expected returns on pension plan assets; and
- changes in health care costs.

If our assumptions relating to these benefits change in the future or are incorrect, we may be required to record additional expenses, which would reduce our profitability. In addition, future regulatory and accounting changes relating to these benefits could result in increased obligations or additional costs, which could also have a material adverse affect on our financial results. You should see Note 12 — Employee Benefit Plans to our consolidated financial statements included in our 2005 Annual Report to Stockholders for more information about these assumptions.

Increased consolidation and competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.

During the last several years, the U.S. coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. According to the NMA, in 1994, the top ten coal producers accounted for approximately 45% of total domestic coal production. By 2004, however, the top ten coal producers' share had increased to approximately 69% of total domestic coal production, according to the NMA. Consequently, some of our competitors in the domestic coal industry are major coal producers who have greater financial resources than we do. The intense competition among coal producers may impact our ability to retain or attract customers and may, therefore, adversely affect our future revenue and profitability. Recent increases in coal prices could encourage the development of expanded coal producing capacity in the United States. Any resulting overcapacity from existing or new competitors could reduce coal prices and, therefore, our revenue.

We may be unable to comply with restrictions imposed by our credit facilities and other financing arrangements which could result in a default under these agreements.

The agreements governing our outstanding debt and our accounts receivable securitization program impose a number of restrictions on us. For example, the terms of our credit facilities, leases and other financing arrangements contain financial and other covenants that create limitations on our ability to, among other things, borrow the full amount under our credit facilities, effect acquisitions or dispositions and incur additional debt, and require us to, among other things, maintain various financial ratios and comply with various other financial covenants. Our ability to comply with these restrictions may be affected by events beyond our control and, as a result, we may be unable to comply with these restrictions. A failure to comply with these restrictions could adversely affect our ability to borrow under our credit facilities or result in an event of default under these agreements. In the event of a default, our lenders and the counterparties to our other financing arrangements could terminate their commitments to us and declare all amounts borrowed, together with accrued interest and fees, immediately due and payable. If this were to occur, we might not be able to pay these amounts, or we might be forced to seek an amendment to our financing arrangements which could make the terms of these arrangements more onerous for us.

Changes in our credit ratings could adversely affect our costs and expenses.

On October 15, 2004, Moody's downgraded our credit ratings, including the ratings on our outstanding senior notes, to Ba3 with a stable outlook. Any downgrade in our credit ratings could adversely affect our ability to borrow and result in more restrictive borrowing terms, including increased borrowing costs, more restrictive covenants and the extension of less open credit. This in turn could affect our internal cost of capital estimates and therefore operational decisions.

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease coal.

Federal and state laws require us to obtain surety bonds to secure performance or payment of certain long-term obligations such as mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other obligations. These bonds are typically re-priced annually but are non-cancellable by the surety.

Surety bond issuers and holders may increase premiums associated with the bonds or impose other less favorable terms upon those renewals. The ability of surety bond issuers and holders to demand additional collateral or other less favorable terms has increased as the number of companies willing to issue these bonds has decreased over time. Our failure to maintain, or our inability to acquire, surety bonds that are required by state and federal law would affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease coal. That failure could result from a variety of factors including:

- lack of availability, higher expenses or unfavorable market terms of new bonds;
- restrictions on availability of collateral for current and future third party surety bond issuers under the terms of our credit facility; and
- insufficient borrowing capacity under our revolving credit facility or our receivable securitization facility for additional letters of credit.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our business, financial condition and results of operations.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our business, financial condition, and results of operations. Our business is affected by general economic conditions, fluctuations in consumer confidence and spending, and market liquidity, which can decline as a result of numerous factors outside of our control, such as terrorist attacks and acts of war. Future terrorist attacks against U.S. targets, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions affecting our customers may materially adversely affect our operations and those of our customers. As a result, there could be delays or losses in transportation and deliveries of coal to our customers, decreased sales of our coal and extension of time for payment of accounts receivable from our customers. In addition, disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Environmental and Other Regulation

Federal and state governments extensively regulate our mining operations, which imposes significant costs on us, and future regulations could increase those costs or limit our ability to produce and sell coal.

The coal mining industry is subject to increasingly strict regulation by federal, state and local authorities with respect to matters such as:

- the discharge of materials into the environment;
- employee health and safety;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- management of materials generated by mining operations;
- surface subsidence from underground mining;

- water pollution;
- statutorily mandated benefits for current and retired coal miners;
- air quality standards;
- protection of wetlands;
- endangered plant and wildlife protection;
- limitations on land use;
- storage and disposal of petroleum products and substances that are regarded as hazardous under applicable laws; and
- management of electrical equipment containing PCBs.

The costs, liabilities and requirements associated with these regulations may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. Failure to comply with these regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. We may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. If we incur significant costs and liabilities, our business, financial condition and results of operations could be adversely affected. You should see “Business — Environmental Matters” under Item 1.

The possibility exists that new legislation and/or regulations and orders may be adopted that may materially adversely affect our mining operations, our cost structure and/or our customers’ ability to use coal. New legislation or administrative regulations (or new judicial interpretations or administrative enforcement of existing laws and regulations), including proposals related to the protection of the environment that would further regulate and tax the coal industry, may also require us or our customers to change operations significantly or incur increased costs. Such regulations, if enacted in the future, could have a material adverse effect on our business, financial condition and results of operations.

We may be unable to obtain and renew permits necessary for our operations, which would reduce our production, cash flow and profitability.

Mining companies must obtain numerous permits that strictly regulate environmental and health and safety matters in connection with coal mining including permits issued by various federal and state agencies and regulatory bodies. We believe that we have obtained the necessary permits to mine our developed reserves at our mining complexes. However, as we commence mining our undeveloped reserves, we will need to apply for and obtain the required permits. The permitting rules are complex and change frequently, making our ability to comply with the applicable requirements more difficult or even impossible, thereby precluding continuing or future mining operations. Private individuals and the public at large have certain rights to comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need for our mining operations may not be issued, or, if issued, may not be issued in a timely fashion, or may involve requirements that may be changed or interpreted in a manner which restricts our ability to conduct our mining operations or to do so profitably. An inability to conduct our mining operations pursuant to applicable permits would reduce our production, cash flow and profitability.

The Clean Air Act affects us and our customers, and could increase the cost of coal production and/or reduce the demand for coal as a fuel source and thereby cause our sales and profitability to decline.

The Clean Air Act regulates coal mining operations both directly and indirectly. Direct impacts on coal mining and processing operations may occur through Clean Air Act permitting requirements and/or emission control requirements, including requirements relating to particulate matter. The Clean Air Act indirectly affects coal mining operations by extensively regulating the air emissions of sulfur dioxide, nitrogen oxide, mercury and other compounds emitted by coal-fired electricity generating plants. Clean Air Act requirements that may directly or indirectly affect our operations or those of our electric utility customer base, and which could cause them to reduce their coal usage, include:

- reduction of sulfur dioxide emissions imposed by Title IV of the Clean Air Act;
- reduction of sulfur dioxide, nitrogen oxide and ozone emissions under EPA National Ambient Air Quality Standards;
- reduction of nitrogen oxide emissions under the NOx SIP Call program;
- reduction of nitrous oxide, sulfur dioxide, and mercury emissions by power plants through “cap-and-trade” programs under the Clear Skies Initiative;
- reduction of sulfur dioxide and nitrogen oxide emissions under the Clean Air Interstate Rule;
- reduction of and permanent cap on mercury emissions from coal-fired power plants under the Utility Mercury Reductions Rule;
- potential reduction of carbon dioxide emissions that could result from ongoing state lawsuits against the EPA; and
- reduction requirements for regional haze around national parks and national wilderness areas.

The potential negative effects of these emissions and other requirements on our business include:

- reduction in demand for our coal by electric utilities, our largest customers, due to increased compliance requirements, which could impose significant capital expenditure and costs on coal-fired electricity generation;
- reduction in demand for our coal due to decisions by our customers to replace outdated coal plants with, or to construct new plants using, alternative fuel technologies, due to increased capital expenditure, cost or permitting restrictions; and
- increased costs to us of coal mining and/or processing due to permitting requirements and/or emission control requirements relating to particulate matter.

Any resulting decrease in the demand for our coal will adversely affect our business and our results of operations.

We have significant reclamation and mine closure obligations. If the assumptions underlying our accruals are materially inaccurate, we could be required to expend greater amounts than anticipated.

SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Estimates of our total reclamation and mine-closing liabilities are based upon permit requirements and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by our management and engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. Statement of Financial Accounting Standard No. 143, “Accounting for Asset Retirement Obligations,” requires that retirement obligations be recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows. In estimating future cash flows, we considered the estimated current cost of reclamation and applied inflation rates and a third-party profit, as necessary. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. Our resulting liability could change significantly if actual costs differ from our assumptions.

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share. We are not subject to material claims arising out of contamination at our facilities or other locations, but may incur such liabilities in the future.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mining complexes. Such areas and impoundments are subject to extensive regulation. Slurry impoundments have been known to fail, releasing large volumes of coal slurry into the surrounding environment. Structural failure of an impoundment can result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental contamination and associated liability, as well as for fines and penalties.

Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals; a condition referred to as “acid mine drainage,” which we refer to as AMD. The treating of AMD can be costly. Although we do not currently face material costs associated with AMD, it is possible that we could incur significant costs in the future.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could materially and adversely affect us.

Judicial rulings that restrict how we may dispose of mining wastes could significantly increase our operating costs, discourage customers from purchasing our coal, and materially harm our financial condition and operating results.

To dispose of mining overburden generated by our surface mining operations, we often need to obtain permits to construct and operate valley fills and surface impoundments. Some of these permits are "nationwide" permits (as opposed to individual permits) issued by the Army Corps of Engineers for dredging and filling in streams and wetlands. Lawsuits challenging the Army Corps of Engineers' authority to issue Nationwide Permit 21 have been instituted by environmental groups. In 2004, a federal court issued an order enjoining the Army Corps of Engineers from issuing further Nationwide 21 permits in the Southern District of West Virginia, although such ruling has not affected the ability of mining operations to seek and apply for individual permits for mining activities. The decision was appealed and has subsequently been remanded to the district court for further consideration. We cannot predict the final outcomes of this lawsuit. If mining methods at issue are limited or prohibited, it could significantly increase our operational costs, make it more difficult to economically recover a significant portion of our reserves and lead to a material adverse effect on our financial condition and results of operation. We may not be able to increase the price we charge for coal to cover higher production costs without reducing customer demand for our coal. You should see the section entitled "Contingencies" appearing in "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report to Stockholders for more information about the litigation described above.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

As of December 31, 2005, we owned or controlled primarily through long-term leases approximately 156,000 acres of coal land in West Virginia, 99,000 acres of coal land in Wyoming, 82,000 acres of coal land in Illinois, 63,000 acres of coal land in Utah, 54,000 acres of coal land in Kentucky, 22,000 acres of coal land in New Mexico and 17,000 acres of coal land in Colorado. In addition, we also owned or controlled through long-term leases smaller parcels of property in Alabama, Indiana, Montana and Texas. We lease approximately 115,000 acres of our coal land from the federal government and approximately 28,000 acres of our coal land from various state governments. These governmental leases have terms expiring between 2007 and 2010 and are subject to readjustment and/or extension and to earlier termination for failure to meeting diligent development requirements. Our Pardee, Levan, Sufco, Cardinal, Holden 22, Mingo Logan, Ragland, Medicine Bow and Seminoe II preparation plants or loadout facilities are located on properties held under leases which expire at varying dates over the next thirty years. Most of the leases contain options to renew. Our remaining preparation plants and loadout facilities are located on property owned by us or for which we have a special use permit.

Our executive headquarters occupy approximately 93,000 square feet of leased space at One CityPlace Drive, in St. Louis, Missouri. Our subsidiaries currently own or lease the equipment utilized in their mining operations. You should see "Item 1. Business" for more information about our mining operations, mining complexes and transportation facilities.

Our Reserves

We estimate that we owned or controlled approximately 3.1 billion tons of proven and probable recoverable reserves at December 31, 2005. Recoverable reserves include only saleable coal and do not include coal which would remain unextracted, such as for support pillars, and processing losses, such as washery losses. Reserve estimates are prepared by our engineers and geologists and reviewed and updated periodically. Total recoverable reserve estimates and reserves dedicated to mines and complexes change from time to time to reflect mining activities, analysis of new engineering and geological data, changes in reserve holdings and other factors.

The following tables present by state our estimated assigned and unassigned recoverable coal reserves at December 31, 2005:

Total Assigned Reserves
(tonnage in millions)

	Total Assigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus)			As Received Btu per lb.(1)	Reserve Control		Mining Method		Past Reserve Estimates	
				<1.2	1.2-2.5	>2.5		Leased	Owned	Surface	Underground	2003	2004
Wyoming	1,748	1,705	43	1,697	51	—	8,814	1,746	2	1,748	—	1,025	1,840
Central App	243	190	53	72	171	—	12,937	221	22	79	164	441	409
Illinois	13	12	1	—	—	13	10,725	—	13	13	—	—	—
Utah	108	60	48	108	—	—	11,653	107	1	—	108	116	112
Colorado	74	56	18	73	1	—	11,866	72	2	—	74	85	80
Total	2,186	2,023	163	1,950	223	13	9,526	2,146	40	1,840	346	1,667	2,441

(1) As received btu per lb. includes the weight of moisture in the coal on an as sold basis.

Total Unassigned Reserves
(tonnage in millions)

	Total Unassigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus)			As Received Btu per lb.(1)	Reserve Control		Mining Method	
				<1.2	1.2-2.5	>2.5		Leased	Owned	Surface	Underground
Wyoming	387	273	114	338	49	—	9,671	282	105	213	174
Central App	166	117	49	78	45	43	12,604	105	61	48	118
Illinois	244	175	69	—	—	244	11,356	36	208	2	242
Utah	37	15	22	32	5	—	11,177	37	—	—	37
Colorado	56	45	11	55	1	—	11,498	55	1	—	56
Total	890	625	265	503	100	287	10,857	515	375	263	627

(2) As received btu per lb. includes the weight of moisture in the coal on an as sold basis.

As of December 31, 2005, approximately 13.5% of our coal reserves were held in fee, with the balance controlled by leases, most of which do not expire until the exhaustion of mineable and merchantable coal. Other leases have primary terms expiring in various years ranging from 2006 to 2020, and most contain options to renew for stated periods. Under current mining plans, substantially all reported leased reserves will be mined out within the period of existing leases or within the time period of assured lease renewals. Royalties are paid to lessors either as a fixed price per ton or as a percentage of the gross sales price of the mined coal. The majority of the significant leases are on a percentage royalty basis. In some cases, a lease bonus (prepaid royalty) is required, payable either at the time of execution of the lease or in annual installments. In most cases, the prepaid royalty amount is applied to reduce future production royalties.

Federal and state legislation controlling air pollution affects the demand for certain types of coal by limiting the amount of sulfur dioxide which may be emitted as a result of fuel combustion and encourages a greater demand for low sulfur coal. All of our identified coal reserves have been subject to preliminary coal seam analysis to test sulfur content. Of these reserves, approximately 79.7% consist of compliance coal, or coal which emits 1.2 pounds or less of sulfur dioxide per million Btu upon combustion, while an additional 7.0% could be sold as low-sulfur coal. The balance is classified as high-sulfur coal. Some of our low-sulfur coal can be marketed as compliance coal when blended with other compliance coal. Accordingly, most of our reserves are primarily suitable for the domestic steam coal markets. However, a substantial portion of the low-sulfur and compliance coal reserves at the Mingo Logan, Cumberland River and Lone Mountain operations may also be used as a high-volatile, low-sulfur, metallurgical coal.

The carrying cost of our coal reserves at December 31, 2005 was $1.07 billion, consisting of $108.4 million of prepaid royalties and the $957.8 million net book value of coal lands and mineral rights.

Title to coal properties held by lessors or grantors to us and our subsidiaries and the boundaries of properties are normally verified at the time of leasing or acquisition. However, in cases involving less significant properties and consistent with industry practices, title and boundaries are not completely verified until such time as our independent operating subsidiaries prepare to mine such reserves. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine such reserves could be adversely affected.

From time to time, lessors or sublessors of land leased by our subsidiaries have sought to terminate such leases on the basis that such subsidiaries have failed to comply with the financial terms of the leases or that the mining and related operations conducted by such subsidiaries are not authorized by the leases. Some of these allegations relate to leases upon which we conduct operations material to our consolidated financial position, results of operations and liquidity, but we do not believe any pending claims by such lessors or sublessors have merit or will result in the termination of any material lease or sublease. You should see “Contingencies” appearing in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” contained in our 2005 Annual Report to Stockholders for more information about these claims.

We leased approximately 21,000 acres of property to other coal operators in 2005. We received royalty income of $7.1 million in 2005 from the mining of approximately 3.0 million tons, $4.0 million in 2004 from the mining of approximately 2.9 million tons and $1.7 million in 2003 from the mining of approximately 1.3 million tons on those properties. We have included reserves at properties leased by us to other coal operators in the reserve figures set forth in this report.

We must obtain permits from applicable state regulatory authorities before we begin to mine particular reserves. Applications for permits require extensive engineering and data analysis and presentation, and must address a variety of environmental, health and safety matters associated with a proposed mining operation. These matters include the manner and sequencing of coal extraction, the storage, use and disposal of waste and other substances and other impacts on the environment, the construction of overburden fills and water containment areas, and reclamation of the area after coal extraction. We are required to post bonds to secure performance under our permits. As is typical in the coal industry, we strive to obtain mining permits within a time frame that allows us to mine reserves as planned on an uninterrupted basis. We generally begin preparing applications for permits for areas that we intend to mine up to three years in advance of their expected issuance date. Regulatory authorities have considerable discretion in the timing of permit issuance and the public has rights to comment on and otherwise engage in the permitting process, including through intervention in the courts.

Our reported coal reserves are those that could be economically and legally extracted or produced at the time of their determination. In determining whether our reserves meet this standard, we take into account, among other things, our potential inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in costs required to be incurred to meet regulatory requirements and obtaining mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices. We have obtained, or we have a high probability of obtaining, all required permits or government approvals with respect to our reserves. Except as described elsewhere in this document with respect to permits to conduct mining operations involving valley fills, which has been taken into account in determining our reserves, we are not currently aware of matters which would significantly hinder our ability to obtain future mining permits or governmental approvals with respect to our reserves.

We periodically engage third parties to review our reserve estimates. The most recent third party review of our reserve estimates was conducted by Weir International Mining Consultants in February 2006.

ITEM 3. LEGAL PROCEEDINGS.

There is hereby incorporated by reference into this Annual Report on Form 10-K the information under the caption “Contingencies” appearing in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” contained in our 2005 Annual Report to Stockholders.

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

There were no matters submitted to a vote of security holders through the solicitation of proxies or otherwise during the fourth quarter of 2005.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

We incorporate by reference the information under the caption “Corporate Governance and Stockholder Information” contained in our 2005 Annual Report to Stockholders.

On December 30, 2005, we issued an aggregate of 6,654,119 shares of our common stock pursuant to Section 3(a)(9) of the Securities Act of 1933 to certain holders of our preferred stock who elected to convert their preferred stock to shares of our common stock pursuant to a conversion offer that we commenced on December 1, 2005. We had previously registered shares of common stock that could be issued upon conversion of all of the preferred stock we originally issued in January 2003. As part of the conversion offer, we agreed to pay holders of our preferred stock who elected to convert their preferred stock a premium, payable in shares of our common stock, valued at $3.50. As a result of the conversion offer, we issued an aggregate of 6,534,517 shares of common stock pursuant to the conversion terms of the preferred stock and an aggregate premium of 119,602 shares of common stock. We estimate that the premium we paid was less than the net present value of the remaining preferred stock dividends to be paid through the date on which the preferred stock becomes callable by us.

The following table summarizes information about shares of our common stock that we purchased during the fourth quarter of 2005.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased As Part of our Share Repurchase Program(1)	Approximate Dollar Value of Shares that May Yet be Purchased Under Our Share Repurchase Program
Oct. 1 - Oct. 31, 2005	—		—	
Nov. 1 - Nov. 30, 2005	—		—	
Dec. 1 - Dec. 31, 2005	—		—	
Total	—		—	$ 426,877,820(2)

(1) In September 2001, our board of directors authorized a share repurchase program for the purchase of up to 6,000,000 shares of our common stock. As of December 31, 2005, 357,200 shares have been purchased under this program.

(2) Calculated using 5,642,800 shares of common stock which may yet be purchased under our share repurchase program and $75.65, the closing price of our common stock as reported on the New York Stock Exchange on March 1, 2006.

ITEM 6. SELECTED FINANCIAL DATA.

We incorporate by reference the information under the caption “Selected Financial Information” contained in our 2005 Annual Report to Stockholders.

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

We incorporate by reference the information under the caption “Management’s Discussion and Analysis of Financial Condition and Results of Operations” contained in our 2005 Annual Report to Stockholders.

The following table sets forth our ratios of earnings to combined fixed charges and preference dividends for the periods indicated:

	Years Ended December 31, 2005				
	2005	2004	2003	2002	2001
Ratio of earnings to combined fixed charges and preference dividends(1)	—	2.54x	—	—	1.04x

(1) Ratio of earnings to combined fixed charges and preference dividends is computed on a total enterprise basis including our consolidated subsidiaries, plus our share of significant affiliates accounted for on the

equity method that are 50% or greater owned or whose indebtedness has been directly or indirectly guaranteed by us. Earnings consist of income (loss) from continuing operations before income taxes and are adjusted to include fixed charges (excluding capitalized interest). Fixed charges consist of interest incurred on indebtedness, the portion of operating lease rentals deemed representative of the interest factor and the amortization of debt expense. Preference dividends are the amount of pre-tax earnings required to pay dividends on our outstanding preferred stock and Arch Western Resources, LLC's preferred membership interest. Combined fixed charges and preference dividends exceeded earnings by $0.8 million in 2005, $2.9 million in 2003 and $22.3 million in 2002.

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

We incorporate by reference the information under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our 2005 Annual Report to Stockholders.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Reference is made to Part IV, Item 15 of this Annual Report on Form 10-K for the information required by Item 8.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

We performed an evaluation under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2005. Based on that evaluation, our management, including our chief executive officer and chief financial officer, concluded that the disclosure controls and procedures were effective as of such date. There were no changes in internal control over financial reporting that occurred during our fiscal quarter ended December 31, 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We incorporate by reference management's annual report on internal control over financial reporting and the report of independent registered public accounting firm related thereto contained in our 2005 Annual Report to Stockholders.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

We incorporate by reference the information appearing in the sections entitled “Nominees for a Three-Year Term That Will Expire in 2009,” “Nominee for a Two-Year Term That Will Expire in 2008,” “Directors Whose Terms Will Expire in 2007,” “Directors Whose Term Will Expire in 2008” and “Section 16(a) Beneficial Ownership Reporting Compliance” in our proxy statement to be distributed to stockholders in connection with the 2006 annual meeting. You should also see the list of our executive officers and related information under “Executive Officers” in Part I, Item 1 of this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION.

We incorporate by reference the information appearing in the “Summary Compensation Table” and in the sections entitled “Compensation of Directors,” “Option Grants in Last Fiscal Year,” “Stock Option Exercises and Year-End Values,” “Long-Term Incentive Plans — Performance Contingent Phantom Stock Awards in Last Fiscal Year,” “Long-Term Incentive Plans — Performance Unit Awards in Last Fiscal Year,” “Pension Plans,” “Deferred Compensation Plan” and “Employment Agreements” in our proxy statement to be distributed to stockholders in connection with the 2006 annual meeting. We do not incorporate by reference any of the information appearing in the sections entitled “Report of the Personnel and Compensation Committee” or “Stock Price Performance Graph” in our proxy statement to be distributed to stockholders in connection with the 2006 annual meeting in reliance on Regulation S-K, Item 402(a)(8).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

We incorporate by reference the information appearing in the sections entitled “Ownership by Directors and Executive Officers” and “Ownership by Others” in our proxy statement to be distributed to stockholders in connection with the 2006 annual meeting.

Securities Authorized for Issuance Under Equity Compensation Plans

The Arch Coal, Inc. 1997 Stock Incentive Plan, which has been approved by our stockholders, is the sole plan under which we are authorized to issue shares of our common stock to employees. The following table shows the number of shares of common stock to be issued upon exercise of options outstanding at December 31, 2005, the weighted average exercise price of those options, and the number of shares of common stock remaining available for future issuance at December 31, 2005, excluding shares to be issued upon exercise of outstanding options. No warrants or rights had been issued under the plan as of December 31, 2005.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities to be Issued Upon Exercise)
Equity compensation plans approved by security holders	1,455,758	$ 20.81	2,650,101
Equity compensation plans not approved by security holders	—	—	—
Total	1,455,758	$ 20.81	2,650,101

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

None.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

We incorporate by reference the information appearing in the section “Independent Registered Public Accounting Firm” in our proxy statement to be distributed to stockholders in connection with the 2006 annual meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

We incorporate by reference the following consolidated financial statements and consolidated financial statement schedule of Arch Coal, Inc. and subsidiaries included in our 2005 Annual Report to Stockholders:

Consolidated Statements of Operations — Years Ended December 31, 2005, 2004 and 2003

Consolidated Balance Sheets — December 31, 2005 and 2004

Consolidated Statements of Stockholders’ Equity — Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Cash Flows — Years Ended December 31, 2005, 2004 and 2003

Notes to Consolidated Financial Statements

Schedule of Valuation and Qualifying Accounts.

All other schedules for which provision is made in the applicable accounting regulations of the Securities and Exchange Commission are not required under the related instructions or are inapplicable and, therefore, have been omitted.

Exhibits filed as part of this Annual Report on Form 10-K are as follows:

Exhibit	Description
2.1	Purchase and Sale Agreement, dated as of December 31, 2005, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 10.1 of the registrant's Current Report on Form 8-K filed on January 6, 2006).
2.2	Amendment No. 1 to the Purchase and Sale Agreement, dated as of February 7, 2006, by and between Arch Coal, Inc. and Magnum Coal Company.
3.1	Amended and Restated Certificate of Incorporation of Arch Coal, Inc. (incorporated by reference to Exhibit 3.1 of the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2000).
3.2	Restated and Amended Bylaws of Arch Coal, Inc. (incorporated by reference to Exhibit 3.2 of the registrant's Annual Report on Form 10-K for the year ended December 31, 2000).
4.1	Form of Rights Agreement, dated March 3, 2000 (incorporated by reference to Exhibit 1 to the registrant's Current Report on Form 8-A filed on March 9, 2000).
4.2	Description of Indenture pursuant to Shelf Registration Statement (incorporated herein by reference to the Registration Statement on Form S-3 (Registration No. 333-58738) filed by the registrant on April 11, 2001).
4.3	Certificate of Designations Establishing the Designations, Powers, Preferences, Rights, Qualifications, Limitations and Restrictions of the registrant's 5% Perpetual Cumulative Convertible Preferred Stock (incorporated herein by reference to Exhibit 3 to the Registration Statement on Form 8-A filed by the registrant on March 5, 2003).
4.4	Indenture, dated as of June 25, 2003, by and among Arch Western Finance, LLC, Arch Coal, Inc., Arch Western Resources, LLC, Arch of Wyoming, LLC, Mountain Coal Company, L.L.C., Thunder Basin Coal Company, L.L.C. and The Bank of New York, as trustee (incorporated herein by reference to Exhibit 4.1 to the Registration Statement on Form S-4 (Reg. No. 333-107569) filed by Arch Western Finance, LLC on August 1, 2003).
4.5	Credit Agreement, dated as of December 22, 2004, by and among Arch Coal, Inc., the Banks party thereto, PNC Bank, National Association, as administrative agent, Citicorp USA, Inc., JPMorgan Chase Bank, N.A., and Wachovia Bank, National Association, as co-syndication agents, and Fleet National Bank, as documentation agent (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by the registrant on December 28, 2004).
10.1	Amended and Restated Retention Agreement between Arch Coal, Inc. and Steven F. Leer, dated October 1, 2004 (incorporated by referenced to Exhibit 10.1 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004).
10.2	Form of Retention Agreement between Arch Coal, Inc. and each of its Executive Officers (other than its Chief Executive Officer) (incorporated by referenced to Exhibit 10.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004).

Exhibit	Description
10.3	Coal Lease Agreement dated as of March 31, 1992, among Hobet Mining, Inc. (successor by merger with Dal-Tex Coal Corporation) as lessee and UAC and Phoenix Coal Corporation, as lessors, and related guarantee (incorporated herein by reference to the Current Report on Form 8-K filed by Ashland Coal, Inc. on April 6, 1992).
10.4	Lease dated as of October 1, 1987, between Pocahontas Land Corporation and Mingo Logan Collieries Company whose name is now Mingo Logan Coal Company (incorporated herein by reference to Exhibit 10.3 to Amendment No. 1 to the Current Report on Form 8-K filed by Ashland Coal, Inc. on February 14, 1990).
10.5	Consent, Assignment of Lease and Guaranty dated January 24, 1990, among Pocahontas Land Corporation, Mingo Logan Coal Company, Mountain Gem Land, Inc. and Ashland Coal, Inc. (incorporated herein by reference to Exhibit 10.4 to Amendment No. 1 to the Current Report on Form 8-K filed by Ashland Coal, Inc. on February 14, 1990).
10.6	Federal Coal Lease dated as of June 24, 1993 between the United States Department of the Interior and Southern Utah Fuel Company (incorporated herein by reference to Exhibit 10.17 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.7	Federal Coal Lease between the United States Department of the Interior and Utah Fuel Company (incorporated herein by reference to Exhibit 10.18 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.8	Federal Coal Lease dated as of July 19, 1997 between the United States Department of the Interior and Canyon Fuel Company, LLC (incorporated herein by reference to Exhibit 10.19 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.9	Federal Coal Lease dated as of January 24, 1996 between the United States Department of the Interior and the Thunder Basin Coal Company (incorporated herein by reference to Exhibit 10.20 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.10	Federal Coal Lease Readjustment dated as of November 1, 1967 between the United States Department of the Interior and the Thunder Basin Coal Company (incorporated herein by reference to Exhibit 10.21 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.11	Federal Coal Lease effective as of May 1, 1995 between the United States Department of the Interior and Mountain Coal Company (incorporated herein by reference to Exhibit 10.22 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.12	Federal Coal Lease dated as of January 1, 1999 between the Department of the Interior and Ark Land Company (incorporated herein by reference to Exhibit 10.23 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.13	Federal Coal Lease dated as of October 1, 1999 between the United States Department of the Interior and Canyon Fuel Company, LLC (incorporated herein by reference to Exhibit 10 of the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 1999).

Exhibit	Description
10.14	Federal Coal Lease effective as of March 1, 2005 by and between the United States of America and Ark Land LT, Inc. covering the tract of land known as “Little Thunder” in Campbell County, Wyoming (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by the registrant on February 10, 2005).
10.15	Modified Coal Lease (WYW71692) executed January 1, 2003 by and between the United States of America, through the Bureau of Land Management, as lessor, and Triton Coal Company, LLC, as lessee, covering a tract of land known as “North Rochelle” in Campbell County, Wyoming (incorporated by reference to Exhibit 10.24 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2004).
10.16	Coal Lease (WYW71692) executed January 1, 1998 by and between the United States of America, through the Bureau of Land Management, as lessor, and Triton Coal Company, LLC, as lessee, covering a tract of land known as “North Roundup” in Campbell County, Wyoming (incorporated by reference to Exhibit 10.24 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2004).
10.17	Form of Indemnity Agreement between Arch Coal, Inc. and Indemnitee (as defined therein) (incorporated herein by reference to Exhibit 10.15 of the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.18*	Arch Coal, Inc. Incentive Compensation Plan For Executive Officers (incorporated herein by reference to Exhibit 99.1 of the Current Report on Form 8-K filed by the registrant on February 28, 2005.
10.19*	Arch Coal, Inc. (formerly Arch Mineral Corporation) Deferred Compensation Plan (incorporated herein by reference to Exhibit 4.1 of the Registration Statement on Form S-8 (Registration No. 333-68131) filed by the registrant on December 1, 1998).
10.20*	Arch Coal, Inc. 1997 Stock Incentive Plan (as Amended and Restated on February 28, 2002) (incorporated herein by reference to Exhibit 10.1 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002).
10.21*	Arch Mineral Corporation 1996 ERISA Forfeiture Plan (incorporated herein by reference to Exhibit 10.20 to the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.22*	Arch Coal, Inc. Outside Directors’ Deferred Compensation Plan effective January 1, 1999 (incorporated herein by reference to Exhibit 10.30 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.23*	Second Amendment to the Arch Mineral Corporation Supplemental Retirement Plan effective January 1, 1998(incorporated herein by reference to Exhibit 10.31 of the registrant’s Annual Report on Form 10-K for the year ended December 31, 1998).
10.24	Receivables Purchase Agreement, dated as of February 3, 2006, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, as issuer, the financial institutions from time to time party thereto, as LC Participants, and PNC Bank, National Association, as Administrator on behalf of the Purchasers and as LC Bank (incorporated herein by reference to Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on February 14, 2006).

Exhibit	Description
10.25*	Summary of the salaries for the named executive officers of the registrant (incorporated herein by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on February 24, 2006).
10.26*	Summary of the award levels and performance goals for the named executive officers of the registrant (incorporated herein by reference to Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on February 24, 2006).
10.27*	Form of Restricted Stock Unit Contract (incorporated herein by reference to Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on February 24, 2006).
10.28*	Form of Performance Unit Contract (incorporated herein by reference to Exhibit 10.7 to the registrant's Current Report on Form 8-K filed on February 24, 2006).
12.1	Computation of ratio of earnings to combined fixed charges and preference dividends.
13.1	Portions of the registrant's Annual Report to Stockholders for the year ended December 31, 2005.
21.1	Subsidiaries of the registrant.
23.1	Consent of Ernst & Young LLP.
24.1	Power of Attorney.
31.1	Rule 13a-14(a)/15d-14(a) Certification of Steven F. Leer.
31.2	Rule 13a-14(a)/15d-14(a) Certification of Robert J. Messey.
32.1	Section 1350 Certification of Steven F. Leer.
32.2	Section 1350 Certification of Robert J. Messey.

* Denotes management contract or compensatory plan arrangements.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) 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.

Arch Coal, Inc.

By: /s/ Steven F. Leer

Steven F. Leer
President and Chief Executive Officer

March 14, 2006

Signatures	Capacity
/s/ Steven F. Leer Steven F. Leer	President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ Robert J. Messey Robert J. Messey	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ John W. Lorson John W. Lorson	Controller (Principal Accounting Officer)
* James R. Boyd	Director
* Frank M. Burke	Director
/s/ John W. Eaves John W. Eaves	Executive Vice President and Chief Operating Officer and Director
* Patricia Fry Godley	Director
* Douglas H. Hunt	Director
* Thomas A. Lockhart	Director
* A. Michael Perry	Director
* Robert G. Potter	Director

Signatures	Capacity
* Theodore D. Sands	Director
* Wesley M. Taylor	Director

*By: /s/ Robert G. Jones

Robert G. Jones
Attorney-in-fact

Exhibit 2.2

**AMENDMENT NO. 1 TO THE
PURCHASE AND SALE AGREEMENT**

THIS AMENDMENT NO. 1 (this ***"Amendment"***) to that Purchase and Sale Agreement dated December 31, 2005 by and between the parties hereto (the ***"Agreement"***) is made and entered into on the 7th day of February, 2006, by and among Arch Coal, Inc., a Delaware corporation (***"Arch"***) and Magnum Coal Company, a Delaware corporation (***"Magnum"***).

RECITALS

WHEREAS, on December 31, 2005, Arch and Magnum entered into the Agreement; and

WHEREAS, Arch and Magnum desire to amend the Agreement as set forth below;

NOW, THEREFORE, the parties to this Amendment undertake and agree as follows:

1. DEFINITIONS

1.1 Terms capitalized but not defined herein have the meaning set forth in the Agreement.

2. WORKING CAPITAL ADJUSTMENT

2.1 The text contained in Section 3.2(b) shall be deleted in its entirety and replaced with the following text:

"The Adjusted Working Capital shall mean the Closing Working Capital reflected on the Actual Closing Working Capital Statement, adjusted as follows: increased by (i) all amounts paid by Arch on or prior to the Closing Date as advance royalties due in January 2006 and payable to Dingess Rum, ACIN or Kelly Hatfield, (ii) all current medical and other benefits claims that are incurred but not recorded, (iii) all accrued incentive compensation amounts, and (iv) the amount of the payment made by Arch for the January 4, 2006 payroll with respect to the Arch Companies, and decreased by net pension assets. For clarification, the Cash Balance provided for in Section 6.2(d)(j) shall not be factored into the calculation of Adjusted Working Capital in any way."

3. PERMITS

3.1 The text contained in Section 6.1(c) shall be deleted in its entirety and replaced with the following text:

"At the Closing or as soon as reasonably possible thereafter, (i) Arch shall assign or cause the assignment of all rights in and to, and the Company shall assume all obligations under, all Permits listed on Schedule 4.2.19(1) that are not listed as owned by one of the Arch Companies, in each case, pursuant to a Permit Assignment and Assumption Agreement, and (ii) the Company shall cooperate and shall cause the Arch Companies, as applicable, to cooperate, in good faith with Arch in connection with the filings that were made by Arch or one of its Affiliates prior to the Closing with respect to those permits set forth on Schedule 6.1(c) in order to assign such permits to Arch or one of its Affiliates."

4. NON-SOLICITATION

4.1 The text contained in Section 7(a) shall be deleted in its entirety and replaced with the following text:

"The Company agrees that it will not, and none of its Affiliates will, either for its own account or in connection with or on behalf of any Person at any time from the Execution Date until the date that is six months after the Closing Date (the ***"Restricted Period"***), directly or indirectly, either for itself or any other Person, (i) induce, solicit or entice or attempt to induce, solicit or entice any employee at such time of Arch or any of its Subsidiaries at such time to leave the employ thereof, or (ii) in any way interfere with the relationship between Arch or any of its Subsidiaries at such time and any of its employees at such time, it being understood that upon consummation of the sale contemplated in Article II, such restrictions are not applicable to the Arch Companies given that they will be Subsidiaries of the Company**.** Notwithstanding the foregoing, nothing in this paragraph shall prevent the Company from making general advertisements of employment opportunities or hiring any employee of Arch or its Subsidiaries who independent of any actions by the Company or any of its Affiliates, other than general advertisements, applies for a position with the Company."

4.2 The text contained in Section 7(b) shall be deleted in its entirety and replaced with the following text:

"Arch agrees that it will not, and none of its Affiliates will, either for his or its own account or in connection with or on behalf of any Person during the Restricted Period, directly or indirectly, either for itself or any other Person, (i) induce, solicit or entice or attempt to induce, solicit or entice any employee at such time of the Company or its Subsidiaries at such time to leave the employ of thereof, or (ii) in any way interfere with the relationship between the Company or any of its Subsidiaries at such time and any of its employees at such time. Notwithstanding the foregoing, nothing in this paragraph shall prevent Arch from making general advertisements of employment opportunities or hiring any employee of the Company or its Subsidiaries who independent of any actions by Arch or any of its Affiliates, other than general advertisements, applies for a position with Arch."

5. Arch Covenants

5.1 The text contained in Section 6.2(o) shall be deleted in its entirety

5.2 Arch shall pay to the Company a one-time payment of $34,117,000, such payment to be made by wire of immediately available funds within one business day from the execution of the Amendment, to an account specified in writing by the Company.

6. Integration

6.1 The text contained in Section 11.12 shall be deleted in its entirety.

7. Miscellaneous

7.1 Sections 11.4, 11.6, 11.7, 11.8 and 11.9 shall be applicable to the terms of this Amendment and are hereby incorporated by reference; provided that (a) any reference to "this Agreement" in such provisions of the Agreement shall be deemed for purposes of this Amendment to be a reference to "this Amendment" and (b) any other necessary changes relating to syntax, section or article references and other similar matters shall be deemed made.

7.2 The representations of the Company contained in Section 4.1 and of Arch contained in Section 4.2.2 shall be applicable to this Amendment and are hereby incorporated by reference, provided that (a) any reference to "this Agreement" in such provisions of the Agreement shall be deemed for purposes of this Amendment to be a reference to "this Amendment" and (b) any other necessary changes relating to syntax, section or article references and other similar matters shall be deemed made.

7.3 The Agreement, this Amendment and the Ancillary Documents (and any schedules, exhibits or annexes thereto), contain the entire agreement and understanding among the parties with respect to the subject matter hereof and supersede all prior agreements and understandings relating to such subject matter. Neither Party shall be liable or bound to the other Party in any manner by any representations, warranties or covenants relating to such subject matter except as specifically set forth herein or therein.

7.4 Except as set forth herein, the terms and provisions of the Agreement shall be unchanged by this Amendment and shall remain in full force and effect.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, this Agreement has been duly executed by the parties hereto as of this 7th day of February, 2006.

Arch Coal, Inc.

By: /s/ Robert G. Jones

Name: Robert G. Jones
Title: Vice President — Law

Magnum Coal Company

By: /s/ Paul H. Vining

Name: Paul H. Vining
Title: President and Chief Executive Officer

Exhibit 12.1

Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(Dollars in thousands, except ratios)				
Earnings:					
Pretax income (loss)	$ 3,473	$ 113,576	$ (2,870)	$ (21,562)	$ 2,509
Fixed charges, net of capitalized interest	93,435	73,639	59,656	55,194	68,424
Earnings before taxes and fixed charges	$ 96,908	$ 187,215	$ 56,786	$ 33,632	$ 70,933
Fixed charges:					
Interest expense	$ 72,408	$ 62,634	$ 50,133	$ 51,922	$ 64,211
Capitalized interest	4,248	162	—	711	—
Preferred dividends	15,579	7,187	6,589	—	—
Arch Western Resources LLC dividends on preferred membership interest	96	96	95	95	95
Portions of rent which represent an interest factor	5,351	3,722	2,839	3,177	4,118
Total fixed charges	$ 97,683	$ 73,801	$ 59,656	$ 55,905	$ 68,424
Ratio of earnings to fixed charges	(a)	2.54x	(a)	(a)	1.04x

(a) Ratio of earnings to combined fixed charges and preference dividends is computed on a total enterprise basis including our consolidated subsidiaries, plus our share of significant affiliates accounted for on the equity method that are 50% or greater owned or whose indebtedness has been directly or indirectly guaranteed by us. Earnings consist of income (loss) from continuing operations before income taxes and are adjusted to include fixed charges (excluding capitalized interest). Fixed charges consist of interest incurred on indebtedness, the portion of operating lease rentals deemed representative of the interest factor and the amortization of debt expense. Preference dividends are the amount of pre-tax earnings required to pay dividends on our outstanding preferred stock and Arch Western Resources, LLC's preferred membership interest. Combined fixed charges and preference dividends exceeded earnings by $775 for the year ended December 31, 2005, $2,870 for the year ended December 31, 2003 and $22,273 for the year ended December 31, 2002.

Part II — Annual Report

Management’s Discussion and Analysis of Financial Condition and Results of Operation

This document contains “forward-looking statements” — that is, statements related to future, not past, events. In this context, forward-looking statements often address our expected future business and financial performance, and often contain words such as “expects,” “anticipates,” “intends,” “plans,” “believes,” “seeks,” or “will.” Forward-looking statements by their nature address matters that are, to different degrees, uncertain. For us, particular uncertainties arise from changes in the demand for our coal by the domestic electric generation industry; from legislation and regulations relating to the Clean Air Act and other environmental initiatives; from operational, geological, permit, labor and weather-related factors; from fluctuations in the amount of cash we generate from operations; from future integration of acquired businesses; and from numerous other matters of national, regional and global scale, including those of a political, economic, business, competitive or regulatory nature. These uncertainties may cause our actual future results to be materially different than those expressed in our forward-looking statements. We do not undertake to update our forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by law.

Executive Overview

We focus on taking steps to increase shareholder returns by improving earnings, strengthening cash generation and improving productivity at our large-scale mines, while building on our strategic position in each of the nation’s principal low-sulfur coal basins. We believe that success in the coal industry is largely dependent on leadership in three crucial areas of performance — safety, environmental stewardship and shareholder return. At the same time, we are sustaining our long-standing focus on being a low-cost producer in the regions where we operate. We are also seeking to enhance our position as a preferred supplier to U.S. power producers, acting as a reliable and ethical partner. We plan to focus on organic growth by continuing to develop our existing reserve base, and we plan to evaluate acquisitions that represent a good fit with our existing operations.

Economic expansion and the high cost of competing fuels translated into strong coal demand throughout 2005. We estimate that coal-fuel electric generation increased 2.5% during 2005. In addition to increasing utilization at existing coal-fired power plants, U.S. power generators are moving forward with plans to build new coal plants. Already, projects have been announced that we believe could boost the installed coal-based generating units by approximately 80 gigawatts, or 25%, which could ultimately increase coal demand by as much as 300 million tons annually. In addition, interest in converting coal into transportation fuels and synthetic natural gas has increased from prior years.

Meanwhile, coal production during 2005 struggled to keep pace with increased demand, with consumption outstripping supply for the third consecutive year, according to our estimates. We estimate that utility coal stockpiles ended 2005 at their lowest year-end levels in decades at approximately 33 days of supply, or 37% below the 15-year average. We believe stockpile levels are particularly low in the midwestern United States, where coal fuel costs have boosted wholesale power sales and rail disruptions have constrained coal deliveries. We believe that strong coal demand and continuing supply constraints will result in a multi-year effort to restore utility stockpiles to targeted levels, particularly in the midwestern United States traditionally served by coal producers operating in the Powder River Basin.

Rail service disruptions experienced throughout the industry during 2004 continued for much of 2005 and resulted in missed shipments in all of our operating regions, including some of our highest margin coal in Central Appalachia. Severe weather and the resulting maintenance efforts exacerbated the railroad disruptions already existing as a result of inadequate staffing at the railroads, equipment shortages and an overall increase in rail shipments. We expect continued challenges during 2006 due to rail shortages, and we continue to work with our customers and the railroads in an effort to minimize the impact of future disruptions.

Overall, 2005 was one of the most eventful years in the history of our company. We believe our accomplishments during 2005, particularly those during the last quarter, have strengthened our strategic, operational and financial position within the U.S. coal industry.

Results of Operation

Recent Developments

On October 27, 2005, we conducted a precautionary evacuation of our West Elk mine after we detected elevated readings of combustion-related gases in an area of the mine where we had completed mining activities but had not yet removed all remaining longwall equipment. We have successfully controlled the combustion-related gases, re-entered and rehabilitated the mine, and we have taken actions to commence longwall mining which we expect to begin late in the first quarter. We estimate that the financial impact of idling the mine and fighting the fire during the fourth quarter of 2005 was $33.3 million in reduced operating profit. We will continue to be negatively impacted during the first quarter of 2006 until the longwall is back in production and the mine is operating at full capacity.

On December 30, 2005, we completed a reserve swap with Peabody Energy and sold to Peabody a rail spur, rail loadout and idle office complex located in the Powder River Basin for a purchase price of $84.6 million, resulting in a gain of $46.5 million. In the reserve swap, we exchanged 60 million tons of coal reserves near the former North Rochelle mine for a similar block of 60 million tons of coal reserves more strategically positioned relative to our Black Thunder mining complex. We believe the reserve exchange will provide us with a more efficient mine plan.

On December 31, 2005, we accepted for conversion 2,724,418 shares of preferred stock, representing approximately 95% of the preferred stock issued and outstanding on that date, pursuant to the terms of a conversion offer. As a result of the conversion offer, we issued an aggregate of 6,534,517 shares of common stock pursuant to the conversion terms of the preferred stock and an aggregate premium of 119,602 shares of common stock. We recorded the issuance of the aggregate premium as a preferred stock dividend of $9.5 million. As of March 1, 2006, 150,508 shares of preferred stock remain outstanding.

On December 31, 2005, we sold all of the stock of three subsidiaries and their four associated mining operations and coal reserves in Central Appalachia to Magnum Coal Company. The three subsidiaries include Hobet Mining, Apogee Coal Company and Catenary Coal Company, which include the Hobet 21, Arch of West Virginia, Samples and Campbells Creek mining operations. Included in the sale were a total of 455.0 million tons of reserves. For the year ended December 31, 2005, these subsidiaries sold 12.7 million tons of coal, had revenues of $509.8 million and incurred a loss from operations of $8.3 million, for the year ended December 31, 2004, these subsidiaries sold 14.0 million tons of coal, had revenues of $475.1 million and incurred a loss from operations of $3.8 million, and for the year ended December 31, 2003, these subsidiaries sold 14.4 million tons of coal, had revenues of $424.3 million and incurred a loss from operations of $65.6 million. As a result of the sale, Magnum acquired all of the assets and liabilities of the subsidiaries including various employee liabilities of idle union properties whose former employees were signatory to a United Mine Workers' Association contract. We recognized a gain of $7.5 million as a result of the transaction.

On February 10, 2006, we established a $100 million accounts receivable securitization program. Under the program, undivided interests in a pool of eligible trade receivables are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit. Purchases by the conduit are financed with the sale of highly-rated commercial paper. We may use the proceeds from the sale of accounts receivable in the program as an alternative to other forms of debt.

On February 23, 2005, our board of directors elected Steven F. Leer, our president and chief executive officer, as chairman of the board of directors, effective April 28, 2006. Mr. Leer will continue to act as president and chief executive officer until April 28, 2006, at which time Mr. Leer will assume the responsibilities of chairman of the board and chief executive officer. In addition, the board of directors elected John W. Eaves, our executive vice president and chief operating officer, as president, effective April 28, 2006. The board of directors also increased the size of the board of directors to eleven and elected Mr. Eaves to fill the newly-created vacancy, effective immediately.

Items Affecting Comparability of Reported Results

The comparison of our operating results for the years ended December 31, 2005, 2004 and 2003 is affected by the following significant items:

	Year Ended December 31,		
	2005	2004	2003
		(Amounts in millions)	
Operating income:			
Gain on sale of Powder River Basin assets	$ 46.5	$ —	$ —
Gain on sale of Central Appalachian operations	7.5	—	—
Reduced operating profit from West Elk thermal event	(33.3)	—	—
Arbitration and legal settlements	(16.0)	—	—
Gain on land, equipment and facility sales	28.2	6.7	3.8
Mark-to-market adjustments on sulfur dioxide and coal derivatives	(19.7)	—	—
Long-term incentive compensation expense	(19.5)	(5.5)	(16.2)
Establishment of charitable foundation	(5.0)	—	—
Gain on sale of investment in Natural Resource Partners L.P.	—	91.3	42.7
Severance costs/reduction in workforce	—	(2.1)	(2.6)
Net increase (decrease) in operating income	$ (11.3)	$ 90.4	$ 27.7
Other:			
Gain (loss) from mark-to-market adjustments on interest rate swaps that no longer qualify as hedges	(2.3)	0.9	13.4
Net increase (decrease) in pre-tax income	$ (13.6)	$ 91.3	$ 41.1

Gain on sale of Powder River Basin assets. As discussed above under “Recent Developments,” on December 30, 2005, we completed a reserve swap with Peabody Energy and sold to Peabody a rail spur, rail loadout and an idle office complex, all of which is located in the Powder River Basin for a purchase price of $84.6 million. As a result of the transaction, we recognized a gain of $46.5 million which we recorded as a component of other operating income. Due to the similarity of the exchanged reserves, the reserves received were recorded at the net book value of the reserves transferred.

Gain on sale of Central Appalachian assets. As discussed above under “Recent Developments,” on December 31, 2005, we sold all of the stock of three subsidiaries and their associated mining operations and coal reserves in Central Appalachia to Magnum Coal Company. In accordance with the terms of the transaction, we agreed to pay $50.2 million to Magnum in 2006 which we have recorded in current liabilities at December 31, 2005. We recorded a loss of $65.4 million related to firm purchase commitments to supply below-market sales contracts that can no longer be sourced from our production as a result of the sale of these operations to Magnum. We recorded the loss related to the below-market legacy sales contracts as an accrued expense at December 31, 2005. The net book value of the subsidiaries sold was a net liability of $123.1 million.

Reduced operating profit from West Elk thermal event. As discussed above under "Recent Developments," we performed a cautionary evacuation of our West Elk mine during the fourth quarter of 2005.

Arbitration and legal settlements. In December 2005, we settled a dispute with one of our landowners. For more information concerning these proceedings, you should see "Management's Discussion and Analysis of Financial Condition — Contingencies" below. As a result of the settlement, we recognized an expense of $16.0 million which we recorded as a component of other expenses.

Gain on land, equipment and facility sales. During the years ended December 31, 2005, 2004 and 2003, we recognized gains on several land, equipment and facility sales, certain of which are noted below. We recorded these gains as a component of other income. During 2005, we assigned our rights and obligations on several parcels of land to a third party in a gain of $6.3 million, we recognized a gain of $7.3 million on the sale a dragline and sold surface land resulting in a gain of $9.0 million. During 2004 and 2003, we recognized gains from the sale of land associated with our idle properties which we recorded as a component of other operating income.

Unrealized losses on sulfur dioxide and coal derivatives. We recorded certain expenses related to changes in fair market value of sulfur dioxide and coal derivatives during the period as a component of other operating income. For more information about these expenses, you should see "Management's Discussion and Analysis of Financial Condition — Liquidity and Capital Resources" below.

Establishment of charitable foundation. In December 2005, we contributed $5.0 million to fund the new Arch Coal Foundation, which will support a range of charitable and community-oriented organizations and programs.

Long-term incentive compensation expense. During 2004, we granted an award of 220,766 shares of performance-contingent phantom stock that vest upon the achievement of a pre-determined average closing price of our common stock for a period of 20 consecutive trading days during the five year period following the date of grant. During the first quarter of 2005, the shares vested, and we paid the award in a combination of shares of our common stock and cash. As a result, we recognized a $9.9 million expense. In 2005, we granted another award of performance-contingent phantom stock of up to 252,600 units that vest upon the achievement of a pre-determined average closing price of our common stock for a period of 20 consecutive trading days and the attainment of certain EBITDA levels. During the fourth quarter of 2005, we determined that based on the closing price of our common stock and the forecast EBITDA projections, it was appropriate to accrue a ratable portion of the award over the projected period of attainment. We recognized $4.5 million of expense related to this award. Of the aggregate amounts we recognized during 2005, we recorded $13.6 million as a component of selling, general and administrative expense and $0.8 million as a component of cost of coal sales. The remaining expense of $5.1 million during 2005 relates to other incentive compensation plans. During 2004, we recorded an aggregate expense of $5.5 million related to awards we granted under our long-term incentive compensation plans. Awards under these plans included restricted stock units that vest ratably over a three-year period and performance unit tied to our performance against pre-established targets, including certain financial, safety and environmental performance targets during the three-year period ending December 31, 2006. During the fourth quarter of 2003, our board of directors approved awards under a four-year performance unit plan that began in 2000. We recorded an aggregate expense of $16.2 million in 2003 related to those awards.

Gain on sale of investment in Natural Resource Partners L.P. During 2004, we sold our remaining limited partnership units of Natural Resource Partners L.P. resulting in proceeds of approximately $111.4 million and a gain of $91.3 million. During 2003, we sold our general partner interest and subordinated units resulting in proceeds of $115.0 million and a gain of $42.7 million.

Severance costs/reduction in workforce. During 2004, Canyon Fuel, for which we accounted under the equity method through July 31, 2004, began the process of idling its Skyline Mine. Canyon Fuel completed the idling process in May 2004. In connection with this process, Canyon Fuel incurred severance costs of $3.2 million for the year ended December 31, 2004. We reflected our share of these costs totaling $2.1 million as a component of income from equity investments.

During the year ended December 31, 2003, we instituted cost reduction efforts throughout our operations. These cost reduction efforts included the termination of approximately 100 employees at our corporate office and Central Appalachia mining operations. Of the expense recognized, we recorded $1.6 million as a component of cost of coal sales and the remainder as a component of selling, general and administrative expenses.

Unrealized gain on interest rate swaps that no longer qualified as hedges. We entered into several interest rate swap agreements to hedge the variable rate interest payments due under Arch Western's term loans. Subsequent to the repayment of those term loans, the swaps no longer qualified for hedge accounting under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," which we refer to as FAS 133. As such, we recognized income related to favorable changes in the market value of the swap agreements as a component of other non-operating income. During the year ended December 31, 2003, we recognized income of $13.4 million related to the unrealized gains on these swap agreements.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

The following discussion summarizes our operating results for the year ended December 31, 2005 and compares those results to our operating results for the year ended December 31, 2004.

Revenues. The following table summarizes the number of tons we sold during the year ended December 31, 2005 and the sales associated with those tons and compares those results to the comparable information for the year ended December 31, 2004:

	Year Ended December 31,		Increase (Decrease)	
	2005	2004	$	%
	(Amounts in thousands, except per ton data)			
Coal sales	$ 2,508,773	$ 1,907,168	$ 601,605	31.5%
Tons sold	140,202	123,060	17,142	13.9%
Coal sales realization per ton sold	$ 17.89	$ 15.50	$ 2.39	15.4%

The following table shows the number of tons sold by operating segment during the year ended December 31, 2005 and compares those amounts to the comparable information for the year ended December 31, 2004:

	Tons Sold		% of Total	
	2005	2004	2005	2004
	(Amounts in thousands)			
Powder River Basin	91,471	81,857	65.2%	66.5%
Central Appalachia	30,532	30,008	21.8%	24.4%
Western Bituminous Region	18,199	11,195	13.0%	9.1%
Total	140,202	123,060	100.0%	100.0%

Coal sales. The increase in our coal sales resulted from a combination of increased volumes, higher pricing, and the acquisitions of Triton in the Powder River Basin on August 20, 2004 and the remaining 35% interest in Canyon Fuel in the Western Bituminous region on July 31, 2004.

Our volume in the Powder River Basin increased 11.7% during 2005 compared to 2004. Our volume in Central Appalachia remained relatively flat, increasing 1.7% in 2005 compared to 2004. In the Western Bituminous region, our volume increased 62.6% during the same period. In addition to an overall increase in demand, volumes in the Powder River Basin and the Western Bituminous region also benefited from the acquisitions described above.

Our per ton realizations increased due primarily to higher contract prices in all three segments. In the Powder River Basin, our per ton realization increased 16.3% due to increased base pricing and above-market pricing on certain contracts acquired in our Triton acquisition as well as higher sulfur dioxide quality premiums resulting from higher sulfur dioxide emission allowance prices. Our per ton realization in the Central Appalachia Basin increased 17.7% as both contract and spot market prices were higher than in 2004. Additionally, we received higher sales prices on our metallurgical coal sales in 2005 compared to 2004. The Western Bituminous region's per ton realization increased 24.7%. In addition to higher contract pricing, per ton realization in the Western Bituminous region was also affected by our acquisition of the remaining 35% interest in Canyon Fuel during the third quarter of 2004.

On a consolidated basis, the increase in per ton realization was partially offset by the change in mix of sales volumes among our operating regions. As reflected in the table above, Central Appalachia volumes (which have the highest average realization) were relatively flat in 2005 while volumes from lower realization regions (the Powder River Basin and Western Bituminous region) increased from 2004.

Operating costs and expenses. The following table summarizes our operating costs and expenses for the year ended December 31, 2005 and compares those results to the comparable information for the year ended December 31, 2004:

	Year Ended December 31,		Increase (Decrease)	
	2005	2004	$	%
		(Amounts in thousands)		
Cost of coal sales	$ 2,174,007	$ 1,638,646	$ 535,361	32.7%
Depreciation, depletion and amortization	212,301	166,322	45,979	27.6%
Selling, general and administrative expenses	91,568	57,975	33,593	57.9%
Other expenses	80,983	35,758	45,225	126.5%
	$ 2,558,859	$ 1,898,701	$ 660,158	34.8%

Cost of coal sales. The increase in cost of coal sales is primarily due to the acquisitions of Triton in the Powder River Basin on August 20, 2004 and the remaining 35% interest in Canyon Fuel in the Western Bituminous region on July 31, 2004, along with an increase in sales-sensitive costs resulting from the increase in revenue discussed above. In addition to the acquisitions of Triton and Canyon Fuel during the third quarter of 2004, our costs of coal sales were affected by the following:

- Production taxes and coal royalties, which we incur as a percentage of coal sales realization, increased $100.3 million during 2005 compared to 2004.
- During 2005, our Central Appalachia operations incurred higher costs related to additional processing necessary for coal sold in metallurgical markets and to the advancement of our Mingo Logan mine into less favorable geological conditions.
- The cost of purchased coal increased $120.5 million, reflecting a combination of increased purchase volumes and higher spot market prices that were prevalent during 2005 compared to 2004. During 2005, we utilized purchased coal to fulfill steam coal sales commitments in order to direct more of our produced coal into the metallurgical markets and to make up for production shortfalls from our Central Appalachia operations.
- Repairs and maintenance costs increased $46.7 million during 2005 compared to 2004 due to increased repair and maintenance activity in 2005 resulting from the acquisitions in 2004 described above.
- Costs for diesel fuel, explosives and utilities increased $29.4 million, $12.6 million and $6.4 million, respectively, in 2005 compared to 2004 as a result of higher commodity pricing and increased usage resulting from the acquisitions in 2004 described above.
- Costs for operating supplies increased $38.5 million due partially to increased steel prices during 2005 compared to 2004 and increased usage resulting from the acquisitions in 2004 described above.

Depreciation, depletion and amortization. The increase in depreciation, depletion and amortization is due primarily to the property additions resulting from the acquisitions made during the third quarter of 2004 and to higher capital expenditures during 2005.

Selling, general and administrative expenses. Selling, general and administrative expenses increased during 2005 due primarily to $14.9 million expense we recognized for the performance-contingent phantom stock awards to certain employees. In addition, when comparing 2005 to 2004, costs increased as a result of higher contract services including legal and professional fees ($5.2 million), employee severance expense ($1.3 million), the establishment of a charitable foundation during the fourth quarter of 2005 ($5.0 million) and executive deferred compensation expense ($4.6 million).

Other expenses. Other expenses increased as a result of the settlement with a landowner noted in “Items Affecting Comparability of Results” which resulted in a $16.0 million expense as well as an expense of $19.7 million recognized to reflect the change in fair value of sulfur dioxide swaps, sulfur dioxide put options and coal swaps which are derivatives but do not qualify for hedge accounting treatment.

Our operating costs (reflected below on a per-ton basis) are defined as including all mining costs, which consist of all amounts classified as cost of coal sales (except pass-through transportation costs) and all depreciation, depletion and amortization attributable to mining operations.

	Year Ended December 31,		Increase (Decrease)	
	2005	2004	$	%
Powder River Basin	$ 7.21	$ 6.19	$ 1.02	16.5%
Central Appalachia	43.24	34.84	8.40	24.1%
Western Bituminous Region	16.40	15.71	0.69	4.4%

Powder River Basin — On a per ton basis, operating costs increased in the Powder River Basin primarily due to higher diesel fuel costs ($0.15 per ton), higher repairs and maintenance costs ($0.13 per ton), higher depreciation, depletion and amortization costs ($0.20 per ton), and increased production taxes and coal royalties ($0.41 per ton). Additionally, average costs were higher due to the integration of the North Rochelle mine into our Black Thunder mine in the third quarter of 2004. These costs would have been largely offset by increased productivity had rail service not adversely impacted volumes during the year.

Central Appalachia — Operating cost per ton increased due to increased costs for coal purchases ($4.30 per ton), increased labor costs ($1.12 per ton), increased costs for operating supplies ($0.33 per ton), increased diesel fuel ($0.35 per ton) and production taxes and coal royalties ($0.58 per ton) as well as the increased preparation costs for metallurgical coal discussed above. Additionally, during 2005 our Mingo Logan mine has moved into less favorable geological conditions than during 2004, resulting in higher costs.

Western Bituminous Region — Operating cost per ton increased primarily due to the West Elk thermal event noted in “Items Affecting Comparability of Reported Results”. As a result of the temporary idling of the mine, we incurred higher expenses along with reduced production.

Other operating income. The following table summarizes our other operating income for the year ended December 31, 2005 and compares that information to the comparable information for the year ended December 31, 2004:

	Year Ended December 31,		Increase (Decrease)	
	2005	2004	$	%
	(Amounts in thousands)			
Income from equity investments	$ —	$ 10,828	$ (10,828)	(100.0)%
Gain on sale of Powder River Basin assets	46,547	—	46,547	100.0%
Gain on sale of Central Appalachian operations	7,528	—	7,528	100.0%
Gain on sale of investment in Natural Resource Partners L.P.	—	91,268	(91,268)	(100.0)%
Other operating income	73,868	67,483	6,385	9.5%
	$ 127,943	$ 169,579	$ (41,636)	(24.6)%

Income from equity investments. Income from equity investments for 2004 consisted of $8.4 million from our investment in Canyon Fuel and $2.4 million from our investment in Natural Resource Partners L.P. prior to our sale of those limited partnership units in March 2004.

Gain on sale. You should see “Items Affecting Comparability of Reported Results” for more information about the gains on the sale of our Powder River Basin assets, Central Appalachian operations and our investment in Natural Resource Partners L.P.

Other operating income. Gains on sales of assets other than those noted above were $28.2 million in 2005, compared to $6.7 million in 2004. The significant items comprising the gain are discussed in “Items Affecting Comparability of Reported Results”. This increase was partially offset by the elimination of administrative fees from Canyon Fuel subsequent to our acquisition of the remaining 35% interest during the third quarter of 2004 which resulted in $4.8 million of income in 2004, reduced bookout income, related to the netting of coal sales and purchase contracts with the same counterparty, of $9.4 million compared to the prior year and a $6.5 million decrease in 2005 compared to 2004 of previously-deferred gains from our sales of limited partnership units in Natural Resource Partners L.P. in 2003 and 2004. These deferred gains are being recognized over the terms of our leases with Natural Resource Partners L.P.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2005 and compares that information to the comparable information for the year ended December 31, 2004:

	Year Ended December 31,		Increase (Decrease) in Net Income	
	2005	2004	$	%
	(Amounts in thousands)			
Interest expense	$ (72,409)	$ (62,634)	$ (9,775)	(15.6)%
Interest income	9,289	6,130	3,159	51.5%
	$ (63,120)	$ (56,504)	$ (6,616)	(11.7)%

Interest expense. The increase in interest expense results from a higher amount of average borrowings in 2005 as compared to the same period in 2004. In addition, we recognized $1.4 million of interest expense associated with state tax assessments.

Interest income. The increase in interest income resulted primarily from interest on short-term investments.

Other non-operating income and expense. The following table summarizes our other non-operating income and expense for the year ended December 31, 2005 and compares that information to the comparable information for the year ended December 31, 2004:

	Year Ended December 31,		Increase (Decrease) in Net Income	
	2005	2004	$	%
	(Amounts in thousands)			
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	$ (7,740)	$ (9,010)	$ 1,270	14.1%
Other non-operating income (expense)	(3,524)	1,044	(4,568)	(437.5)%
	$ (11,264)	$ (7,966)	$ (3,298)	(41.4)%

Amounts reported as non-operating consist of income or expense resulting from our financing activities other than interest. As described above, our results of operations include expenses of $7.7 million for 2005 and $9.0 million for 2004 related to the termination of hedge accounting and resulting amortization of amounts that had previously been deferred. Other non-operating income includes mark-to-market adjustments related to certain swap activity that does not qualify for hedge accounting under FAS 133.

Income taxes. The following table summarizes our income tax benefit for the year ended December 31, 2005 and compares that information to the comparable information for the year ended December 31, 2004:

	Year Ended December 31,		Increase (Decrease)	
	2005	2004	$	%
	(Amounts in thousands)			
Income tax benefit	$ 34,650	$ 130	$ 34,520	NA

Our effective tax rate is sensitive to changes in estimates of annual profitability and percentage depletion. The increase in the income tax benefit in 2005 as compared to 2004 is primarily the result of the taxable income from non-mining sources from the sale of the Natural Resource Partners L.P. limited partnership units in the first quarter of 2004. The benefit for 2005 is the result of our taxable income and the effect of percentage depletion on our results.

Deferred tax assets and liabilities are recorded at the maximum effective tax rate. Statement of Financial Accounting Standards No. 109, “Accounting for Income Taxes,” requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. We have historically been subject to alternative minimum tax, which we refer to as AMT, and it is more likely than not that we will remain an AMT taxpayer in the foreseeable future. Valuation allowances are established against deferred tax assets so as to value the asset to an amount that is realizable, as described in

"Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies."

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

The following discussion summarizes our operating results for the year ended December 31, 2004 and compares those results to our operating results for the year ended December 31, 2003.

Revenues. The following table summarizes the number of tons we sold during the year ended December 31, 2004 and the sales associated with those tons and compares those results to the comparable information for the year ended December 31, 2003:

	Year Ended December 31,		Increase (Decrease)	
	2004	2003	$	%
	(Amounts in thousands, except per ton data)			
Coal sales	$ 1,907,168	$ 1,435,488	$ 471,680	32.9%
Tons sold	123,060	100,634	22,426	22.3%
Coal sales realization per ton sold	$ 15.50	$ 14.26	$ 1.24	8.7%

The following table shows the number of tons sold by operating segment during the year ended December 31, 2004 and compares those amounts to the comparable information for the year ended December 31, 2003:

	Tons Sold		% of Total	
	2004	2003	2004	2003
	(Amounts in thousands)			
Powder River Basin	81,857	64,050	66.5%	63.6%
Central Appalachia	30,008	29,667	24.4%	29.5%
Western Bituminous Region	11,195	6,917	9.1%	6.9%
Total	123,060	100,634	100.0%	100.0%

Coal sales. The increase in coal sales resulted from the combination of increased volumes, higher pricing and the acquisitions of Triton and the remaining 35% interest in Canyon Fuel during the third quarter of 2004.

Our volume in the Powder River Basin increased 27.8%. In the Central Appalachian region, our volume increased 1.2%, and in the Western Bituminous region, our volume increased 61.9%. In addition to an overall increase in demand, volumes in both the Powder River Basin and the Western Bituminous region also benefited from the acquisitions described above.

Our per ton realizations increased due primarily to higher contract prices in all three segments. In the Powder River Basin, our per ton realization increased 11.3% due to above-market pricing on certain contracts acquired in the Triton acquisition. The Central Appalachia region experienced the largest per ton realization increase (an increase of 21.3%), as both contract and spot market prices were higher than in 2003. Additionally, a higher percentage of our sales were metallurgical coal sales in 2004 as compared to 2003. The Western Bituminous region's per ton realization increased 13.4%. In addition to higher contract pricing, per ton realization in the Western Bituminous region was also affected by our acquisition of the remaining 35% interest in Canyon Fuel during the third quarter of 2004.

On a consolidated basis, the increase in per ton realization was partially offset by the change in mix of sales volumes among our operating regions. As reflected in the table above, Central Appalachia volumes (which have the highest average realization) remained relatively flat while volumes from lower realization regions (the Powder River Basin and Western Bituminous region) increased from 2003.

Operating costs and expenses. The following table summarizes our operating costs and expenses for the year ended December 31, 2004 and compares those results to the comparable information for the year ended December 31, 2003:

	Year Ended December 31,		Increase (Decrease)	
	2004	2003	$	%
	(Amounts in thousands)			
Cost of coal sales	$ 1,638,646	$ 1,280,608	$ 358,038	28.0%
Depreciation, depletion and amortization	166,322	158,464	7,858	5.0%
Selling, general and administrative expenses	57,975	60,159	(2,184)	(3.6)%
Other expenses	35,758	18,245	17,513	96.0%
	$ 1,898,701	$ 1,517,476	$ 381,225	25.1%

Cost of coal sales. The increase in cost of coal sales is primarily due to the increase in revenues discussed above. Our costs of coal sales were affected by the following:

- Production taxes and coal royalties, which we incur as a percentage of coal sales realization, increased $71.8 million.
- Poor rail performance during 2004 resulted in missed shipments and disruptions in production.
- Our Central Appalachia operations incurred higher costs related to additional processing necessary to sell coal in metallurgical markets.
- The cost of purchased coal increased $105.9 million, reflecting a combination of increased purchase volumes and higher spot market prices that were prevalent during 2004. During 2004, we utilized purchased coal to fulfill steam coal sales commitments in order to direct more of our produced coal into the metallurgical markets.
- Costs for explosives increased $9.5 million, and diesel fuel increased $22.4 million as a result of higher commodity prices.
- Costs for operating supplies increased $16.9 million due primarily to increased commodity and steel prices during the year.
- Repairs and maintenance costs increased $21.3 million due partially to the acquisitions made during the third quarter of 2004.
- During the first quarter of 2004, we reflected the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003, in accordance with the provisions of FASB Staff Position No. FAS 106-2, “Accounting and Disclosure Requirements related to the Medicare Prescription Drug,

Improvement and Modernization Act of 2003." Incorporation of the provisions of the act resulted in a $68.0 million reduction of our postretirement medical benefit obligation. Postretirement medical expenses for fiscal year 2004 after incorporation of the provisions of the act resulted in $18.2 million less expense than that previously anticipated (substantially all of which is recorded as a component of cost of coal sales). The benefit for the year ending December 31, 2004 was partially offset by increased costs resulting from changes to other actuarial assumptions that were incorporated at the beginning of the year.

Depreciation, depletion and amortization. The increase in depreciation, depletion and amortization is due primarily to the property additions resulting from the acquisitions made during the third quarter of 2004.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased due to a four year performance unit plan award that began in 2000 and approved by our board of directors in 2003. We recorded an aggregate expense of $16.2 million related to that award in 2003. During 2004, we recorded an aggregate expense of $5.5 million related to awards we granted under our long-term incentive compensation plans. Awards under these plans included restricted stock units that vest ratably over a three-year period and performance units tied to our performance against pre-established targets, including certain financial, safety and environmental performance targets during the three-year period ending December 31, 2006. Partially offsetting the decrease were higher legal and professional fees ($2.1 million), franchise taxes ($2.9 million) and higher expenses resulting from amounts expected to be earned under our annual incentive plans ($3.7 million).

Other expenses. The increase in other expenses is primarily a result of an increase in bookout costs related to the netting of coal sales and purchase contracts with the same counterparty.

Our operating costs (reflected below on a per-ton basis) are defined as including all mining costs, which consist of all amounts classified as cost of coal sales (except pass-through transportation costs) and all depreciation, depletion and amortization attributable to mining operations.

	Year Ended December 31,		Increase (Decrease)	
	2004	**2003**	**$**	**%**
Powder River Basin	$ 6.19	$ 5.45	$ 0.74	13.6%
Central Appalachia	$ 34.84	$ 30.87	$ 3.97	12.9%
Western Bituminous Region	$ 15.71	$ 15.41	$ 0.30	1.9%

Powder River Basin — On a per-ton basis, operating costs increased in the Powder River Basin primarily due to increased cost of purchased coal ($0.31 per ton), increased production taxes and coal royalties ($0.17 per ton) and to the higher explosives and diesel fuel costs discussed above. Additionally, average costs were higher due to the integration of the North Rochelle mine into our Black Thunder mine.

Central Appalachia — Operating cost per ton increased due to increased costs for coal purchases ($2.52 per ton), increased diesel fuel ($0.38 per ton) and production taxes and coal royalties ($0.49 per ton) as well as the increased preparation costs for metallurgical coal discussed above. Additionally, poor rail performance at our Central Appalachia operations resulted in disruptions in production. As many of our costs are fixed in nature, the reduced volume did not result in reduced overall costs.

Western Bituminous Region — Operating cost per ton increased primarily due to increased production taxes and coal royalties ($0.27 per ton).

Other operating income. The following table summarizes our other operating income for the year ended December 31, 2004 and compares that information to the comparable information for the year ended December 31, 2003:

	Year Ended December 31,		Increase (Decrease)	
	2004	2003	$	%
	(Amounts in thousands)			
Income from equity investments	$ 10,828	$ 34,390	$ (23,562)	(68.5)%
Gain on sale of investment in Natural Resource Partners L.P.	91,268	42,743	48,525	113.5%
Other operating income	67,483	45,226	22,257	49.2%
	$ 169,579	$ 122,359	$ 47,220	38.6%

Income from equity investments. Income from equity investments for 2004 consisted of $8.4 million from our investment in Canyon Fuel and $2.4 million from our investment in Natural Resource Partners L.P. prior to the sale of those limited partnership units in March 2004. For 2003, income from equity investments consisted of $19.7 million of income from our investment in Canyon Fuel and $14.7 million from our investment in Natural Resource Partners L.P. The decline in income from our investment in Canyon Fuel results from the consolidation of Canyon Fuel into our financial statements subsequent to the July 31, 2004 purchase date, lower production and sales levels at Canyon Fuel prior to the acquisition and additional costs related to idling the Skyline Mine, including the severance costs noted above.

You should see “Items Affecting Comparability of Reported Results” for more information about the gains on the sale of our Powder River Basin assets, Central Appalachian operations and our investment in Natural Resource Partners L.P.

Other operating income. The increase in other operating income is primarily due to the recognition in 2004 of $13.9 million of previously-deferred gains from our sales of limited partnership units in Natural Resource Partners L.P. in 2003 and 2004. These deferred gains are being recognized over the terms of our leases with Natural Resource Partners L.P. The increase is also due to gains recognized on land sales of $6.7 million in 2004 compared to $3.8 million in 2003.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2004 and compares that information to the comparable information for the year ended December 31, 2003:

	Year Ended December 31,		Increase (Decrease) in Net Income	
	2004	2003	$	%
	(Amounts in thousands)			
Interest expense	$ (62,634)	$ (50,133)	$ (12,501)	(24.9)%
Interest income	6,130	2,636	3,494	132.5%
	$ (56,504)	$ (47,497)	$ (9,007)	(19.0)%

The increase in interest expense results from a higher average interest rate in the first six months of 2004 as compared to the same period in 2003 as well as a higher amount of average borrowings from August through December 2004 as compared to the prior year. In 2004, our outstanding borrowings consisted primarily of fixed rate borrowings, while borrowings in the first half of 2003 were primarily variable rate borrowings. Short-term interest rates in 2003 were lower than the fixed rate borrowing that made up the majority of average debt balances in 2004.

The increase in interest income is partly due to interest on the federal income tax refunds discussed above. The remaining increase results primarily from interest on short-term investments.

Other non-operating income and expense. The following table summarizes our other non-operating income and expense for the year ended December 31, 2004 and compares that information to the comparable information for the year ended December 31, 2003:

	Year Ended December 31,		Increase (Decrease) in Net Income	
	2004	2003	$	%
	(Amounts in thousands)			
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	$ (9,010)	$ (8,955)	$ (55)	(0.6)%
Other non-operating income	1,044	13,211	(12,167)	(92.1)%
	$ (7,966)	$ 4,256	$ (12,222)	(287.2)%

Amounts reported as non-operating consist of income or expense resulting from our financing activities other than interest. As described above, we recorded expenses of $8.3 million for the year ended December 31, 2004 and $4.3 million for the year ended December 31, 2003 related to the termination of hedge accounting and resulting amortization of amounts that had previously been deferred. Additionally, we incurred expenses of $0.7 million for the year ended December 31, 2004 and $4.7 million for the year ended December 31, 2003 related to early debt extinguishment costs.

Other non-operating income in 2003 was primarily from mark-to-market adjustments on swaps as described above. During 2003, we terminated these positions or entered into offsetting positions.

Income taxes. The following table summarizes our income tax benefit for the year ended December 31, 2004 and compares that information to the comparable information for the year ended December 31, 2003:

	Year Ended December 31,		Increase (Decrease)	
	2004	2003	$	%
	(Amounts in thousands)			
Income tax benefit	$ 130	$ 23,210	$ (23,080)	(99.4)%

Our effective tax rate is sensitive to changes in estimates of annual profitability and percentage depletion. The income tax benefit recorded in 2004 is due primarily to a $7.1 million benefit due to favorable tax settlements and a $9.7 million reduction in income tax reserves associated with the completion of the 1999 through 2002 federal income tax audits. The change is also the result of the tax benefit from percentage depletion offset by the tax impact from the sales of limited partnership units in Natural Resource Partners L.P. throughout 2004.

Liquidity and Capital Resources

Our primary sources of cash include sales of our coal production to customers, sales of assets and debt and equity offerings related to significant transactions. Excluding any significant mineral reserve acquisitions, we generally satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations. Our ability to satisfy debt service obligations, to fund planned capital expenditures, to make acquisitions and to pay dividends will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry and financial, business and other factors, some of which are beyond our control. We had no loans outstanding under our revolving credit agreement as of December 31, 2005.

The following is a summary of cash provided by or used in each of the indicated types of activities during the past three years:

	Year Ended December 31,		
	2005	2004	2003
	(Amounts in thousands)		
Cash provided by (used in):			
Operating activities	$ 254,607	$ 148,728	$ 162,361
Investing activities	(291,543)	(597,294)	6,832
Financing activities	(25,730)	517,192	75,791

Cash provided by operating activities increased during 2005 compared to 2004 primarily as a result of improved performance at our operations in addition to a decreased investment in working capital. While trade accounts receivable and inventory represented the largest use of funds, increasing by $86.8 million in 2005 compared to an increase of $44.0 million in 2004, those increases were offset by an increase in accounts payable and accrued expenses of more than $108.5 million in 2005 compared to a decrease of $6.8 million in 2004. In addition, we received $14.7 million during the second quarter of 2005 related to payment of receivables for settled audit years from the Internal Revenue Service.

Cash provided by operating activities declined in 2004 as compared to 2003 primarily as a result of increased investment in working capital. Trade accounts receivable represented the largest use of funds, increasing by more than $31.5 million (net of amounts acquired in business combinations) in 2004. The increase in trade accounts receivables in 2004 resulted from higher sales levels during the period, as revenues increased approximately 33% in 2004 as compared to 2003. Additionally, inventory increased by more than $12.0 million (net of amounts acquired in business combinations) in 2004. Continued rail difficulties resulted in missed shipments and caused the increase in inventory in 2004.

Cash used in investing activities in 2005 was $305.8 million lower than in 2004, due to acquisitions in July 2004 of the 35% of the Canyon Fuel common stock not previously owned by us and the North Rochelle operations from Triton in August 2004, offset by partially higher capital expenditures and payments to affiliates and to purchase equity investments of $23.3 million in 2005. Offsetting uses of cash were proceeds from the sales of land and equipment were $117.0 million, including $84.6 million related to the sale of the Powder River Basin assets discussed in “Results of Operations”, compared to $7.4 million in 2004. In 2004, proceeds of $111.4 million were received from the sale of limited partnership units in Natural Resource Partners L.P.

Capital expenditures of $357.1 million in 2005 increased $64.5 million, fueled by increases in capital spending at the Central Appalachia operations of approximately $150.1 million, offset by a decrease in payments made on a federal coal lease known as Little Thunder discussed below. The increase in Central Appalachia operations includes the development and construction of the Mountain Laurel mining complex, where expenditures of $88.3 million in 2005 represented an increase of approximately $83.0 million over 2004. We financed the Canyon Fuel acquisition with a $22.0 million five-year note and approximately $90.0 million of cash on hand. We financed the Triton acquisition with borrowings under the revolving credit facility of $22.0 million, a term loan in the amount of $100.0 million, and with cash on hand.

Cash provided by investing activities in 2003 reflects the receipt of $115.0 million from the sale of the subordinated units and general partner interest of Natural Resource Partners L.P. and the receipt of $52.5 million from the buyout of a coal supply contract with above-market pricing. These non-recurring cash inflows offset our capital expenditures and advance royalty payments which totaled $165.0 million.

Capital expenditures are made to improve and replace existing mining equipment, expand existing mines, develop new mines and improve the overall efficiency of mining operations. We anticipate that capital expenditures during 2006 will range from $525 to $575 million. This estimate includes capital expenditures related to development work at certain of our mining operations, including the Mountain Laurel complex in West Virginia and the North Lease mine in Utah formerly known as Skyline and our second $122.2 million installment for the Little Thunder coal lease. Also, this estimate assumes no other acquisitions, significant expansions of our existing mining operations or additions to our reserve base. We anticipate that we will fund these capital expenditures with available cash, existing credit facilities and cash generated from operations.

On September 22, 2004, the Bureau of Land Management accepted our bid of $611.0 million for a 5,084-acre federal coal lease known as Little Thunder, which is adjacent to our Black Thunder mine in the Powder River Basin. According to the BLM, the lease contains approximately 719.0 million mineable tons of compliance coal. We paid the first of five annual payments at the time of the bid. We will make the remaining four annual lease payments in fiscal years 2006 through 2009.

Cash used in financing activities during 2005 consists primarily of net payments on our revolving credit facility of $25.0 million, net payments on our long-term debt of $2.4 million and dividend payments of $27.6 million, offset partially by $31.9 million in proceeds from the issuance of common stock under our employee stock incentive plan. Cash provided by financing activities in 2004 consists primarily of proceeds from the issuance of senior notes of $261.9 million and proceeds from the issuance of common stock through a public offering of $230.5 million described below. Additionally, financing activities in 2004 also include net borrowings under our revolving credit facility of $25.0 million, proceeds of $37.0 million from the issuance of common stock under our employee stock incentive plan and dividend payments of $24.0 million. Cash provided by financing activities in 2003 reflects the proceeds from the issuance of the Arch Western Finance senior notes (which were used to retire Arch Western's existing bank debt) and the proceeds from the sale of preferred stock described below.

On January 31, 2003, we completed a public offering of 2,875,000 shares of 5% Perpetual Cumulative Convertible Preferred Stock. The net proceeds from the offering of approximately $139.0 million were used to reduce indebtedness under our revolving credit facility and for working capital and general corporate purposes, including potential acquisitions.

On June 25, 2003, Arch Western Finance, LLC, a subsidiary of Arch Western, completed the offering of $700 million of 6$^3/_4$% senior notes due 2013. We used the proceeds of the offering primarily to repay Arch Western's existing term loans. Interest on the senior notes is payable on January 1 and July 1 each year commencing January 1, 2004. The senior notes are guaranteed by Arch Western and certain of Arch Western's subsidiaries and are secured by a security interest in promissory notes we issued to Arch Western evidencing cash loaned to us by Arch Western. The terms of the senior notes contain restrictive covenants that limit Arch Western's ability to, among other things, incur additional debt, sell or transfer assets, and make investments.

On October 22, 2004, two subsidiaries of Arch Western, as co-obligors, issued $250 million of 6$^3/_4$% senior notes due 2013 at a price of 104.75% of par. The net proceeds of the offering were used to repay and retire the outstanding indebtedness under Arch Western's $100.0 million term loan maturing in 2007, to repay indebtedness under our revolving credit facility and for general corporate purposes.

On October 28, 2004, we completed a public offering of 7,187,500 shares of our common stock, including the underwriters' full over-allotment option, at a price of $33.85 per share. We used the net proceeds of the offering, totaling $230.5 million after the underwriters' discount and expenses, to repay borrowings under our revolving credit facility incurred to finance our acquisition of Triton Coal Company and the first annual payment for the Little Thunder federal coal lease. We intend to use the remaining proceeds for general corporate purposes, including the development of the Mountain Laurel longwall mine in Central Appalachia.

We filed a shelf registration statement on Form S-3 with the Securities and Exchange Commission on November 24, 2004 that allows us to offer and sell from time to time unsecured debt securities consisting of notes, debentures, and other debt securities, common stock, preferred stock, warrants, and/or units totaling a maximum of $1.0 billion. Related proceeds could be used for general corporate purposes including repayment of other debt, capital expenditures, possible acquisitions and any other purposes that may be stated in any prospectus supplement.

We believe that cash generated from operations and our borrowing capacity will be sufficient to meet working capital requirements, anticipated capital expenditures and scheduled debt payments for at least the next several years.

On December 22, 2004, we entered into a $700.0 million revolving credit facility that matures on December 22, 2009. The rate of interest on borrowings under the credit facility is a floating rate based on LIBOR. The credit facility is secured by substantially all of our assets as well as our ownership interests in substantially all of our subsidiaries, except our ownership interests in Arch Western and its subsidiaries. The credit facility replaced our existing $350.0 million revolving credit facility. At December 31, 2005, we had $96.5 million in letters of credit outstanding which, when combined with no outstanding borrowings under the revolver, resulted in $603.5 million of unused borrowings under the revolver. At December 31, 2005, financial covenant requirements do not restrict the amount of unused capacity available to us for borrowing and letters of credit.

Financial covenants contained in our revolving credit facility consist of a maximum leverage ratio, a maximum senior secured leverage ratio and a minimum interest coverage ratio. The leverage ratio requires that we not permit the ratio of total net debt (as defined in the facility) at the end of any calendar quarter to EBITDA (as defined in the facility) for the four quarters then ended to exceed a specified amount. The interest coverage ratio requires that we not permit the ratio of EBITDA (as defined) at the end of any calendar quarter to interest expense for the four quarters then ended to be less than a specified amount. The senior secured leverage ratio requires that we not permit the ratio of total net senior secured debt (as defined) at the end of any calendar quarter to EBITDA (as defined) for the four quarters then ended to exceed a specified amount. We were in compliance with all financial covenants at December 31, 2005.

At December 31, 2005, debt amounted to $982.4 million, or 45% of capital employed, compared to $1,011.1 million, or 48% of capital employed at December 31, 2004. Based on the level of consolidated indebtedness and prevailing interest rates at December 31, 2005, debt service obligations, which include the current maturities of debt and interest expense for 2006, are estimated to be $85.8 million.

We periodically establish uncommitted lines of credit with banks. These agreements generally provide for short-term borrowings at market rates. At December 31, 2005, there were $20 million of such agreements in effect, of which none were outstanding.

On February 10, 2006, we established a $100 million receivables securitization program which expires on February 3, 2011. Pursuant to the program, we may sell, up to $100 million of eligible trade receivables, which have been contributed to our wholly-owned, bankruptcy-remote subsidiary, to a multi-seller, asset-backed commercial paper conduit, on a revolving basis and without recourse.

Under the terms of the program, eligible trade receivables consist of trade receivables generated by our operating subsidiaries. Although the participants in the program bear the risk of non-payment of purchased receivables, we have agreed to indemnify the participants with respect to various matters, and we may be required to repurchase receivables which do not comply with the requirements of the program. The participants under the program will be entitled to receive payments reflecting a specified discount on amounts funded under the program, including drawings under letters of credit, calculated on the basis of the base rate or commercial paper rate, as applicable. We will pay facility fees, program fees and letter of credit fees (based on amounts of outstanding letters of credit) at rates that vary with our debt ratings.

Under the program, we are subject to certain affirmative, negative and financial covenants customary for financings of this type, including restrictions related to, among other things, liens, payments, merger or consolidation and amendments to the agreements underlying the receivables pool. The administrator may terminate the program upon the occurrence of certain events that are customary for facilities of this type (with customary grace periods, if applicable), including, among other things, breaches of covenants, inaccuracies of representations and warranties, bankruptcy and insolvency events, changes in the rate of default or delinquency of the receivables above specified levels, a change of control and material judgments. A termination event would permit the administrator to terminate the program and enforce any and all rights, subject to cure provisions, where, applicable. Additionally, the program contains cross-default provisions, which would allow the administrator to terminate the program in the event of non-payment of other material indebtedness when due, and any other event which results in the acceleration of the maturity of material indebtedness.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At December 31, 2005, substantially all of our outstanding debt bore interest at fixed rates.

We are exposed to price risk related to the value of sulfur dioxide emission allowances that are a component of the quality adjustment provisions in many of our coal supply contracts. We have purchased put options and entered into swap contracts to reduce volatility in the price of sulfur dioxide emission allowances. These contracts serve to protect us from any possible downturn in the price of sulfur dioxide emission allowances. The put option agreements grant us the right to sell a certain quantity of sulfur dioxide emission allowances at a specified price on a specified date. The swap agreements essentially fix the price we receive for sulfur dioxide emission allowances by allowing us to receive a fixed sulfur dioxide allowance price and pay a floating sulfur dioxide allowance price.

We are also exposed to the risk of fluctuations in cash flows related to our purchase of diesel fuel. We enter into forward physical purchase contracts and heating oil swaps and options to reduce volatility in the price of diesel fuel for our operations. The swap agreements essentially fix the price paid for diesel fuel by requiring us to pay a fixed heating oil price and receive a floating heating oil price. The call options protect against increases in diesel fuel by granting us the right to participate in increases in heating oil prices. The changes in the floating heating oil price highly correlate to changes in diesel fuel prices. Accordingly, the derivatives qualify for hedge accounting and the asset of $8.7 million representing the fair value of the derivatives is recorded through other comprehensive income.

In the past, we have utilized interest rate swap agreements to modify the interest characteristics of our outstanding debt, including amounts due under the Arch Western term loans. The swap agreements essentially convert variable-rate debt to fixed-rate debt. These agreements required the exchange of amounts based on variable interest rates for amounts based on fixed interest rates over the life of the agreement. We terminated these swaps in the fourth quarter of 2005.

The discussion below presents the sensitivity of the market value of our financial instruments to selected changes in market rates and prices. The range of changes reflects our view of changes that are reasonably possible over a one-year period. Market values are the present value of projected future cash flows based on the market rates and prices chosen. The major accounting policies for these instruments are described in Note 1 to our consolidated financial statements.

With respect to our sulfur dioxide emission allowance put option and swap positions, as well as our heating oil swap positions, a change in price of the underlying products impacts our net financial instrument position. At December 31, 2005, a $100 decrease in the price of sulfur dioxide emission allowances would result in a $1.3 million increase in the fair value of the financial position of our sulfur dioxide emission allowance put option and swap agreements. At December 31, 2005, a $0.05 per gallon increase in the price of heating oil would result in a $1.6 million increase in the fair value of the financial position of our heating oil swap agreements.

Contractual Obligations

The following is a summary of our significant contractual obligations as of December 31, 2005:

	Payments Due by Period			
	2006	2007-2008	2009-2010	After 2010
	(Amounts in thousands)			
Long-term debt, including related interest	$ 10,649	$ 7,277	$ 4,347	$ 960,246
Operating leases	24,089	43,402	30,078	42,078
Royalty leases	148,590	171,135	168,927	44,742
Unconditional purchase obligations	582,664	83,525	113	—
Total contractual obligations	$ 765,992	$ 305,339	$ 203,465	$ 1,047,066

Royalty leases represent non-cancelable royalty lease agreements as well as federal lease bonus payments due under the Little Thunder lease. Remaining payments due under the Little Thunder lease will be paid in four equal annual installments of $122.2 million in fiscal years 2006 through 2009. Unconditional purchase obligations represent amounts committed for purchases of materials and supplies, payments for services, purchased coal, and capital expenditures.

We currently anticipate making contributions of approximately $21.0 million to the pension plan in 2006.

We believe that our on-hand cash balance, cash generated from operations, and borrowing capacity under our revolving credit facility and other debt facilities will be sufficient to meet these obligations and our requirements for working capital and capital expenditures.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include guarantees, indemnifications, financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

We use a combination of surety bonds, corporate guarantees (i.e. self bonds) and letters of credit to secure our financial obligations for reclamation, workers' compensation, postretirement benefits, coal lease obligations and other obligations as follows as of December 31, 2005 (dollars in millions):

	Reclamation Obligations	Lease Obligations	Workers' Compensation Obligations	Retiree Healthcare Obligations	Other	Total
Self bonding	$ 229.9	$ —	$ —	$ —	$ —	$ 229.9
Surety bonds	238.7	33.9	14.7	—	136.2	423.5
Letters of credit	11.3	—	45.1	27.5	13.8	97.7

In accordance with the purchase and sale agreement with Magnum Coal, we have agreed to continue to provide surety bonds and letters of credit for reclamation and workers' compensation obligations of Magnum related to the properties sold by us to them in order to facilitate an orderly transition. The purchase and sale agreement requires Magnum to reimburse us for costs related to the surety bonds and letters of credit and to use commercially reasonable efforts after closing to replace the obligations. If the surety bonds and letters of credit related to the reclamation obligations are not replaced by Magnum within two years of closing of the transaction, then Magnum will post a letter of credit in favor of us in the amounts of the obligations. If letter of credit related to the workers' compensation obligation is not replaced within 360 days following the closing of the transaction, Magnum shall post a letter of credit in favor of us in the amounts of the obligation. Of the surety bonds related to reclamation obligations, $92.8 million relate to properties sold to Magnum while $10.5 million of letters of credit related to the retiree healthcare obligation relates to the properties sold to Magnum.

In addition, we have agreed to guarantee the performance of Magnum with respect to three coal sales contracts and several property leases we sold to Magnum. If Magnum is unable to perform with respect to the coal sales contracts, we would be required to purchase coal on the open market or supply the contract from our existing operations. If we purchased all of the coal for these contracts at today's market prices, we would incur a loss of approximately $654.0 million related to the contracts. If Magnum is unable to perform with respect to the property leases, we would be responsible for future minimum royalty payments of approximately $12.4 million. We believe it is remote we would be liable for any obligation related to these guarantees.

In connection with our June 1, 1998 acquisition of Atlantic Richfield Company's coal operations, we entered into an agreement under which we agreed to indemnify Atlantic Richfield against specified tax liabilities in the event that these liabilities arise prior to June 1, 2013 as a result of certain actions taken, including the sale or other disposition of certain properties of Arch Western, the repurchase of certain equity interests in Arch Western by Arch Western, or the reduction under certain circumstances of indebtedness incurred by Arch Western in connection with the acquisition. Atlantic Richfield was acquired by BP p.l.c. in 2000. If such indemnification obligation were to arise, it could potentially have a material adverse effect on our business, results of operations and financial condition.

In addition, tax reporting applied to this transaction by the other member of Arch Western is under review by the IRS. We do not believe it is probable that we will be impacted by the outcome of this review. If the outcome of this review results in adjustments, we may be required to adjust our deferred income taxes associated with our investment in Arch Western. Given the uncertainty of an adverse outcome impacting our deferred income tax position as well as offsetting tax positions we may be able to take, we are not able to determine a range of the potential outcomes related to this issue. Any change that impacts us related to the IRS review of the other member of this transaction potentially could have a material adverse impact on our financial statements.

You should also see Note 20 to our consolidated financial statements for more information about our guarantee and indemnification obligations.

Contingencies

Reclamation. The Federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes require that mine property be restored in accordance with specified standards and an approved reclamation plan. We accrue for the costs of reclamation in accordance with the provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," which we refer to as FAS 143, adopted as of January 1, 2003. These costs relate to reclaiming the pit and support acreage at surface mines and sealing portals at deep mines. Other costs of reclamation common to surface and underground mining are related to reclaiming refuse and slurry ponds, eliminating sedimentation and drainage control structures, and dismantling or demolishing equipment or buildings used in mining operations. The establishment of the asset retirement obligation liability is based upon permit requirements and requires various estimates and assumptions, principally associated with costs and productivities.

We review our entire environmental liability periodically and make necessary adjustments, including permit changes and revisions to costs and productivities to reflect current experience. Our management believes it is making adequate provisions for all expected reclamation and other associated costs.

Permit Litigation Matters. A group of local and national environmental organizations filed suit against the U.S. Army Corps of Engineers in the U.S. District Court in Huntington, West Virginia on October 23, 2003. In its complaint, *Ohio River Valley Environmental Coalition, et al v. Bulen, et al*, the plaintiffs allege that the Corps has violated its statutory duties arising under the Clean Water Act, the Administrative Procedure Act and the National Environmental Policy Act in issuing the Nationwide 21 general permit. The plaintiffs allege that the procedural requirements of the three federal statutes identified in their complaint have been violated, and that the Corps may not utilize the mechanism of a nationwide permit to authorize valley fills. If the plaintiffs prevail in this litigation, it may delay our receipt of these permits.

On July 8, 2004, the District Court entered a final order enjoining the Corps from authorizing new valley fills using the mechanism of its nationwide permit. The District Court modified its earlier decision on August 13, 2004, when it directed the Corps to suspend all permits for fills that had not commenced construction as of July 8, 2004.

Three permits issued at two of our operating subsidiaries were affected by the Court’s order. Although the two operating subsidiaries were prohibited from constructing the fills previously authorized, the Court’s order did allow them to permit the fill construction using the mechanism of an individual section 404 Clean Water Act permit. We do not believe that obtaining an individual permit will adversely impact either of the operating subsidiaries.

The Corps and five intervening trade associations, three of which we are a member, filed an appeal with the U.S. Court of Appeals for the Fourth Circuit in this matter on September 16, 2004. The matter was briefed and argued before the Fourth Circuit on September 19, 2005. On November 23, 2005, the Fourth Circuit reversed the District Court’s decision but remanded the case for decision on the Clean Water Act, the Administrative Procedure Act and the National Environmental Policy Act claims not addressed by the District Court in its initial decision. The plaintiffs filed a petition for rehearing by the Fourth Circuit. On February 15, 2006, the Fourth Circuit rejected the plantiff’s request for rehearing. The Fourth Circuit’s ruling technically re-instates its nationwide permit in the Southern District of West Virginia.

While the outcome of this litigation is subject to uncertainties, based on our preliminary evaluation of the issues and the potential impact on us, we believe this matter will be resolved without a material adverse effect on our financial condition or results of operations or liquidity.

West Virginia Flooding Litigation. We and three of our subsidiaries have been served, among others, in seventeen separate complaints filed and served in Wyoming, McDowell, Fayette, Kanawha, Raleigh, Boone and Mercer Counties, West Virginia. These cases collectively include approximately 3,100 plaintiffs who are seeking to recover from more than 180 defendants for property damage and personal injuries arising out of flooding that occurred in southern West Virginia on or about July 8, 2001. The plaintiffs have sued coal, timber, oil and gas, and land companies under the theory that mining, construction of haul roads and removal of timber caused natural surface waters to be diverted in an unnatural way, thereby causing damage to the plaintiffs. The West Virginia Supreme Court has ruled that these cases, along with thirty-seven other flood damages cases not involving our subsidiaries, be handled pursuant to the Court's Mass Litigation rules. As a result of this ruling, the cases have been transferred to the Circuit Court of Raleigh County in West Virginia to be handled by a panel consisting of three circuit court judges, which certified certain legal issues back to the West Virginia Supreme Court. The West Virginia Supreme Court responded to the questions certified, and discovery is underway. Trials, by watershed, are expected to begin this year and will proceed in phases.

While the outcome of this litigation is subject to uncertainties, based on our preliminary evaluation of the issues and the potential impact on us, we believe this matter will be resolved without a material adverse effect on our financial condition or results of operations or liquidity.

Ark Land Company v. Crown Industries. In response to a declaratory judgment action filed by Ark Land Company, a subsidiary of ours, in Mingo County, West Virginia, against Crown Industries involving the interpretation of a severance deed under which Ark Land controls the coal and mining rights on property in Mingo County, West Virginia, Crown Industries filed a counterclaim against Ark Land and a third party complaint against us and two of our other subsidiaries seeking damages for trespass, nuisance and property damage arising out of the exercise of rights under the severance deed on the property by our subsidiaries. The defendant alleged that our subsidiaries had insufficient rights to haul certain foreign coals across the property without payment of certain wheelage or other fees to the defendant. In addition, the defendant alleged that we and our subsidiaries violated West Virginia's Standards for Management of Waste Oil and the West Virginia Surface Coal Mining and Reclamation Act. This case went to trial on October 4, 2005. Crown Industries' counterclaim against Ark Land was dismissed along with its cross claim against one of our subsidiaries and its claims for trespass, nuisance and wheelage. On October 12, 2005, the jury entered a verdict in favor of Crown Industries on its remaining claims, assessing damages against us and our subsidiary in the amount of $2.5 million. The jury found in our favor on our indemnity claim against our subsidiary's contractor, and awarded us $1.25 million on that claim. Crown Industries also was awarded its reasonable attorneys' fees, which had not yet been determined. We have reached a settlement in principle with Crown Industries.

Shonk Land Company v. Ark Land Company. Shonk Land Company leases certain West Virginia real estate to our subsidiary Ark Land Company in exchange for royalties on coal mined from it. Shonk Land Company filed a lawsuit in the Circuit Court for Kanawha County, West Virginia, claiming, among other things, that Ark Land Company misrepresented certain facts involving a lease amendment and that it miscalculated and underpaid royalties under the lease. Shonk Land Company sought damages of approximately $14.5 million. Ark Land disputed its claims and filed a counterclaim for overpayment of royalties in the approximate amount of $260,000. The court directed the parties to arbitrate their dispute in accordance with the terms of their lease. The arbitration began on October 31, 2005, but the parties reached a settlement before the arbitrators decided the case.

We are a party to numerous other claims and lawsuits and are subject to numerous other contingencies with respect to various matters. We provide for costs related to contingencies, including environmental, legal and indemnification matters, when a loss is probable and the amount is reasonably determinable. After conferring with counsel, it is the opinion of management that the ultimate resolution of these claims, to the extent not previously provided for, will not have a material adverse effect on our consolidated financial condition, results of operations or liquidity.

Critical Accounting Policies

We prepare our financial statements in accordance with accounting principles that are generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities. Management bases its estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Additionally, these estimates and judgments are discussed with our Audit Committee on a periodic basis. Actual results may differ from the estimates used under different assumptions or conditions. Note 1 to our consolidated financial statements provides a description of all significant accounting policies. We believe that of these significant accounting policies, the following may involve a higher degree of judgment or complexity:

Asset Retirement Obligations

Our asset retirement obligations arise from the federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. Significant reclamation activities include reclaiming refuse and slurry ponds, reclaiming the pit and support acreage at surface mines, and sealing portals at deep mines. We account for the costs of our reclamation activities in accordance with the provisions of FAS 143. We determine the future cash flows necessary to satisfy our reclamation obligations on a mine-by-mine basis based upon current permit requirements and various estimates and assumptions, including estimates of disturbed acreage, cost estimates, and assumptions regarding productivity. We determine estimates of disturbed acreage based on approved mining plans and related engineering data. We base our cost estimates on historical internal or third-party costs depending on how we expect to perform the work. We base productivity assumptions on historical experience with the equipment that we expect to utilize in the reclamation activities. In accordance with the provisions of FAS 143, we determine the fair value of our asset retirement obligations. In order to determine fair value, we must also estimate a discount rate and third-party margin. Each estimate is discussed in further detail below:

- *Discount rate* — FAS 143 requires that asset retirement obligations be recorded at fair value. In accordance with the provisions of FAS 143, we utilize discounted cash flow techniques to estimate the fair value of our obligations. We base our discount rate on the rates of treasury bonds with maturities similar to expected mine lives, adjusted for our credit standing.

- *Third-party margin* — FAS 143 requires the measurement of an obligation to be based upon the amount a third-party would demand to assume the obligation. Because we plan to perform a significant amount of the reclamation activities with internal resources, we add a third-party margin to the estimated costs of these activities. We estimate this margin based on our historical experience with contractors performing certain types of reclamation activities. The inclusion of this margin results in a recorded obligation that exceeds our estimated cost to perform the reclamation activities with internal resources.

If our cost estimates are accurate, we record the excess of the recorded obligation over the cost incurred to perform the work as a gain at the time that we complete the reclamation work.

On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, additional costs resulting from accelerated mine closures, and revisions to cost estimates and productivity assumptions, to reflect current experience. At December 31, 2005, we had recorded asset retirement obligation liabilities of $177.4 million, including amounts reported as current. While the precise amount of these future costs cannot be determined with certainty, as of December 31, 2005, we estimate that the aggregate undiscounted cost of final mine closure is approximately $385.2 million.

Derivative Financial Instruments

Derivative financial instruments are accounted for in accordance with Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, which we refer to as FAS 133. FAS 133 requires all derivative financial instruments to be reported on the balance sheet at fair value. Changes in fair value are recognized either in earnings or equity, depending on whether the transaction qualifies for hedge accounting, and if so, the nature of the underlying exposure being hedged and how effective the derivatives are at offsetting price movements in the underlying exposure.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking various hedge transactions. We evaluate the effectiveness of our hedging relationships both at the hedge inception and on an ongoing basis. Any ineffectiveness is recorded in the Consolidated Statements of Income.

Employee Benefit Plans

We have non-contributory defined benefit pension plans covering certain of our salaried and non-union hourly employees. Benefits are generally based on the employee’s age and compensation. We fund the plans in an amount not less than the minimum statutory funding requirements nor more than the maximum amount that can be deducted for federal income tax purposes. We contributed $20.0 million in cash and stock to the plan during the year ended December 31, 2005 and $21.6 million during the year ended December 31, 2004. We account for our defined benefit plans in accordance with Statement of Financial Accounting Standards No. 87, “Employer’s Accounting for Pensions,” which requires amounts recognized in the financial statements to be determined on an actuarial basis.

The calculation of our net periodic benefit costs (pension expense) and benefit obligation (pension liability) associated with our defined benefit pension plans requires the use of a number of assumptions that we deem to be “critical accounting estimates.” Changes in these assumptions can result in different pension expense and liability amounts, and actual experience can differ from the assumptions.

- The expected long-term rate of return on plan assets is an assumption reflecting the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. We establish the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The pension plan’s investment targets are 65% equity, 30% fixed income securities and 5% cash. Investments are rebalanced on a periodic basis to stay within these targeted guidelines. The long-term rate of return assumption used to determine pension expense was 8.5% for each of the years ended December 31, 2005 and 2004. These long-term rate of return assumptions are less than the plan's actual life-to-date returns. Any difference between the actual experience and the assumed experience is deferred as an unrecognized actuarial gain or loss and amortized into the future. The impact of lowering the expected long-term rate of return on plan assets from 8.5% to 8.0% for 2005 would have been an increase in expense of approximately $0.9 million.

- The discount rate represents our estimate of the interest rate at which pension benefits could be effectively settled. Assumed discount rates are used in the measurement of the projected, accumulated and vested benefit obligations and the service and interest cost components of the net periodic pension cost. In estimating that rate, Statement No. 87 requires rates of return on high quality, fixed income investments. We utilize a bond portfolio model that includes bonds that are rated "AA" or higher with maturities that match the expected benefit payments under the plan. The discount rates used to determine pension expense was 6.0% for 2005 and 6.5% for 2004. The impact of lowering the discount rate from 6.0% to 5.5% in 2005 would have been an increase in expense of approximately $1.7 million.

The differences generated in changes in assumed discount rates and returns on plan assets are amortized into earnings over a five-year period.

For the measurement of our year-end pension obligation for 2005 (and pension expense for 2006), we decreased our long-term rate of return assumption from 8.5% to 8.25% and changed our discount rate to 5.8%.

We also currently provide certain postretirement medical/life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement medical/life plans are contributory, with retiree contributions adjusted periodically, and contain other cost-sharing features such as deductibles and coinsurance. The postretirement medical plan for retirees who were members of the United Mine Workers of America is not contributory. Our current funding policy is to fund the cost of all postretirement medical/life insurance benefits as they are paid. We account for our other postretirement benefits in accordance with Statement of Financial Accounting Standards No. 106, "Employer's Accounting for Postretirement Benefits Other Than Pensions," which requires amounts recognized in the financial statements to be determined on an actuarial basis.

The disposition of the Central Appalachia operations to Magnum constituted a settlement of our postretirement benefit obligation for which we recognized a loss of $59.2 million. The only remaining participants in the postretirement benefit plan have their benefits capped at current levels.

Various actuarial assumptions are required to determine the amounts reported as obligations and costs related to the postretirement benefit plan. These assumptions include the discount rate and the future medical cost trend rate.

- The discount rate assumption reflects the rates available on high-quality fixed-income debt instruments at year-end and is calculated in the same manner as discussed above for the pension plan. The discount rate used to calculate the postretirement benefit expense was 6.0% for 2005 and 6.5% for 2004. Had the discount rate been lowered from 6.0% to 5.5% in 2005, we would have incurred additional expense of $1.7 million.

- Future medical trend rate represents the rate at which medical costs are expected to increase over the life of the plan. The health care cost trend rate is determined based upon our historical changes in health care costs as well as external data regarding such costs. We have implemented many effective programs that have resulted in actual increases in medical costs to fall far below the double-digit increases experienced by most companies in recent years. The postretirement expense in 2005 was based on an assumed medical inflationary rate of 8.0%, trending down in half percent increments to 5%, which represents the ultimate inflationary rate for the remainder of the plan life. This assumption was based on our then current three-year historical average of per capita increases in health care costs. If we had utilized a medical trend rate that is 1% higher, we would have incurred $4.0 million of additional expense in 2005.

For the measurement of our year-end other postretirement obligation for 2005 and postretirement expense for 2006, we changed our discount rate to 5.8%. Because postretirement costs for remaining participants are capped at current levels, future changes in health care costs have no future effect on the plan benefits.

Income Taxes

We record deferred tax assets and liabilities using enacted tax rates for the effect of temporary differences between the book and tax bases of assets and liabilities. A valuation allowance is recorded to reflect the amount of future tax benefits that management believes are not likely to be realized. In determining the appropriate valuation allowance, we take into account the level of expected future taxable income and available tax planning strategies. If future taxable income was lower than expected or if expected tax planning strategies were not available as anticipated, we may record additional valuation allowance through income tax expense in the period such determination was made.

Accounting Standards Issued and Not Yet Adopted

In November 2004, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 151, Inventory Costs, an amendment of ARB No. 43, Chapter 4. This statement amends the guidance in ARB No. 43, Chapter 4, “Inventory Pricing,” to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs, and wasted material (spoilage). Provisions of this statement are effective for fiscal years beginning after June 15, 2005. We do not expect the adoption of this statement to have a material impact on our financial statements.

In December 2004, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment, which we refer to as FAS 123R. FAS 123R requires all public companies to measure compensation cost in the income statement for all share-based payments (including employee stock options) at fair value for interim and annual periods. On April 14, 2005, the Securities and Exchange Commission delayed the implementation of FAS 123R from its original implementation date by six months for most registrants, requiring all public companies to adopt FAS 123R no later than the beginning of the first fiscal year beginning after June 15, 2005. We adopted FAS 123R on January 1, 2006 using the modified-prospective method. Under this method, companies are required to recognize compensation cost for share-based payments to employees based on their grant-date fair value from the beginning of the fiscal period in which the recognition provisions are first applied. Measurement and recognition of compensation cost for awards that were granted prior to, but not vested as of, the date FAS 123R is adopted would be based on the same estimate of the grant-date fair value and the same recognition method used previously under FAS 123. FAS 123R also requires the benefits of tax deductions in excess of recognized compensation cost to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after adoption. We do not expect the effect of the adoption of FAS 123R to be significant.

On March 30, 2005, the Financial Accounting Standards Board ratified the consensus reached by the Emerging Issues Task Force on issue No. 04-6, Accounting for Stripping Costs in the Mining Industry. This issue applies to stripping costs incurred in the production phase of a mine for the removal of overburden or waste materials for the purpose of obtaining access to coal that will be extracted. Under the issue, stripping costs incurred during the production phase of the mine are variable production costs that are included in the cost of inventory produced and extracted during the period the stripping costs are incurred. Historically, we have associated stripping costs at our surface mining operations with the cost of tons of coal uncovered and have classified tons uncovered but not yet extracted as coal inventory. The guidance in this issue is effective for fiscal years beginning after December 15, 2005 for which the cumulative effect of adoption should be recognized as an adjustment to the beginning balance of retained earnings during the period. We adopted the change on January 1, 2006 and, accordingly, recognized an adjustment to the beginning balance of retained earnings of $40.7 million.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements of Arch Coal, Inc. and subsidiaries and reports of independent registered public accounting firm follow.

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Arch Coal, Inc.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Arch Coal, Inc. maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Arch Coal Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Arch Coal, Inc. maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion Arch Coal, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Arch Coal, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005 of Arch Coal, Inc. and our report dated March 1, 2006 expressed an unqualified opinion thereon.

Ernst + Young LLP

Ernst & Young LLP

St. Louis, Missouri
March 1, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Arch Coal, Inc.

We have audited the accompanying consolidated balance sheets of Arch Coal, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Arch Coal, Inc. and subsidiaries at December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Arch Coal, Inc.'s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2006 expressed an unqualified opinion thereon.

Ernst + Young LLP

Ernst & Young LLP

St. Louis, Missouri
March 1, 2006

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, our management concluded that our internal control over financial reporting is effective as of December 31, 2005.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

Steven F. Leer
Steven F. Leer
President and Chief
Executive Officer

Robert J. Messey
Robert J. Messey
Senior Vice President and Chief
Financial Officer

REPORT OF MANAGEMENT

The management of Arch Coal, Inc. is responsible for the preparation of the consolidated financial statements and related financial information in this annual report. The financial statements are prepared in accordance with accounting principles generally accepted in the United States and necessarily include some amounts that are based on management's informed estimates and judgments, with appropriate consideration given to materiality.

The Company maintains a system of internal accounting controls designed to provide reasonable assurance that financial records are reliable for purposes of preparing financial statements and that assets are properly accounted for and safeguarded. The concept of reasonable assurance is based on the recognition that the cost of a system of internal accounting controls should not exceed the value of the benefits derived. The Company has a professional staff of internal auditors who monitor compliance with and assess the effectiveness of the system of internal accounting controls.

The Audit Committee of the Board of Directors, composed of directors who are free from relationships that may impair their independence from Arch Coal, Inc., meets regularly with management, the internal auditors, and the independent auditors to discuss matters relating to financial reporting, internal accounting control, and the nature, extent and results of the audit effort. The independent auditors and internal auditors have full and free access to the Audit Committee, with and without management present.

Steven F. Leer
President and Chief
Executive Officer

Robert J. Messey
Senior Vice President and Chief
Financial Officer

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2005	2004	2003
	(In thousands of dollars except per share data)		
REVENUES			
Coal sales	$ 2,508,773	$ 1,907,168	$ 1,435,488
COSTS AND EXPENSES			
Cost of coal sales	2,174,007	1,638,646	1,280,608
Depreciation, depletion and amortization	212,301	166,322	158,464
Selling, general and administrative expenses	91,568	57,975	60,159
Other expenses	80,983	35,758	18,245
	2,558,859	1,898,701	1,517,476
OTHER OPERATING INCOME			
Gain on sale of units of Natural Resource Partners, LP	—	91,268	42,743
Gain on sale of Powder River Basin assets	46,547	—	—
Gain on sale of Central Appalachian operations	7,528	—	—
Income from equity investments	—	10,828	34,390
Other operating income	73,868	67,483	45,226
	127,943	169,579	122,359
Income from operations	77,857	178,046	40,371
Interest expense, net:			
Interest expense	(72,409)	(62,634)	(50,133)
Interest income	9,289	6,130	2,636
	(63,120)	(56,504)	(47,497)
Other non-operating income (expense):			
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	(7,740)	(9,010)	(8,955)
Other non-operating income (expense)	(3,524)	1,044	13,211
	(11,264)	(7,966)	4,256
Income (loss) before income taxes and cumulative effect of accounting change	3,473	113,576	(2,870)
Benefit from income taxes	(34,650)	(130)	(23,210)
Income before cumulative effect of accounting change	38,123	113,706	20,340
Cumulative effect of accounting change, net of taxes	—	—	(3,654)
NET INCOME	$ 38,123	$ 113,706	$ 16,686
Preferred stock dividends	(15,579)	(7,187)	(6,589)
Net income available to common shareholders	$ 22,544	$ 106,519	$ 10,097
EARNINGS PER COMMON SHARE			
Basic earnings per common share before cumulative effect of accounting change	$ 0.35	$ 1.91	$ 0.26
Cumulative effect of accounting change	—	—	(0.07)
Basic earnings per common share	$ 0.35	$ 1.91	$ 0.19
Diluted earnings per common share before cumulative effect of accounting change	$ 0.35	$ 1.78	$ 0.26
Cumulative effect of accounting change	—	—	(0.07)
Diluted earnings per common share	$ 0.35	$ 1.78	$ 0.19

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	(In thousands of dollars except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 260,501	$ 323,167
Trade accounts receivable	179,220	180,902
Other receivables	40,384	34,407
Inventories	130,720	119,893
Prepaid royalties	2,000	12,995
Deferred income taxes	88,461	33,933
Other	28,278	25,560
Total current assets	729,564	730,857
Property, plant and equipment		
Coal lands and mineral rights	1,475,429	1,725,339
Plant and equipment	1,270,775	1,423,550
Deferred mine development	417,879	408,657
	3,164,083	3,557,546
Less accumulated depreciation, depletion and amortization	(1,334,457)	(1,524,346)
Property, plant and equipment, net	1,829,626	2,033,200
Other assets		
Prepaid royalties	106,393	87,285
Goodwill	40,032	37,381
Deferred income taxes	223,856	241,226
Other	121,969	126,586
Total other assets	492,250	492,478
Total assets	$ 3,051,440	$ 3,256,535
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 256,883	$ 148,014
Accrued expenses	245,656	217,216
Current portion of debt	10,649	9,824
Total current liabilities	513,188	375,054
Long-term debt	971,755	1,001,323
Accrued postretirement benefits other than pension	41,326	380,424
Asset retirement obligations	166,728	179,965
Accrued workers' compensation	53,803	82,446
Other noncurrent liabilities	120,399	157,497
Total liabilities	1,867,199	2,176,709
Stockholders' equity		
Preferred stock, $.01 par value, $50 liquidation preference, authorized 10,000,000 shares, issued and outstanding 150,508 and 2,875,000 shares, respectively	2	29
Common stock, $.01 par value, authorized 100,000,000 shares, issued 71,370,684 and 62,857,658 shares, respectively	719	631
Paid-in capital	1,367,470	1,280,513
Retained deficit	(164,181)	(166,273)
Unearned compensation	(9,947)	(1,830)
Less treasury stock, at cost, 84,200 and 357,200 shares, respectively	(1,190)	(5,047)
Accumulated other comprehensive loss	(8,632)	(28,197)
Total stockholders' equity	1,184,241	1,079,826
Total liabilities and stockholders' equity	$ 3,051,440	$ 3,256,535

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Three Years Ended December 31, 2005

	Preferred Stock	Common Stock	Paid-In Capital	Retained Earnings (Deficit)	Unearned Compensation	Treasury Stock at Cost	Accumulated Other Comprehensive Loss	Total
	(In thousands of dollars except share and per share data)							
BALANCE AT JANUARY 1, 2003	$ —	$ 527	$ 835,763	$ (253,943)	$ —	$ (5,047)	$ (42,437)	$ 534,863
Comprehensive income								
Net income				16,686				16,686
Minimum pension liability adjustment							3,403	3,403
Unrealized losses on derivatives							(5,940)	(5,940)
Net amount reclassified to income							4,951	4,951
Total comprehensive income								19,100
Dividends								
Common ($0.23 per share)				(12,090)				(12,090)
Preferred ($2.29 per share)				(6,589)				(6,589)
Issuance of 2,875,000 shares of perpetual cumulative convertible preferred stock	29		138,995					139,024
Issuance of 770,609 shares of common stock under the stock incentive plan, including income tax benefits		9	13,718					13,727
BALANCE AT DECEMBER 31, 2003	29	536	988,476	(255,936)	—	(5,047)	(40,023)	688,035
Comprehensive income								
Net income				113,706				113,706
Minimum pension liability adjustment							1,221	1,221
Unrealized gains on available-for-sale securities							2,081	2,081
Net amount reclassified to income							8,524	8,524
Total comprehensive income								125,532
Dividends								
Common ($0.2975 per share)				(16,856)				(16,856)
Preferred ($2.50 per share)				(7,187)				(7,187)
Issuance of 7,187,500 shares of common stock pursuant to public offering		72	230,455					230,527
Issuance of 500,000 shares of common stock as contribution to pension plan		5	15,435					15,440
Issuance of 149,190 shares of common stock under the stock incentive plan — restricted stock units		1	4,246		(4,247)			—
Expense recognized on restricted stock units					2,417			2,417
Issuance of 1,658,179 shares of common stock under the stock incentive plan — stock options, including income tax benefits		17	41,901					41,918
BALANCE AT DECEMBER 31, 2004	29	631	1,280,513	(166,273)	(1,830)	(5,047)	(28,197)	1,079,826
Comprehensive income								
Net income				38,123				38,123
Minimum pension liability adjustment							(2,751)	(2,751)
Unrealized gains on available-for-sale securities							8,498	8,498
Unrealized losses on derivatives							22,646	22,646
Net amount reclassified to income							(8,828)	(8,828)
Total comprehensive income								57,688
Dividends								
Common ($0.32 per share)				(20,452)				(20,452)
Preferred ($2.50 per share)				(6,053)				(6,053)
Preferred stock conversion	(27)	66	9,487	(9,526)				—
Issuance of 273,000 shares of treasury stock as contribution to pension plan		3	12,872			3,857		16,732
Issuance of 1,518,861 shares of common stock under the stock incentive plan — stock options, including income tax benefits		15	43,564					43,579
Expense recognized on stock incentive plans			140		12,781			12,921
Issuance of 340,046 shares of common stock under the stock incentive plans		4	20,894		(20,898)			—
BALANCE AT DECEMBER 31, 2005	$ 2	$ 719	$ 1,367,470	$ (164,181)	$ (9,947)	$ (1,190)	$ (8,632)	$ 1,184,241

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2005	2004	2003
	(In thousands of dollars)		
OPERATING ACTIVITIES			
Net income	$ 38,123	$ 113,706	$ 16,686
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	212,301	166,322	158,464
Prepaid royalties expensed	14,252	13,889	13,153
Accretion on asset retirement obligations	15,129	12,681	12,999
Gain on sale of units of Natural Resource Partners, LP	—	(91,268)	(42,743)
Net gain on disposition of property, plant and equipment	(82,168)	(6,668)	(3,782)
Income from equity investments	—	(10,828)	(34,390)
Net distributions from equity investments	—	17,678	49,686
Cumulative effect of accounting change	—	—	3,654
Other non-operating expense (income)	11,264	7,966	(4,256)
Changes in operating assets and liabilities (see Note 22)	13,248	(67,406)	(375)
Other	32,458	(7,344)	(6,735)
Cash provided by operating activities	254,607	148,728	162,361
INVESTING ACTIVITIES			
Capital expenditures	(357,142)	(292,605)	(132,427)
Payments for acquisitions, net of cash acquired	—	(387,751)	—
Proceeds from disposition of property, plant and equipment	117,048	7,428	4,282
Proceeds from sale of units of Natural Resource Partners, LP	—	111,447	115,000
Additions to prepaid royalties	(28,164)	(33,813)	(32,571)
Advances to affiliates/purchases of investments	(23,285)	(2,000)	—
Proceeds from coal supply agreements	—	—	52,548
Cash provided by (used in) investing activities	(291,543)	(597,294)	6,832
FINANCING ACTIVITIES			
Net borrowings (payments) on revolver and lines of credit	(25,000)	25,000	(65,971)
Net payments on long-term debt	(2,376)	(302)	(675,000)
Proceeds from issuance of senior notes	—	261,875	700,000
Debt financing costs	(2,662)	(12,806)	(18,508)
Dividends paid	(27,639)	(24,043)	(17,481)
Proceeds from issuance of preferred stock	—	—	139,024
Proceeds from sale of common stock	31,947	267,468	13,727
Cash provided by (used in) financing activities	(25,730)	517,192	75,791
Increase (decrease) in cash and cash equivalents	(62,666)	68,626	244,984
Cash and cash equivalents, beginning of year	323,167	254,541	9,557
Cash and cash equivalents, end of year	$ 260,501	$ 323,167	$ 254,541
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year for interest	$ 69,839	$ 53,558	$ 30,014
Cash paid (received) during the year for income taxes	$ (5,518)	$ 13,350	$ (6,407)

The accompanying notes are an integral part of the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(In Thousands of Dollars Except Per Share Data)

1. Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Arch Coal, Inc. and its subsidiaries and controlled entities (the "Company"). The Company's primary business is the production of steam and metallurgical coal from surface and underground mines throughout the United States, for sale to utility, industrial and export markets. The Company's mines are located in southern West Virginia, eastern Kentucky, Virginia, southern Wyoming, Colorado and Utah. All subsidiaries (except as noted below) are wholly-owned. Intercompany transactions and accounts have been eliminated in consolidation.

The Company owns a 99% ownership interest in a joint venture named Arch Western Resources, LLC ("Arch Western") which operates coal mines in Wyoming, Colorado and Utah. The Company also acts as the managing member of Arch Western.

As of and for the period ended July 31, 2004, the membership interests in the Utah coal operations, Canyon Fuel Company, LLC ("Canyon Fuel"), were owned 65% by Arch Western and 35% by a subsidiary of ITOCHU Corporation. Through July 31, 2004, the Company's 65% ownership of Canyon Fuel was accounted for on the equity method in the Consolidated Financial Statements as a result of certain super-majority voting rights in the joint venture agreement. Income from Canyon Fuel through July 31, 2004 is reflected in the Consolidated Statements of Income as income from equity investments (see additional discussion in Note 5, "Investments"). On July 31, 2004, the Company acquired the remaining 35% of Canyon Fuel. See Note 2, "Business Combinations" for further discussion.

On December 31, 2005, the Company entered into a Purchase and Sale Agreement (the "Purchase Agreement") with Magnum Coal Company ("Magnum"). Pursuant to the Purchase Agreement, the Company sold the stock of four of its active Central Appalachian mining operations. See further discussion in Note 3, "Dispositions."

Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost. Cash equivalents consist of highly-liquid investments with an original maturity of three months or less when purchased.

Allowance for Uncollectible Receivables

The Company maintains allowances to reflect its trade accounts receivable and other receivables which are not expected to be collected, based on past collection history, the economic environment and specified risks identified in the receivables portfolio. Receivables are considered past due if the full payment is not received by the contractual due date. Allowances recorded at December 31, 2005 and 2004 were $1.8 million and $3.0 million, respectively.

Inventories

Inventories consist of the following:

	December 31,	
	2005	2004
Coal	$ 73,284	$ 76,009
Supplies, net of allowance	57,436	43,884
	$ 130,720	$ 119,893

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs and operating overhead. The Company has recorded a valuation allowance for slow-moving and obsolete supplies inventories of $16.1 million and $23.0 million at December 31, 2005 and 2004, respectively.

Investments

Investments and ownership interests are accounted for under the equity method of accounting if the Company has the ability to exercise significant influence, but not control, over the entity. The Company reflects its share of the entity’s income in its Consolidated Statements of Income. Marketable equity securities held by the Company that do not qualify for equity method accounting are classified as available-for-sale and are recorded at their fair value through other comprehensive income.

Prepaid Royalties

Rights to leased coal lands are often acquired through royalty payments. Where royalty payments represent prepayments recoupable against production, they are recorded as a prepaid asset, and amounts expected to be recouped within one year are classified as a current asset. As mining occurs on these leases, the prepayment is charged to cost of coal sales.

Coal Supply Agreements

Acquisition costs allocated to coal supply agreements (sales contracts) are capitalized and amortized on the basis of coal to be shipped over the term of the contract. Value is allocated to coal supply agreements based on discounted cash flows attributable to the difference between the above or below-market contract price and the then-prevailing market price. The net book value of the Company's above-market coal supply agreements was $6.3 million and $11.1 million at December 31, 2005 and 2004, respectively. These amounts are recorded in other assets in the accompanying Consolidated Balance Sheets. The net book value of all below-market coal supply agreements was $16.5 million and $29.2 million at December 31, 2005 and 2004, respectively. This amount is recorded in other noncurrent liabilities in the accompanying Consolidated Balance Sheets. Amortization expense on all above-market coal supply agreements was $8.0 million, $3.8 million and $16.6 million in 2005, 2004 and 2003, respectively. Amortization income on all below-market coal supply agreements was $16.0 million and $4.1 million at December 31, 2005 and 2004, respectively. Based on expected shipments related to these contracts, the Company expects to record annual amortization expense on the above-market coal supply agreements and annual amortization income on the below-market coal supply agreements in each of the next five years as reflected in the table below.

	Above-Market Contracts	Below-Market Contracts
2006	$ 1,731	$ 12,810
2007	1,168	2,754
2008	420	595
2009	420	310
2010	420	—

During 2003, the Company agreed to terms with a large customer seeking to buy out of the remaining term of an above-market coal supply contract. The buy-out resulted in the receipt of $52.5 million in cash. The Company wrote off the remaining contract value of $37.5 million and recorded a deferred gain of approximately $15.0 million related to this transaction. The deferred gain was recognized ratably over the remaining term of the contract. On December 31, 2005, this contract was sold as part of the Magnum transaction, and the Company recognized the remaining deferred gain of $12.0 million. See additional discussion of the Magnum transaction in Note 3, "Dispositions."

Exploration Costs

Costs related to locating coal deposits and evaluating the economic viability of such deposits are expensed as incurred.

Property, Plant and Equipment

Plant and Equipment

Plant and equipment are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Expenditures which extend the useful lives of existing plant and equipment or increase the productivity of the asset are capitalized. The cost of maintenance and repairs that do not extend the useful life or increase the productivity of the asset are expensed as incurred. Plant and equipment are depreciated principally on the straight-line method over the estimated useful lives of the assets, which generally range from three to 30 years except for preparation plants and loadouts. Preparation plants and loadouts are depreciated using the units-of-production method over the estimated recoverable reserves, subject to a minimum level of depreciation.

If facts and circumstances suggest that a long-lived asset may be impaired, the carrying value is reviewed for recoverability. If this review indicates that the carrying amount of the asset will not be recoverable through projected undiscounted cash flows related to the asset over its remaining life, then an impairment loss is recognized by reducing the carrying value of the asset to its fair value.

Deferred Mine Development

Costs of developing new mines or significantly expanding the capacity of existing mines are capitalized and amortized using the units-of-production method over the estimated recoverable reserves that are associated with the property being benefited. Additionally, the asset retirement obligation asset has been recorded as a component of deferred mine development.

Coal Lands and Mineral Rights

A significant portion of the Company’s coal reserves are controlled through leasing arrangements. Amounts paid to acquire such reserves are capitalized and depleted over the life of those reserves that are proven and probable. Depletion of coal lease rights is computed using the units-of-production method, and the rights are assumed to have no residual value. The leases are generally long-term in nature (original terms range from 10 to 50 years), and substantially all of the leases contain provisions that allow for automatic extension of the lease term as long as mining continues. The net book value of the Company’s leased coal interests was $908.7 million and $1,169.7 million at December 31, 2005 and 2004, respectively.

The Company has entered into various non-cancelable royalty lease agreements and federal lease bonus payments under which future minimum payments are due. On September 22, 2004, the Company was the successful bidder in a federal auction of certain mining rights in the 5,084-acre Little Thunder tract in the Powder River Basin of Wyoming. The Company’s lease bonus bid amounted to $611.0 million for the tract that is to be paid in five equal installments of $122.2 million. The first $122.2 million installment was paid in 2004 with the remaining four annual payments to be paid in fiscal years 2006 through 2009. These payments are capitalized as the cost of the underlying mineral reserves.

Goodwill

Goodwill represents the excess of purchase price and related costs over the value assigned to the net tangible and identifiable intangible assets of businesses acquired. In accordance with Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (“Statement No. 142”), goodwill is not amortized but is tested for impairment annually, or if certain circumstances indicate a possible impairment may exist. Impairment testing is performed at a reporting unit level. An impairment loss generally would be recognized when the carrying amount of the reporting unit exceeds the fair value of the reporting unit, with the fair value of the reporting unit determined using a discounted cash flow analysis.

Revenue Recognition

Coal sales revenues include sales to customers of coal produced at Company operations and coal purchased from other companies. The Company recognizes revenue from coal sales at the time risk of loss passes to the customer at the Company's mine locations at contracted amounts. Transportation costs are included in cost of sales and amounts billed by the Company to its customers for transportation are included in coal sales.

Other Operating Income

Other operating income reflects income from sources other than coal sales, including administration and production fees from Canyon Fuel (these fees ceased as of the July 31, 2004 acquisition by the Company of the remaining 35% interest in Canyon Fuel), royalties earned from properties leased to third parties, and gains and losses from dispositions of long-term assets. These amounts are recognized as services are performed or otherwise earned.

Asset Retirement Obligations

The Company's legal obligations associated with the retirement of long-lived assets are recognized at fair value at the time the obligations are incurred. Obligations are incurred at the time development of a mine commences for underground and surface mines or construction begins for support facilities, refuse areas and slurry ponds. The liability is determined using discounted cash flow techniques and is accreted to its present value at the end of each period. Accretion on the asset retirement obligation begins at the time the liability is incurred. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying amount of the related long-lived asset. Amortization of the related asset is recorded on a units-of-production basis over the mine's estimated recoverable reserves. See additional discussion in Note 11, "Asset Retirement Obligations."

Derivative Financial Instruments

Derivative financial instruments are accounted for in accordance with Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("Statement No. 133"), as amended. Statement No. 133 requires all derivative financial instruments to be reported on the balance sheet at fair value. Changes in fair value are recognized either in earnings or equity, depending on whether the transaction qualifies for hedge accounting, and if so, the nature of the underlying exposure being hedged and how effective the derivatives are at offsetting price movements in the underlying exposure.

The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives for undertaking various hedge transactions. The Company evaluates the effectiveness of its hedging relationships both at the hedge inception and on an ongoing basis. Any ineffectiveness is recorded in the Consolidated Statements of Income. Ineffectiveness recorded in the Company's

Consolidated Statements of Income for the years ended December 31, 2005, 2004 and 2003 was $1.0 million, $0.2 million and $0.4 million, respectively.

The Company is exposed to price risk related to the value of sulfur dioxide emission allowances that are a component of the quality adjustment provisions in many of its coal supply contracts. The Company has purchased put options and entered into swap contracts to reduce volatility in the price of sulfur dioxide emission allowances. These contracts serve to protect the Company from any downturn in the price of sulfur dioxide allowances. The put option agreements grant the Company the right to sell allowances at specified prices on specific dates. The swap agreements essentially fix the price the Company receives for allowances by allowing the Company to receive a fixed price, while paying a floating price. These contracts do not qualify for hedge accounting, and accordingly, all adjustments to record the positions at fair value are recorded in income. Other operating expenses on the Company's Consolidated Statements of Income reflect unrealized losses and gains related to these contracts of $(17.5) million for the year ended December 31, 2005.

The Company is also exposed to the risk of fluctuations in cash flows related to its purchase of diesel fuel. The Company enters into forward physical purchase contracts and heating oil swaps and call options to reduce volatility in the price of diesel fuel for its operations. As of December 31, 2005, approximately 79% of the Company's anticipated 2006 fuel usage has been fixed with heating oil swaps and call options. The changes in the heating oil price highly correlate to changes in diesel fuel prices, accordingly, the derivatives qualify for hedge accounting and the fair value of the derivatives is recorded with an adjustment to other comprehensive income.

The Company has utilized interest-rate swap agreements to modify the interest characteristics of outstanding Company debt. The swap agreements essentially convert variable-rate debt to fixed-rate debt. These agreements required the exchange of amounts based on variable interest rates for amounts based on fixed interest rates over the life of the agreement. The Company accrues amounts to be paid or received under interest-rate swap agreements over the lives of the agreements.

The Company had designated certain interest rate swaps as hedges of the variable rate interest payments due under the Arch Western term loans. Historical unrealized losses related to these swaps through June 25, 2003 were deferred as a component of Accumulated Other Comprehensive Loss. Subsequent to the repayment of the term loans on June 25, 2003, these deferred amounts are amortized as additional expense over the contractual terms of the swap agreements. For the years ended December 31, 2005, 2004 and 2003, the Company recognized $(2.3) million, $0.9 million and $13.4 million, respectively, of unrealized gains (losses) related to these swaps. For the years ended December 31, 2005, 2004 and 2003, the Company recognized $7.7 million, $8.3 million and $4.3 million of expense, respectively, related to the amortization of the balance in other comprehensive income. In the fourth quarter of 2005, the Company terminated these swaps.

Income Taxes

Deferred income taxes are based on temporary differences between the financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates for years during which taxes are expected to be paid or recovered.

Stock-Based Compensation

These financial statements include the disclosure requirements of Financial Accounting Standards Board Statement No. 123, *Accounting for Stock-Based Compensation* ("Statement No. 123"), as amended by Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation — Transition and Disclosure* ("Statement No. 148"). With respect to accounting for its stock options, as permitted under Statement No. 123, the Company has retained the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25 ("APB 25"), *Accounting for Stock Issued to Employees*, and related interpretations. Had compensation expense for stock option grants been determined based on the fair value at the grant dates consistent with the method of Statement No. 123, the Company's net income and earnings per common share would have been changed to the pro forma amounts as indicated in the following table:

	Year Ended December 31		
	2005	2004	2003
Net income available to common shareholders, as reported	$ 22,544	$ 106,519	$ 10,097
Add:			
Stock-based employee compensation included in reported net income, net of related tax effects	12,768	1,837	—
Deduct:			
Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(16,894)	(7,302)	(9,239)
Pro forma net income available to common shareholders	$ 18,418	$ 101,054	$ 858
Earnings per share:			
Basic earnings per share — as reported	$ 0.35	$ 1.91	$ 0.19
Basic earnings per share — pro forma	0.29	1.81	0.02
Diluted earnings per share — as reported	0.35	1.78	0.19
Diluted earnings per share — pro forma	0.28	1.70	0.02

Accounting Standards Issued and Not Yet Adopted

In November 2004, the FASB issued Statement of Financial Accounting Standards No. 151, *Inventory Costs, an amendment of ARB No. 43, Chapter 4* ("Statement No. 151"). Statement No. 151 amends the guidance in ARB No. 43, Chapter 4, "Inventory Pricing," to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs, and wasted material (spoilage). Provisions of this statement are effective for fiscal years beginning after June 15, 2005. The Company does not expect the adoption of this statement to have a material impact on its financial statements.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* ("Statement No. 123R"), which requires all public companies to measure compensation cost in the income statement for all share-based payments (including employee stock options) at fair value for interim and annual periods. On April 14, 2005, the Securities and Exchange Commission (“SEC”) delayed the implementation of Statement No. 123R from its original implementation date by six months for most registrants, requiring all public companies to adopt Statement No. 123R no later than the beginning of the first fiscal year beginning after June 15, 2005. The Company will adopt Statement No. 123R on January 1, 2006 using the modified-prospective method. Under this method, companies are required to recognize compensation cost for share-based payments to employees based on their grant-date fair value from the beginning of the fiscal period in which the recognition provisions are first applied. Measurement and recognition of compensation cost for awards that were granted prior to, but not vested as of, the date Statement No. 123(R) is adopted would be based on the same estimate of the grant-date fair value and the same recognition method used previously under Statement No. 123. Statement No. 123R also requires the benefits of tax deductions in excess of recognized compensation cost to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after adoption. The Company does not expect the effect of the adoption of Statement No. 123R to be significant.

On March 30, 2005, the FASB ratified the consensus reached by the Emerging Issues Task Force (“EITF”) on Issue No. 04-6, *Accounting for Stripping Costs in the Mining Industry.* This issue applies to stripping costs incurred in the production phase of a mine for the removal of overburden or waste materials for the purpose of obtaining access to coal that will be extracted. Under the EITF, stripping costs incurred during the production phase of the mine are variable production costs that are included in the cost of inventory produced and extracted during the period the stripping costs are incurred. Historically, the Company has associated stripping costs at its surface mining operations with the cost of tons of coal uncovered and has classified tons uncovered but not yet extracted as coal inventory (pit inventory). Pit inventory, reported as coal inventory, was $40.7 million at December 31, 2005. The guidance in this EITF consensus is effective for fiscal years beginning after December 15, 2005 for which the cumulative effect of adoption should be recognized as an adjustment to the beginning balance of retained earnings during the period. The Company adopted the change on January 1, 2006.

Reclassifications

Certain amounts in the prior years’ financial statements have been reclassified to conform with the classifications in the current year’s financial statements with no effect on previously-reported net income or stockholders’ equity.

2. Business Combinations

Canyon Fuel 35% Acquisition

On July 31, 2004, the Company purchased the 35% interest in Canyon Fuel that it did not own from ITOCHU Corporation. The purchase price, including related costs and fees, of $112.2 million was funded with cash of $90.2 million and a five-year, $22.0 million non-interest bearing note. Net of cash acquired, the fair value of the transaction totaled $97.4 million. As a result of the acquisition, the Company owns substantially all of the ownership interests of Canyon Fuel and no longer accounts for its investment in Canyon

Fuel on the equity method but consolidates Canyon Fuel in its financial statements. The results of operations of the Canyon Fuel mines are included in the Company's Western Bituminous segment.

The purchase accounting allocation related to the acquisition has been recorded in the accompanying consolidated financial statements as of, and for the period subsequent to, July 31, 2004. The following table summarizes the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition (dollars in thousands):

Accounts receivable	$ 7,432
Materials and supplies	3,751
Coal inventory	7,434
Other current assets	6,466
Property, plant, equipment and mine development	125,881
Accounts payable and accrued expenses	(10,379)
Coal supply agreements	(33,378)
Other noncurrent assets and liabilities, net	(9,823)
Total purchase price, net of cash received of $11.0 million	$ 97,384

Amounts allocated to coal supply agreements noted in the table above represent the liability established for the net below-market coal supply agreements to be amortized over the remaining terms of the contracts. The liability is classified as an other noncurrent liability on the accompanying Consolidated Balance Sheet. See Note 1, "Accounting Policies" for amortization related to coal supply agreements.

Triton Acquisition

On August 20, 2004, the Company acquired (1) Vulcan Coal Holdings, L.L.C., which owns all of the common equity of Triton Coal Company, LLC ("Triton"), and (2) all of the preferred units of Triton for a purchase price of $382.1 million, including transaction costs and working capital adjustments. In 2003, Triton was the nation's sixth largest coal producer and operated two mines in the Powder River Basin: North Rochelle and Buckskin. Following the consummation of the transaction, the Company completed an agreement to sell Buckskin to Kiewit Mining Acquisition Company ("Kiewit"). The net sales price for this second transaction was $73.1 million. The total purchase price, including related costs and fees, was funded with cash on hand, including the proceeds from the Buckskin sale, $22.0 million in borrowings under the Company's existing revolving credit facility and a $100.0 million term loan at its Arch Western Resources subsidiary. Upon acquisition, the Company integrated the North Rochelle mine with its existing Black Thunder mine in the Powder River Basin.

The purchase accounting allocations related to the acquisition have been recorded in the accompanying consolidated financial statements as of, and for the periods subsequent to, August 20, 2004. The following table summarizes the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition (dollars in thousands):

Accounts receivable	$ 14,233
Materials and supplies	4,161
Coal inventory	4,875
Other current assets	2,200
Property, plant, equipment and mine development	325,194
Coal supply agreements	8,486
Goodwill	40,032
Accounts payable and accrued expenses	(72,326)
Other noncurrent assets and liabilities, net	(22,135)
Total purchase price, net of cash received of $0.4 million	$ 304,720

Amounts allocated to coal supply agreements noted in the table above represent the value attributed to the net above-market coal supply agreements to be amortized over the remaining terms of the contracts. See Note 1, “Accounting Policies” for amortization related to coal supply agreements.

The goodwill amount above arose due to the delay in time between the execution of the acquisition agreement and the date of closing because of the Federal Trade Commission’s lawsuit to block the acquisition and is attributable to the loss of value from the tons mined during this period. Of the amount allocated to goodwill above, $34.4 million was deductible for income tax purposes.

Pro Forma Financial Information

The following unaudited pro forma financial information presents the combined results of operations of the Company, the remaining Canyon Fuel interest acquired from ITOCHU Corporation and the North Rochelle operations acquired from Triton on a pro forma basis, as though the purchases had occurred as of the beginning of each period presented. The pro forma financial information does not necessarily reflect the results of operations that would have occurred had the Company and the operations acquired from Canyon Fuel and Triton constituted a single entity during those periods:

	Year Ended December 31,	
	2004	2003
	(In thousands, except per share data)	
Revenues:		
As reported	$ 1,907,168	$ 1,435,488
Pro forma	2,156,958	1,876,205
Income before accounting changes:		
As reported	113,706	20,340
Pro forma	103,933	13,747
Net income available to common shareholders:		
As reported	106,519	10,097
Pro forma	96,746	1,058
Basic earnings per share:		
As reported	1.91	0.19
Pro forma	1.73	0.02
Diluted earnings per share:		
As reported	1.78	0.19
Pro forma	1.63	0.02

3. Dispositions

On December 31, 2005, the Company sold all of the stock of three subsidiaries and their four associated mining operations and coal reserves in Central Appalachia to Magnum. The three subsidiaries include Hobet Mining, Apogee Coal Company and Catenary Coal Company, which include the Hobet 21, Arch of West Virginia, Samples and Campbells Creek mining operations. Included in the sale were a total of 455.0 million tons of reserves. For the years ended December 31, 2005, 2004 and 2003, collectively, these subsidiaries sold 12.7 million, 14.0 million and 14.4 million tons of coal, had revenues of $509.8 million, $475.1 million and $424.3 million and had incurred losses from operations of $8.3 million, $3.8 million and $65.6 million, respectively. As a result of the sale, Magnum acquired all of the assets and liabilities of the subsidiaries including various employee liabilities of idle union properties whose former employees were signatory to a United Mine Workers of America (“UMWA”) contract.

In accordance with the terms of the transaction, the Company agreed to pay $50.2 million to Magnum in 2006 which has been recorded in current liabilities on the Consolidated Balance Sheet as of December 31, 2005. The Company recorded a loss of $65.4 million related to firm purchase commitments to supply below-market sales contracts that can no longer be sourced from its production as a result of the sale of these operations to Magnum. The loss related to the below-market legacy sales contracts was recorded as an accrued expense on the Consolidated Balance Sheet as of December 31, 2005. The net book value of the subsidiaries sold was a net liability of $123.1 million, consisting of the following:

Assets		
Current assets	$	87,300
Property, plant, equipment		309,100
Other assets		3,800
Total assets		400,200
Liabilities		
Current liabilities		(77,700)
Accrued postretirement benefits other than pension		(367,800)
Accrued workers' compensation		(15,400)
Reclamation and mine closure		(31,200)
Other noncurrent liabilities		(31,200)
Total liabilities		523,300
Net liabilities	$	123,100

The transaction resulted in a net gain to the Company of $7.5 million.

In accordance with the purchase and sale agreement with Magnum, the Company has agreed to various guarantees which are described in Note 20, "Guarantees."

On December 30, 2005, the Company completed a reserve swap with Peabody Energy Corp. ("Peabody") and sold to Peabody a rail spur, rail loadout and an idle office complex located in the Powder River Basin for a purchase price of $84.6 million. In the reserve swap, the Company exchanged 60.0 million tons of coal reserves for a similar block of 60.0 million tons of coal reserves with Peabody in order to facilitate more efficient mine plans for both companies. Due to the similarity of the exchanged reserves, the reserves received were recorded at the net book value of the reserves transferred. In conjunction with the transactions, the Company will continue to lease the rail spur and loadout and office facilities through 2008 while it mines adjacent reserves. The Company recognized a gain of $46.5 million on the transaction, after the deferral of $7.0 million of the gain, equal to the present value of the lease payments. The deferred gain will be recognized over the term of the lease. See further discussion in Note 18, "Leases."

During the years ended December 31, 2005, 2004 and 2003, gains on other dispositions of plant, property and equipment were $28.2 million, $6.7 million and $3.8 million, respectively, During 2005, in addition to the transactions discussed above, the Company recognized a gain of $9.0 million on the sale of surface land rights at its Central Appalachian operations in West Virginia, a gain of $6.3 million on the assignment of its rights and obligations on several parcels of land and a gain of $7.3 million on the sale of a dragline.

During the year ended December 31, 2004, the Company sold its rights and obligations on a parcel of land to a third party resulting in a gain of $5.8 million.

4. Accumulated Other Comprehensive Income

Other comprehensive income items under Statement of Financial Accounting Standards No. 130, *Reporting Comprehensive Income*, are transactions recorded in stockholders' equity during the year, excluding net income and transactions with stockholders. Following are the items included in other comprehensive income (loss), net of a 39% tax rate:

	Financial Derivatives	Minimum Pension Liability Adjustments	Available-for-Sale Securities	Accumulated Other Comprehensive Loss
Balance January 1, 2003	$ (23,170)	$ (19,267)	$ —	$ (42,437)
2003 activity	(989)	3,403	—	2,414
Balance December 31, 2003	(24,159)	(15,864)	—	(40,023)
2004 activity	8,524	1,221	2,081	11,826
Balance December 31, 2004	(15,635)	(14,643)	2,081	(28,197)
2005 activity	13,818	(2,751)	8,498	19,565
Balance December 31, 2005	$ (1,817)	$ (17,394)	$ 10,579	$ (8,632)

As discussed in Note 1, unrealized gains (losses) on derivatives that qualify for hedge accounting as cash flow hedges are recorded in other comprehensive income.

The unrealized gains and losses on recording the Company's "available-for-sale" securities at fair value is recorded through other comprehensive income.

5. Investments

The Company holds a 17.5% general partnership interest in Dominion Terminal Associates ("DTA"), which is accounted for on the equity method. DTA operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia used by the partners to transload coal. Financing for the facility was provided through $132.8 million of tax-exempt bonds issued by Peninsula Ports Authority of Virginia ("PPAV"). DTA leases the facility from PPAV for amounts sufficient to meet debt-service requirements. The Company retired its 17.5% share, or $23.2 million, of the bonds in the fourth quarter of 2005. Under the terms of a throughput and handling agreement with DTA, each partner is charged its share of cash operating and debt-service costs in exchange for the right to use the facility's loading capacity and is required to make periodic cash advances to DTA to fund such costs. The Company's portion of DTA's costs was $3.4 million, $2.7 million and

$2.8 million for the years ended December 31, 2005, 2004 and 2003, respectively. At December 31, 2005 and 2004, the Company had an investment in DTA of $8.5 million and a liability to fund DTA of $13.9 million, respectively.

Through July 31, 2004, the Company's income from its equity-method investment in Canyon Fuel represented 65% of Canyon Fuel's net income after adjusting for the effect of purchase adjustments related to its investment in Canyon Fuel. The Company's investment in Canyon Fuel reflects purchase adjustments primarily related to the reduction in amounts assigned to sales contracts, mineral reserves and other property, plant and equipment. The purchase adjustments are amortized consistently with the underlying assets of the joint venture. The Company purchased the remaining 35% interest in Canyon Fuel on July 31, 2004. The Company's income from its investment in Canyon Fuel for the seven months ended July 31, 2004 and the year ended December 31, 2003 was $8.4 million and $19.7 million, respectively. These costs are included in operating expenses in the Consolidated Statements of Income.

Effective January 1, 2003, Canyon Fuel adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("Statement No. 143") and recorded a cumulative effect loss of $2.4 million. The Company's 65% share of this amount was offset by purchase adjustments of $0.5 million. These amounts are included in the cumulative effect of accounting change reported in the Company's Consolidated Statements of Income.

On December 22, 2003, the Company sold its 4.8 million subordinated units and its general partner interest in Natural Resource Partners L.P. ("NRP") for a purchase price of $115.0 million. This sale resulted in a gain of $70.6 million, of which $42.7 million was recognized in 2003 and the remainder was deferred, as discussed below. During the year ended December 31, 2004, the Company sold its remaining limited partnership units of NRP, representing approximately 12.5% of NRP's outstanding partnership interests, in three separate transactions occurring in March, June and October. These sales resulted in proceeds of approximately $111.4 million and gains of $91.3 million. The Company's income from the equity investment in NRP was $2.4 million and $14.7 million for the years ended December 31, 2004 and 2003, respectively.

As of December 31, 2005 and 2004, the Company had deferred gains from its sales of NRP units totaling $8.2 million and $21.8 million, respectively, which are included as "Other noncurrent liabilities" in the accompanying Consolidated Balance Sheets. Certain leases with NRP related to the Company's operations sold as part of the Magnum transaction. The recognition of the gain of $5.8 million associated with these leases is included in the gain on the transaction with Magnum. The remaining deferred gains will be recognized over the remaining term of the Company's leases with NRP, as follows: $2.7 million in 2006, $2.2 million in 2007, and a total of $3.3 million from 2008 through 2012.

The fair value of investments in stock and other equity interests not accounted for under the equity method of accounting totaled $23,847 and $7,197 at December 31, 2005 and 2004, respectively.

6. Accrued Expenses

Accrued expenses included in current liabilities consist of the following:

	December 31, 2005	December 31, 2004
Payroll and related benefits	$ 33,739	$ 32,358
Taxes other than income taxes	59,828	76,246
Postretirement benefits other than pension	3,062	29,685
Workers' compensation	9,900	12,774
Interest	32,749	35,102
Asset retirement obligations	10,680	19,632
Losses on purchase commitments (see Note 3)	65,383	—
Due to Magnum (see Note 3)	16,000	—
Other accrued expenses	14,315	11,419
	$ 245,656	$ 217,216

7. Income Taxes

Significant components of the benefit from income taxes are as follows:

	December 31, 2005	December 31, 2004	December 31, 2003
Current:			
Federal	$ (13,703)	$ 7,583	$ 4,668
State	—	—	—
Total current	(13,703)	7,583	4,668
Deferred:			
Federal	(22,843)	(5,412)	(24,438)
State	1,896	(2,301)	(3,440)
Total deferred	(20,947)	(7,713)	(27,878)
	$ (34,650)	$ (130)	$ (23,210)

A reconciliation of the statutory federal income tax expense (benefit) on the Company's pretax income (loss) to the actual benefit for income taxes follows:

	December 31, 2005	2004	2003
Income tax expense (benefit) at statutory rate	$ 1,216	$ 39,760	$ (1,005)
Percentage depletion allowance	(34,752)	(22,807)	(16,211)
State taxes, net of effect of federal taxes	(3,805)	1,729	(2,123)
Change in valuation allowance, affecting provision	(6,138)	(265)	3,543
Termination of interest rate swaps	5,049	180	2,062
Reversal of reserve for capital loss	—	—	(5,850)
Favorable tax settlement	—	(16,861)	(1,464)
Other, net	3,780	(1,866)	(2,162)
	$ (34,650)	$ (130)	$ (23,210)

During 2005, compensatory stock options were exercised resulting in a tax benefit of $11.6 million that was recorded to paid-in capital.

During 2004, the IRS completed an audit and review of tax returns and claims for tax years 1999 through 2002 resulting in a favorable tax settlement, which includes a $9.7 million reduction in prior years' tax reserves. Also, compensatory stock options were exercised resulting in a tax benefit of $5.0 million that was recorded to paid-in capital.

During 2003, the Company reversed a $5.8 million tax reserve, which was established in prior years, for capital loss deductions which the Company deemed had no value at that time. Capital losses are only deductible to the extent that a company has capital gains. Capital gains generated during 2003 and projected to be generated in future years will fully absorb the capital loss. Also during the year, the Company reversed a $1.5 million tax reserve as a result of filing amended state income tax returns based on prior year IRS audit changes.

Management believes that the Company has adequately provided for any income taxes and interest which may ultimately be paid with respect to all open tax years.

Significant components of the Company's deferred tax assets and liabilities that result from carryforwards and temporary differences between the financial statement basis and tax basis of assets and liabilities are summarized as follows:

	December 31, 2005	December 31, 2004
Deferred tax assets:		
Net operating loss carryforwards	$ 187,122	$ 74,226
Alternative minimum tax credit carryforwards	99,782	99,582
Plant and equipment	88,213	19,143
Losses on purchase commitments	60,499	—
Reclamation and mine closure	32,563	42,776
Workers' compensation	21,704	32,453
Advance royalties	16,961	13,303
Postretirement benefits other than pension	12,942	152,622
Tax-based intangibles	11,574	13,880
Other comprehensive income	1,688	16,412
Other	43,289	42,696
Gross deferred tax assets	576,337	507,093
Valuation allowance	(163,163)	(163,005)
Total deferred tax assets	413,174	344,088
Deferred tax liabilities:		
Investment in tax partnerships	54,808	38,251
Deferred development	16,197	669
Pit inventory	15,842	12,920
Other	14,010	17,089
Total deferred tax liabilities	100,857	68,929
Net deferred tax asset	312,317	275,159
Less current asset	88,461	33,933
Long-term deferred tax asset	$ 223,856	$ 241,226

The Company has federal net operating loss carryforwards for regular income tax purposes of $435.3 million which will expire in the years 2007 to 2023. The Company has an alternative minimum tax credit carryforward of $83.2 million, which may carry forward indefinitely to offset future regular tax in excess of alternative minimum tax.

The Company has recorded a valuation allowance for a portion of its deferred tax assets that management believes, more likely than not, will not be realized. These deferred tax assets include a portion of the net operating losses, alternative minimum tax credits and certain deductible temporary differences that will likely not be realized at the maximum effective tax rate. The amount of the valuation allowance relating to stock option exercises for which the future benefit will be recorded in Paid-in Capital is $8.5 million.

8. Debt and Financing Arrangements

Debt consists of the following:

	December 31, 2005	December 31, 2004
Indebtedness to banks under revolving credit agreement, expiring December 22, 2009	$ —	$ 25,000
6.75% senior notes ($950.0 million face value) due July 1, 2013	960,246	961,613
Promissory note	14,676	17,523
Other	7,482	7,011
	982,404	1,011,147
Less current portion	10,649	9,824
Long-term debt	$ 971,755	$ 1,001,323

On December 22, 2004, the Company entered into a $700.0 million revolving credit facility that matures on December 22, 2009. The rate of interest on borrowings under the credit facility is a floating rate based on LIBOR. The Company’s credit facility is secured by substantially all of its assets as well as its ownership interests in substantially all of its subsidiaries, except its ownership interests in Arch Western and its subsidiaries. The credit facility replaced the Company’s existing $350.0 million revolving credit facility. At December 31, 2005, the Company had $96.5 million in letters of credit outstanding, resulting in $603.5 million of unused borrowings under the revolver. Financial covenant requirements may restrict the amount of unused capacity available to the Company for borrowings and letters of credit. As of December 31, 2005, the Company was not restricted by financial covenants.

On October 22, 2004, the Company issued $250.0 million of 6.75% Senior Notes due 2013 at a price of 104.75% of par. Interest on the notes is payable on January 1 and July 1 of each year, beginning on January 1, 2005. The senior notes were issued under an indenture dated June 25, 2003, under which the Company previously issued $700.0 million of 6.75% Senior Notes due 2013. The senior notes are guaranteed by Arch Western and certain of Arch Western’s subsidiaries and are secured by a security interest in loans made to Arch Coal by Arch Western. The terms of the senior notes contain restrictive covenants that limit Arch Western’s ability to, among other things, incur additional debt, sell or transfer assets, and make certain investments.

On July 31, 2004, the Company issued a five-year, $22.0 million non-interest bearing note to help fund the acquisition of the remainder of Canyon Fuel’s common stock. At its issuance, the note was discounted to its present value using a rate of 7.0%. The promissory note is payable in quarterly installments of $1.0 million through July 2008 and $1.5 million from October 2008 through July 2009.

The Company also periodically establishes uncommitted lines of credit with banks. These agreements generally provide for short-term borrowings at market rates. At December 31, 2005, there were $20.0 million of such agreements in effect, under which no loans were outstanding.

Aggregate contractual maturities of debt are $10.6 million in 2006, $3.3 million in 2007, $4.0 million in 2008, $4.3 million in 2009 and $960.2 million thereafter.

Terms of the Company's credit facilities and leases contain financial and other covenants that limit the ability of the Company to, among other things, effect acquisitions or dispositions and borrow additional funds and require the Company to, among other things, maintain various financial ratios and comply with various other financial covenants. In addition, the covenants require the pledging of assets to collateralize the Company's revolving credit facility. The assets pledged include equity interests in wholly-owned subsidiaries, certain real property interests, accounts receivable and inventory of the Company. Failure by the Company to comply with such covenants could result in an event of default, which, if not cured or waived, could have a material adverse effect on the Company. The Company was in compliance with all financial covenants at December 31, 2005.

9. Fair Values of Financial Instruments

The following methods and assumptions were used by the Company in estimating its fair value disclosures for financial instruments:

Cash and cash equivalents: The carrying amounts approximate fair value.

Debt: At December 31, 2005 and 2004, the fair value of the Company's senior notes and other long-term debt, including amounts classified as current, was $1,001.6 million and $1,000.6 million, respectively.

Derivatives.

As of December 31, 2005, the Company held heating oil swaps totaling 22.8 million gallons at a fixed price of $1.45 and heating oil call options totaling 9.3 million gallons at call prices from $1.70 to $2.05. The fair value of the heating oil swaps and calls of $8.7 million is reflected as a current asset in the Consolidated Balance Sheet at December 31, 2005.

As of December 31, 2005 the Company held swaps for 12,000 sulfur dioxide allowances with 6,000 expiring in 2006 and 2007 at a price of $815 and $825 in 2006 and 2007, respectively. The Company had put options for 48,000 sulfur dioxide allowances at prices from $600 to $1,200. The fair value of the sulfur dioxide swaps and puts is reflected as a current liability of $11.9 million and a current asset of $0.2 million, respectively, in the Consolidated Balance Sheet at December 31, 2005.

The Company terminated its outstanding interest rate swaps in the fourth quarter of 2005. The fair value of these swaps was $12.4 million at December 31, 2004.

10. Accrued Workers' Compensation

The Company is liable under the federal Mine Safety and Health Act of 1969, as subsequently amended, to provide for pneumoconiosis (black lung) benefits to eligible employees, former employees, and dependents. The Company is also liable under various states' statutes for black lung benefits. The Company currently provides for federal and state claims principally through a self-insurance program. Charges are being made to operations as determined by independent actuaries, at the present value of the actuarially computed present and future liabilities for such benefits over the employees' applicable years of service.

In addition, the Company is liable for workers' compensation benefits for traumatic injuries that are accrued as injuries are incurred. Traumatic claims are either covered through self-insured programs or through state-sponsored workers' compensation programs.

Workers' compensation expense consists of the following components:

	2005	2004	2003
Self-insured black lung benefits:			
Service cost	$ 1,159	$ 1,447	$ 1,491
Interest cost	1,852	2,660	2,942
Net amortization	(3,793)	(1,080)	(247)
Total black lung disease	(782)	3,027	4,186
Traumatic injury claims and assessments	20,196	18,725	14,008
Total provision	$ 19,414	$ 21,752	$ 18,194
Payments for worker's compensation benefits	$ 29,952	$ 21,068	$ 17,072
Discount rate	5.80%	6.00%	6.50%
Cost escalation rate	3.00%	4.00%	4.00%

Net amortization represents the systematic recognition of actuarial gains or losses over a five-year period.

Summarized below is information about the amounts recognized in the consolidated balance sheets for workers' compensation benefits:

	December 31,	
	2005	2004
Black lung costs	$ 26,670	$ 51,793
Traumatic and other workers' compensation claims	37,033	43,427
Total obligations	63,703	95,220
Less amount included in accrued expenses	9,900	12,774
Noncurrent obligations	$ 53,803	$ 82,446

The reconciliation of changes in the benefit obligation of the black lung liability is as follows:

	December 31, 2005	December 31, 2004
Beginning of year obligation	$ 47,641	$ 46,722
Service cost	1,159	1,447
Interest cost	1,852	2,660
Actuarial gain	(16,247)	(1,122)
Divestitures	(14,136)	—
Benefit and administrative payments	(3,362)	(2,066)
Net obligation at end of year	16,907	47,641
Unrecognized gain	9,763	4,152
Accrued cost	$ 26,670	$ 51,793

There were no receivables related to benefits contractually recoverable from others at December 31, 2005. Receivables related to benefits contractually recoverable from others of $0.4 million at December 31, 2004 are recorded in other long-term assets.

11. Asset Retirement Obligations

The Company's asset retirement obligations arise from the federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. The required reclamation activities to be performed are outlined in the Company's mining permits. These activities include reclaiming the pit and support acreage at surface mines, sealing portals at underground mines, and reclaiming refuse areas and slurry ponds.

The Company reviews its asset retirement obligation at least annually and makes necessary adjustments for permit changes as granted by state authorities and for revisions of estimates of amount and timing of costs. For ongoing operations, adjustments to the liability result in an adjustment to the corresponding asset. For idle operations, adjustments to the liability are recognized as income or expense in the period the adjustment is recorded.

Effective January 1, 2003, the Company began accounting for its reclamation obligations in accordance with Statement No. 143. The cumulative effect of this change on periods prior to January 1, 2003 resulted in a charge to income of $3.7 million (net of income taxes of $2.3 million), or $0.07 per share, which is included in the Company's results of operations for the year ended December 31, 2003.

The following table describes the changes to the Company's asset retirement obligation for the years ended December 31:

	2005	2004
Balance at January 1 (including current portion)	$ 199,597	$ 162,731
Accretion expense	14,950	12,681
Additions/(reductions) resulting from property additions/(disposals)	(33,339)	37,784
Adjustments to the liability from changes in estimates	4,191	(1,571)
Liabilities settled	(7,991)	(12,028)
Balance at December 31	177,408	199,597
Current portion included in accrued expenses	(10,680)	(19,632)
Long-term liability	$ 166,728	$ 179,965

12. Employee Benefit Plans

Defined Benefit Pension and Other Postretirement Benefit Plans

The Company has non-contributory defined benefit pension plans covering certain of its salaried and non-union hourly employees. Benefits are generally based on the employee's age and compensation. The Company funds the plans in an amount not less than the minimum statutory funding requirements nor more than the maximum amount that can be deducted for federal income tax purposes.

The Company also currently provides certain postretirement medical/life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement medical/life plans are contributory, with retiree contributions adjusted periodically, and contain other cost-sharing features such as deductibles and coinsurance. The postretirement medical plan for retirees who were members of the UMWA is not contributory. The Company's current funding policy is to fund the cost of all postretirement medical/life insurance benefits as they are paid.

During 2005, the postretirement benefit plans were amended to improve benefits to participants. As discussed in Note 3, "Dispositions," on December 31, 2005, the Company sold three of its subsidiaries with operations in Central Appalachia, along with the related postretirement benefit obligations. The only remaining participants in the postretirement benefit plan have their benefits capped at current levels. This disposition constituted a settlement of the Company's postretirement benefit obligation and a loss of $59.2 million was recognized.

The Company uses a December 31 measurement date for its pension and postretirement benefit plans.

Obligations and Funded Status. Summaries of the changes in the benefit obligations, plan assets and funded status of the plans are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligations at January 1	$ 218,063	$ 182,946	$ 535,870	$ 531,933
Service cost	11,072	8,861	5,592	4,145
Interest cost	12,655	11,781	31,866	29,695
Plan amendments	242	139	20,010	—
Acquisitions/(divestitures)	—	23,380	(455,294)	10,748
Benefits paid	(16,228)	(15,288)	(32,963)	(29,585)
Transfer from Canyon Fuel Pension Plan	—	57	—	—
Other-primarily actuarial (gain) loss	8,831	6,187	(40,047)	(11,066)
Benefit obligations at December 31	$ 234,635	$ 218,063	$ 65,034	$ 535,870
CHANGE IN PLAN ASSETS				
Value of plan assets at January 1	$ 191,109	$ 151,126	$ —	$ —
Actual return on plan assets	15,060	17,974	—	—
Acquisitions	—	15,599	—	—
Employer contributions	20,034	21,641	32,963	29,585
Benefits paid	(16,228)	(15,288)	(32,963)	(29,585)
Transfer from Canyon Fuel Pension Plan	—	57	—	—
Value of plan assets at December 31	$ 209,975	$ 191,109	$ —	$ —
NET AMOUNT RECOGNIZED				
Funded status of the plans	$ (24,660)	$ (26,954)	$ (65,034)	$ (535,870)
Unrecognized actuarial loss	37,567	34,683	4,149	129,753
Unrecognized prior service cost (gain)	(330)	(886)	16,497	(3,992)
Prepaid (accrued) benefit cost	$ 12,577	$ 6,843	$ (44,388)	$ (410,109)

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
BALANCE SHEET AMOUNTS				
Accrued benefit liabilities	$ (17,193)	$ (17,628)	$ (44,388)	$ (410,109)
Intangible asset (other assets)	766	592	—	—
Minimum pension liability adjustment (accumulated other comprehensive income)	29,004	23,879	—	—
Net asset (liability) recognized	$ 12,577	$ 6,843	$ (44,388)	$ (410,109)
Current	$ —	$ —	$ (3,062)	$ (29,685)
Long-term	$ 12,577	$ 6,843	$ (41,326)	$ (380,424)

Other Postretirement Benefits

The postretirement plan amendment relates to the enhancement of benefits to employees discussed above, which also resulted in the increase in the unrecognized prior service cost.

The actuarial gain in 2005 resulted from changes in certain actuarial assumptions, including changes in the cost claims curve. The actuarial gain in 2004 resulted from impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 implementation discussed below.

Pension Benefits

The accumulated benefit obligation for all pension plans was $227.0 million and $208.7 million at December 31, 2005 and 2004, respectively.

Transfers from the Canyon Fuel Company Pension Plan represent transfers of the actuarially determined benefit obligation and the related plan assets for employees who were transferred from Canyon Fuel to the Company in 2004 as a result of the acquisition of Canyon Fuel discussed in Note 2, “Business Combinations.”

Components of Net Periodic Benefit Cost. The following table details the components of pension and other postretirement benefit costs.

Year Ended December 31,	Pension Benefits 2005	Pension Benefits 2004	Pension Benefits 2003	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003
Service cost	$ 11,072	$ 8,861	$ 8,188	$ 5,592	$ 4,145	$ 3,637
Interest cost	12,655	11,781	11,293	31,866	29,695	31,126
Expected return on plan assets*	(15,944)	(14,539)	(13,687)	—	—	—
Other amortization and deferral	7,393	4,802	1,435	25,882	16,685	21,315
Settlements	—	—	—	59,195	—	—
Net benefit cost	$ 15,176	$ 10,905	$ 7,229	$ 122,535	$ 50,525	$ 56,078

* The Company does not fund its other postretirement liabilities.

Assumptions. The following table provides the assumptions used to determine the actuarial present value of projected benefit obligations at December 31.

	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Weighted average assumptions:				
Discount rate	5.80%	6.00%	5.80%	6.00%
Rate of compensation increase	3.50%	3.50%	N/A	N/A

The following table provides the assumptions used to determine net periodic benefit cost for years ended December 31.

	Pension Benefits 2005	Pension Benefits 2004	Pension Benefits 2003	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003
Weighted average assumptions:						
Discount rate	6.00%	6.50%	7.00%	6.00%	6.50%	7.00%
Rate of compensation increase	3.50%	3.75%	4.25%	N/A	N/A	N/A
Expected return on plan assets	8.50%	8.50%	9.00%	N/A	N/A	N/A

The Company establishes the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The Company utilizes modern portfolio theory modeling techniques in the development of its return assumptions. This technique projects rates of returns that can be generated through various asset allocations that lie within the risk tolerance set forth by members of the Company's pension committee (the "Pension Committee"). The risk assessment provides a link between a pension's risk capacity, management's willingness to accept investment risk and the asset allocation process, which ultimately leads to the return generated by the invested assets. For the determination of net periodic benefit cost in 2006, the Company will utilize an expected rate of return of 8.25%.

The following table provides information regarding the assumed health care cost trend rates at December 31.

	2005	2004
Health care cost trend rate assumed for next year	N/A	8.00%
Ultimate trend rate	N/A	5.00%
Year that the rate reaches the ultimate trend rate	N/A	2011

Because postretirement costs for remaining participants are capped at current levels, future changes in health care costs have no future effect on the plan benefits.

Increasing the assumed health care cost trend rate by one percentage point each year would have increased the net periodic postretirement benefit cost for 2005 by $4.0 million, or 3%.

Plan Assets. The Company's pension plan weighted average asset allocations by asset category are as follows:

	Plan Assets at December 31,	
	2005	2004
Equity securities	71%	67%
Debt securities	23%	28%
Cash and equivalents	6%	5%
Total	100%	100%

The Pension Committee is responsible for overseeing the investment of pension plan assets. The Pension Committee is responsible for determining and monitoring appropriate asset allocations and for selecting or replacing investment managers, trustees and custodians. The pension plan's current investment targets are 65% equity, 30% fixed income securities and 5% cash. The Pension Committee reviews the actual asset allocation in light of these targets on a periodic basis and rebalances among investments as necessary. The Pension Committee evaluates the performance of investment managers as compared to the performance of specified benchmarks and peers and monitors the investment managers to ensure adherence to their stated investment style and to the plan's investment guidelines.

Cash Flows. The Company is not required to make any contributions to its pension plans in 2006. The Company currently anticipates making contributions of approximately $21.0 million to the pension plan in 2006.

The following represents expected future benefit payments, which reflect expected future service, as appropriate:

	Pension Benefits	Other Postretirement Benefits
2006	$ 19,668	$ 3,653
2007	20,272	3,803
2008	21,245	3,962
2009	21,659	4,234
2010	21,796	4,615
Years 2011-2015	110,970	33,154
	$ 215,610	$ 53,421

Impact of Medicare Prescription Drug, Improvement and Modernization Act of 2003. On December 8, 2003, the President signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the “Act”). The Act introduces a prescription drug benefit under Medicare (“Medicare Part D”) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. The Company has included the effects of the Act in its financial statements for the year ended December 31, 2004 in accordance with FASB Staff Position No. FAS 106-2, *Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (“FSP 106-2”). Incorporation of the provisions of the Act resulted in a reduction of the Company’s postretirement benefit obligation of $68.0 million. The effect of the Act on postretirement medical expense for fiscal year 2004 and 2005 was a decrease of approximately $18.0 million (substantially all of which is recorded as a component of cost of coal sales). The benefits were partially offset by increased costs resulting from changes to other actuarial assumptions that were incorporated at the beginning of the year.

Multi-employer Pension and Benefit Plans

The Company made no payments in 2005, 2004 and 2003 into a multi-employer defined benefit pension plan trust established for the benefit of union employees under the labor contract with the UMWA. Payments are based on hours worked and are expensed as hours are incurred. Under the Multi-employer Pension Plan Amendments Act of 1980, a contributor to a multi-employer pension plan may be liable, under certain circumstances, for its proportionate share of the plan’s unfunded vested benefits (withdrawal liability). The Company is not aware of any circumstances that would require it to reflect its share of unfunded vested pension benefits in its financial statements. During 2005, approximately 13% of the Company’s workforce was represented by the UMWA under a collective bargaining agreement that is effective through December 31, 2006. With the sale of the Central Appalachian operations discussed in Note 3, “Dispositions,” the Company no longer has employees represented by the UMWA.

The Coal Industry Retiree Health Benefit Act of 1992 (“Benefit Act”) provides for the funding of medical and death benefits for certain retired members of the UMWA through premiums to be paid by assigned operators (former employers), transfers in 1993 and 1994 from an overfunded pension trust established for the benefit of retired UMWA members, and transfers from the Abandoned Mine Lands Fund (funded by a federal tax on coal production) commencing in 1995. The Company treats its obligation under the Benefit Act as a participation in a multi-employer plan and records expense as premiums are paid. The Company recorded expense of $3.4 million, $6.0 million and $5.1 million in the years ended December 31, 2005, 2004 and 2003 for premiums pursuant to the Benefit Act.

Other Plans

The Company sponsors savings plans which were established to assist eligible employees in providing for their future retirement needs. The Company's expense representing its contributions to the plans were $12.4 million, $8.8 million and $8.3 million for the years ended December 31, 2005, 2004 and 2003, respectively.

13. Capital Stock

On November 24, 2004, the Company filed a registration statement on Form S-3 with the SEC. The registration statement allows the Company to offer, from time to time, an aggregate of up to $1.0 billion in debt securities, preferred stock, depositary shares, purchase contracts, purchase units, common stock and related rights and warrants.

Common Stock

On October 28, 2004, the Company completed a public offering of 7,187,500 common shares at $33.85 per share. The proceeds from the offering, net of the underwriters' discount and related expenses, were $230.5 million. Net proceeds from the offering were used primarily to repay borrowings under the Company's revolving credit facility incurred to finance the acquisition of Triton and the first annual payment under the Little Thunder lease, and the remaining net proceeds will be used for general corporate purposes, including the development of the Mountain Laurel mine complex in the Central Appalachia Basin.

Preferred Stock

On December 1, 2005, the Company issued a tender offer to induce conversion of its 5% Perpetual Cumulative Convertible Preferred Stock ("Preferred Stock") to common shares (the "Conversion Offer"). The Conversion Offer expired on December 30, 2005. On December 31, 2005, the Company accepted for conversion 2,724,418 shares of Preferred Stock to be converted to 6,654,119 shares of common stock, including a conversion premium of 0.0439 shares. The Company recognized a dividend on the Preferred Stock in the amount of $9.5 million, representing the difference in the fair market value of the shares issued in conversion and those convertible pursuant to the original conversion terms.

On January 31, 2003, the Company completed a public offering of 2,875,000 shares of Preferred Stock. The net proceeds realized by the Company from the offering of $139.0 million were used to reduce indebtedness under the Company's revolving credit facility, and for working capital and general corporate purposes. Dividends on the Preferred Stock are cumulative and payable quarterly at the annual rate of 5% of the liquidation preference. Each share of the Preferred Stock is initially convertible, under certain conditions, into 2.3985 shares of the Company's common stock. The Preferred Stock is redeemable, at the Company's option, on or after January 31, 2008 if certain conditions are met. The holders of the Preferred Stock are not entitled to voting rights on matters submitted to the Company's common shareholders. However, if the Company fails to pay the equivalent of six quarterly dividends, the holders of the Preferred Stock will be entitled to elect two directors to the Company's Board of Directors.

Stock Repurchase Plan

Pursuant to a stock repurchase plan, the Company may repurchase up to 6.0 million of its shares of common stock. At December 31, 2005, 5.6 million shares of common stock were available for repurchase under the plan. The repurchased shares are being held in the Company's treasury, which the Company accounts for using the average cost method. Future repurchases under the plan will be made at management's discretion and will depend on market conditions and other factors. During 2005, 273,000 treasury shares were contributed to the pension plans.

14. Stockholder Rights Plan

Under a stockholder rights plan, preferred share purchase rights ("Preferred Purchase Rights") entitle their holders to purchase one one-hundredth of a share of a series of junior participating preferred stock at an exercise price of $42. The Preferred Purchase Rights are exercisable only when a person or group (an "Acquiring Person") acquires 20% or more of the Company's common stock or if a tender or exchange offer is announced which would result in ownership by a person or group of 20% or more of the Company's common stock. In certain circumstances, the Preferred Purchase Rights allow the holder (except for the Acquiring Person) to purchase the Company's common stock or voting stock of the Acquiring Person at a discount. The Board of Directors has the option to allow some or all holders (except for the Acquiring Person) to exchange their rights for Company common stock. The rights will expire on March 20, 2010, subject to earlier redemption or exchange by the Company as described in the plan.

15. Stock Incentive Plan and Other Incentive Plans

The Company's Stock Incentive Plan (the "Company Incentive Plan") reserved 9,000,000 shares of the Company's common stock for awards to officers and other selected key management employees of the Company. The Company Incentive Plan provides the Board of Directors with the flexibility to grant stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance stock or units, merit awards, phantom stock awards and rights to acquire stock through purchase under a stock purchase program ("Awards"). Awards the Board of Directors elects to pay out in cash do not count against the 9,000,000 shares authorized in the Company Incentive Plan.

As of December 31, 2005, stock options, performance units, restricted stock units and price contingent stock awards were the types of awards granted. Each is discussed more fully below.

Stock Options

Stock options are generally subject to vesting provisions of at least one year from the date of grant and are granted at a price equal to 100% of the fair market value of the stock on the date of grant. Information regarding stock options under the Company Incentive Plan follows for the years ended December 31, 2005, 2004 and 2003 (options in thousands):

	2005		2004		2003	
	Common Shares	Weighted Average Price	Common Shares	Weighted Average Price	Common Shares	Weighted Average Price
Options outstanding at January 1	2,965	$ 20.85	4,622	$ 21.29	5,485	$ 20.85
Granted	32	$ 38.80	6	$ 33.61	114	$ 19.23
Exercised	(1,519)	$ 21.19	(1,658)	$ 22.15	(771)	$ 17.54
Canceled	(20)	$ 24.86	(5)	$ 21.46	(206)	$ 22.60
Options outstanding at December 31	1,458	$ 20.80	2,965	$ 20.85	4,622	$ 21.29
Options exercisable at December 31	971	$ 20.54	1,783	$ 21.15	2,692	$ 21.94
Options available for grant at December 31	2,397		2,677		2,981	

The Company applies APB 25 and related interpretations in accounting for the Company Incentive Plan. Accordingly, no compensation expense has been recognized for the fixed stock option portion of the Company Incentive Plan. The after-tax fair value of options granted in 2005, 2004 and 2003 was determined to be $0.4 million, $0.1 million and $0.7 million, respectively, which for purposes of the pro forma disclosure in Note 1, “Accounting Policies,” is recognized as compensation expense over the options’ vesting period. The fair value of the options was determined using the Black-Scholes option pricing model and the weighted average assumptions noted below. Substantially all stock options granted vest ratably over three years, with the majority vesting in 2006.

	2005	2004	2003
Weighted average fair value per share of options granted	$ 16.90	$ 15.38	$ 8.33
Assumptions (weighted average):			
Risk-free interest rate	3.70%	3.65%	2.84%
Expected dividend yield	0.9%	1.0%	1.5%
Expected volatility	51.1%	52.7%	53.5%
Expected life (in years)	5.0	5.0	5.0

The table below shows pertinent information on options outstanding at December 31, 2005 (options in thousands):

	Options Outstanding			Options Exercisable	
Range of Exercise prices	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 8.50-$10.69	93	3.21	$ 10.58	93	$ 10.58
$ 16.09-$21.95	592	6.08	18.75	355	19.16
$ 22.00-$22.82	524	6.31	22.59	306	22.60
$ 22.875-$22.90	161	1.26	22.89	161	22.89
$ 23.45-$35.30	86	4.37	30.42	56	27.81
$ 67.51	2	9.79	67.51	—	—
	1,458	5.35	$ 20.80	971	$ 20.54

Performance Units

Performance stock or unit awards can be earned by the recipient if the Company meets certain pre-established performance measures. Until earned, the performance awards are nontransferable, and when earned, performance awards are payable in cash, stock, or restricted stock as determined by the Company’s Board of Directors. In January 2004, the Company granted performance unit awards that are earned if the Company meets certain financial, safety and environmental targets during the three years ending December 31, 2006. Amounts accrued during 2005 and 2004 for these awards totaled $3.3 million and $3.1 million, respectively. During the fourth quarter of 2003, the Company’s Board of Directors approved awards under a four-year performance unit plan that began in 2000 totaling $19.6 million (including $1.9 million awarded to employees of Canyon Fuel), which was paid in cash in the first quarter of 2004.

Restricted Stock and Restricted Stock Unit Awards

The restricted stock and restricted stock units require no payment from the employee. Compensation expense is based on the fair value on the grant date and is recorded ratably over the vesting period of three years. During the vesting period, the employee receives compensation equal to dividends declared on common shares.

During 2005 and 2004, restricted stock and restricted stock unit grants, net of cancellations, totaled 55,195 and 149,190 shares, respectively at a weighted average fair value of $57.81 and $28.47 per share, respectively. Expenses of $2.2 million and $2.4 million were recorded during 2005 and 2004, respectively.

On December 18, 2002, the Company granted a restricted stock unit award of 50,000 shares. The fair value of the shares on the date of grant was $21.11 per share. The units will vest in their entirety on January 31, 2008. The Company will recognize compensation expense in the amount of the total fair value of the grant ratably over the vesting period of the award.

Price Contingent Stock Awards

In the third quarter 2005, the Company's Board of Directors approved a performance-contingent phantom stock plan for 11 of its executives. The plan allows for participants to earn up to 252,600 units to be paid out in both cash and stock upon simultaneous attainment of certain levels of stock price and EBITDA, as defined by the Company. The Company recognized $4.5 million of expense related to this plan in the fourth quarter of 2005, as the Company's projections indicate that targets will be met in 2006 and a projected payout of $15.0 million will be made.

On January 14, 2004, the Company granted an award of 220,766 shares of performance-contingent phantom stock that vested in the event the Company's stock price reached an average pre-established price over a period of 20 consecutive trading days within five years following the date of grant. On March 3, 2005, the price contingency discussed above was met, and the award was paid in a combination of Company stock ($7.3 million) and cash ($2.6 million). As such, the Company recognized a $9.9 million charge as a component of selling, general and administrative expense ($9.1 million) and cost of coal sales ($0.8 million) in the accompanying Consolidated Statements of Income.

16. Risk Concentrations

Credit Risk and Major Customers

The Company places its cash equivalents in investment-grade short-term investments and limits the amount of credit exposure to any one commercial issuer.

The Company markets its coal principally to electric utilities in the United States. Sales to customers in foreign countries were $166.0 million and $134.0 million for the years ended December 31, 2005 and 2004. As of December 31, 2005 and 2004, accounts receivable from electric utilities located in the United States totaled $146.6 million and $127.7 million, respectively, or 82% and 71% of total trade receivables for 2005 and 2004, respectively. Generally, credit is extended based on an evaluation of the customer's financial condition, and collateral is not generally required. Credit losses are provided for in the financial statements and historically have been minimal.

The Company is committed under long-term contracts to supply coal that meets certain quality requirements at specified prices. These prices are generally adjusted based on indices. Quantities sold under some of these contracts may vary from year to year within certain limits at the option of the customer. The Company and its operating subsidiaries sold approximately 140.2 million tons of coal in 2005. Approximately 70% of this tonnage (representing 69% of the Company's revenue) was sold under long-term contracts (contracts having a term of greater than one year). Prices for coal sold under long-term contracts ranged from $5.78 to $86.42 per ton. Long-term contracts ranged in remaining life from one to 12 years. Some of these contracts include pricing which is above current market prices. Sales (including spot sales) to major customers were as follows (in thousands):

	2005	2004	2003
TVA	$ 306,896	$ 147,338	$ 80,510
AEP	221,334	173,528	222,580
Progress Energy	199,514	228,203	165,514

Transportation

The Company depends upon barge, rail, truck and belt transportation systems to deliver coal to its customers. Disruption of these transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could temporarily impair the Company's ability to supply coal to its customers, resulting in decreased shipments. Disruptions in rail service in 2004 and 2005 resulted in missed shipments and production interruptions. The Company has no long-term contracts with transportation providers to ensure consistent and reliable service.

17. Earnings (Loss) per Share

The following table sets forth the computation of basic and diluted earnings (loss) per common share:

	2005		
	Numerator (Income)	Denominator (Shares)	Per Share Amount
Basic EPS:			
Net income	$ 38,123	63,652	$ 0.59
Preferred stock dividends	(15,579)		(0.24)
Basic income available to common shareholders	$ 22,544		$ 0.35
Effect of dilutive securities:			
Effect of common stock equivalents arising from stock options and restricted stock grants	—	957	
Effect of common stock equivalents arising from convertible preferred stock	18	361	
Diluted EPS:			
Diluted income available to common shareholders	$ 22,562	64,970	$ 0.35

	2004		
	Numerator (Income)	Denominator (Shares)	Per Share Amount
Basic EPS:			
Net income	$ 113,706	55,901	$ 2.04
Preferred stock dividends	(7,187)		(0.13)
Basic income available to common shareholders	$ 106,519		$ 1.91
Effect of dilutive securities:			
Effect of common stock equivalents arising from stock options and restricted stock grants	—	937	
Effect of common stock equivalents arising from convertible preferred stock	7,187	6,896	
Diluted EPS:			
Diluted income available to common shareholders	$ 113,706	63,734	$ 1.78

	2003		
	Numerator (Income)	Denominator (Shares)	Per Share Amount
Basic EPS:			
Net income before cumulative effect of accounting change	$ 20,340	52,511	$ 0.39
Cumulative effect of accounting change	(3,654)		(0.07)
Preferred stock dividends	(6,589)		(0.13)
Basic income available to common shareholders	$ 10,097		$ 0.19
Effect of dilutive securities:			
Effect of common stock equivalents arising from stock options	—	374	
Diluted EPS:			
Net income before cumulative effect of accounting change	$ 20,340	52,885	$ 0.38
Cumulative effect of accounting change	(3,654)		(0.07)
Preferred stock dividends	(6,589)		(0.12)
Diluted income available to common shareholders	$ 10,097		$ 0.19

At December 31, 2005, 6,535,000 shares, representing the common stock conversion equivalent of the preferred stock converted on December 31, 2005, and $15.6 million, representing the related dividends and conversion inducement, were excluded from the diluted earnings per share calculation because their effect was anti-dilutive.

At December 31, 2003, 0.2 million shares were not included in the diluted earnings per share calculation since the exercise price was greater than the average market price. The effect of assumed conversion of the preferred stock was anti-dilutive and, therefore, not included in the diluted earnings per share calculation for 2003.

18. Leases

The Company leases equipment, land and various other properties under non-cancelable long-term leases, expiring at various dates. Certain leases contain options that would allow the Company to extend the lease or purchase the leased asset at the end of the base lease term. Rental expense related to these operating leases amounted to $31.8 million in 2005, $22.7 million in 2004 and $17.4 million in 2003. The Company has also entered into various non-cancelable royalty lease agreements and federal lease bonus payments under which future minimum payments are due.

Minimum payments due in future years under these agreements in effect at December 31, 2005 are as follows (in thousands):

	Operating Leases	Royalties
2006	$ 24,089	$ 26,390
2007	22,504	24,997
2008	20,898	23,938
2009	16,600	23,673
2010	13,478	23,054
Thereafter	42,078	44,742
	$ 139,647	$ 166,794

On December 31, 2005, the Company sold its rail spur, rail loadout and idle office complex at its Thunder Basin mining complex in Wyoming, which it will lease back while it mines adjacent reserves. The Company will pay $0.2 million per month through September 2008, with an option to extend on a month-to-month basis through September 2010. The Company deferred $7.0 million of the gain on the sale, equal to the present value of the minimum lease payments, to be amortized over the term of the lease.

19. Related Party Transactions

The Company received administration and production fees from Canyon Fuel for managing the Canyon Fuel operations through July 31, 2004, when the Company purchased the 35% interest it did not previously own. The fee arrangement was calculated annually and approved by the Canyon Fuel Management Board. The production fee was calculated on a per-ton basis while the administration fee represented the costs incurred by the Company’s employees related to Canyon Fuel administrative matters. The fees recognized as other operating income by the Company and as expense by Canyon Fuel were $4.8 million and $8.5 million for the years ended December 31, 2004 and 2003, respectively.

From October 2002 through October 2004, the Company held an ownership interest in NRP. The Company leases certain coal reserves from NRP and pays royalties to NRP for the right to mine those reserves.

Terms of the leases require the Company to prepay royalties with those payments recoupable against production. Amounts recognized as cost of coal sales for royalties paid to NRP during the years ended December 31, 2004 and 2003 were $15.4 million and $12.6 million, respectively.

20. Guarantees

In accordance with the purchase and sale agreement with Magnum, the Company has agreed to continue to provide surety bonds and letters of credit for reclamation and workers' compensation obligations of Magnum related to the properties sold in order to facilitate an orderly transition. The purchase and sale agreement requires Magnum to reimburse the Company for costs related to the surety bonds and letters of credit and to use commercially reasonable efforts after closing to replace the obligations. If the surety bonds and letters of credit related to the reclamation obligations are not replaced by Magnum within two years of closing of the transaction, then Magnum must post a letter of credit in favor of the Company in the amounts of the obligations. If letters of credit related to the workers' compensation obligation are not replaced within 360 days following the closing of the transaction, Magnum shall post a letter of credit in favor of the Company in the amounts of the obligation. Of the surety bonds related to reclamation obligations, $92.8 million relates to properties sold to Magnum while $10.5 million of letters of credit related to the retiree healthcare obligation relates to the properties sold to Magnum.

In addition, the Company has agreed to guarantee the performance of Magnum with respect to three coal sales contracts and several property leases sold to Magnum. If Magnum is unable to perform with respect to the coal sales contracts, the Company would be required to purchase coal on the open market or supply the contract from its existing operations. If the Company purchased all of the coal for these contracts at market prices effective at December 31, 2005, it would incur a loss of approximately $654.0 million related to the contracts. If Magnum is unable to perform with respect to the property leases, the Company would be responsible for future minimum royalty payments of approximately $12.4 million. The Company believes that it is remote that the Company would be liable for any obligation related to these guarantees. However, if the Company was to have to perform under these guarantees, it could potentially have a material adverse effect on the business, results of operations and financial condition of the Company.

In connection with the Company's acquisition of the coal operations of Atlantic Richfield Company ("ARCO") and the simultaneous combination of the acquired ARCO operations and the Company's Wyoming operations into the Arch Western joint venture, the Company agreed to indemnify another member of Arch Western against certain tax liabilities in the event that such liabilities arise prior to June 1, 2013 as a result of certain actions taken, including the sale or other disposition of certain properties of Arch Western, the repurchase of certain equity interests in Arch Western by Arch Western or the reduction under certain circumstances of indebtedness incurred by Arch Western in connection with the acquisition. If the Company were to become liable, the maximum amount of potential future tax payments was $193.3 million at December 31, 2005, of which none is recorded as a liability on the Company's financial statements. Since the indemnification is dependent upon the initiation of activities within the Company's control and the Company does not intend to initiate such activities, it is remote that the Company will become liable for any obligation related to this indemnification. However, if such indemnification obligation were to arise, it could potentially have a material adverse effect on the business, results of operations and financial condition of the Company.

In addition, tax reporting applied to this transaction by the other member of Arch Western is under review by the IRS. The Company does not believe it is probable that it will be impacted by the outcome of this review. If the outcome of this review results in adjustments, the Company may be required to adjust its deferred income taxes associated with its investment in Arch Western. Given the uncertainty of an adverse outcome impacting the Company's deferred income tax position as well as offsetting tax positions that the Company may be able to take, the Company is not able to determine a range of the potential outcomes related to this issue. Any change that impacts the Company related to the IRS review of the other member of this transaction potentially could have a material adverse impact on its financial statements.

21. Contingencies

The Company is a party to numerous claims and lawsuits with respect to various matters. The Company provides for costs related to contingencies when a loss is probable and the amount is reasonably determinable. After conferring with counsel, it is the opinion of management that the ultimate resolution of pending claims will not have a material adverse effect on the consolidated financial condition, results of operations or liquidity of the Company.

In response to a declaratory judgment action filed by the Company's subsidiary, Ark Land Company ("Ark Land"), in Mingo County, West Virginia, against a landowner involving the interpretation of a severance deed under which Ark Land controls the coal and mining rights on property in Mingo County, West Virginia, the landowner filed a counterclaim against Ark Land and a third party complaint against the Company and two of its other subsidiaries seeking damages for trespass, nuisance and property damage arising out of the exercise of rights under the severance deed on the property by the Company's subsidiaries. The defendant alleged that the Company's subsidiaries had insufficient rights to haul certain foreign coals across the property without payment of certain wheelage or other fees to the defendant. In addition, the defendant alleged that the Company and its subsidiaries violated West Virginia's Standards for Management of Waste Oil and the West Virginia Surface Coal Mining and Reclamation Act. This case went to trial on October 4, 2005. The landowner's counterclaim against Ark Land was dismissed along with its cross claim against one of the Company's subsidiaries and its claims for trespass, nuisance and wheelage. On October 12, 2005, the jury entered a verdict in favor of the landowner on its remaining claims, assessing damages against the Company and its subsidiary in the amount of $2.5 million. The jury found in the Company's favor on its indemnity claim against the Company's subsidiary's contractor, and awarded the Company $1.25 million on that claim. The landowner also was awarded its reasonable attorneys' fees, which have not yet been determined. The Company has reached a settlement in principle with the landowner and the settlement is reflected in the Company's financial statements.

A landowner filed a lawsuit in the Circuit Court for Kanawha County, West Virginia, claiming, among other things, that Ark Land, who leased West Virginia real estate from the landowner in exchange for royalties, misrepresented certain facts involving a lease amendment and that it miscalculated and underpaid royalties under the lease. The suit sought damages of approximately $14.5 million. Ark Land disputed its claims and filed a counterclaim for overpayment of royalties in the approximate amount of $260,000. The court directed the parties to arbitrate their dispute in accordance with the terms of their lease. The arbitration began on October 31, 2005, but the parties reached a settlement before the arbitrators decided the case. Under the terms of the settlement, the Company agreed to pay the landowner $16.0 million in complete settlement of all claims against the Company, which is reflected in the Consolidated Statement of Income in other expenses in the year ended December 31, 2005.

22. Cash Flow

The changes in operating assets and liabilities as shown in the consolidated statements of cash flows are comprised of the following:

	Year Ended December 31,		
	2005	2004	2003
Decrease (increase) in operating assets:			
Receivables	$ (48,432)	$ (31,570)	$ 18,805
Inventories	(38,368)	(12,422)	(2,857)
Increase (decrease) in operating liabilities:			
Accounts payable and accrued expenses	108,536	(6,780)	8,844
Income taxes	(33,513)	(4,215)	(13,822)
Accrued postretirement benefits other than pension	28,660	18,019	27,558
Asset retirement obligations	(8,631)	(7,555)	(20,606)
Accrued workers' compensation	(9,705)	(1,257)	(3,313)
Other	14,701	(21,626)	(14,984)
Changes in operating assets and liabilities	$ 13,248	$ (67,406)	$ (375)

23. Segment Information

The Company produces steam and metallurgical coal from surface and underground mines for sale to utility, industrial and export markets. The Company operates only in the United States, with mines in the major low-sulfur coal basins. The Company has three reportable business segments, which are based on the coal basins in which the Company operates. Coal quality, coal seam height, transportation methods and regulatory issues are generally consistent within a basin. Accordingly, market and contract pricing have developed by coal basin. The Company manages its coal sales by coal basin, not by individual mine complex. Mine operations are evaluated based on their per-ton operating costs (defined as including all mining costs but excluding pass-through transportation expenses). The Company's reportable segments are Powder River Basin (PRB), Central Appalachia (CAPP) and Western Bituminous (WBIT). The Company's operations in the Powder River Basin are located in Wyoming and include one operating surface mine and one idle surface mine. The Company's operations in Central Appalachia are located in southern West Virginia, eastern Kentucky and Virginia and include 10 underground mines and five surface mines. The Company's Western Bituminous operations are located in southern Wyoming, Colorado and Utah and include four underground mines (one of which was idled in May 2004) and two inactive surface mines in reclamation mode.

Operating segment results for the years ended December 31, 2005, 2004, and 2003 are presented below. Results for the operating segments include all direct costs of mining. Corporate, Other and Eliminations includes corporate overhead, land management, other support functions, and the elimination of intercompany transactions.

	PRB	CAPP	WBIT	Corporate, Other and Eliminations	Consolidated
December 31, 2005					
Coal sales	$ 756,874	$ 1,349,666	$ 402,233	$ —	$ 2,508,773
Income (loss) from operations	132,174	(15,830)	59,747	(98,234)	77,857
Total assets	1,333,289	786,091	1,723,744	(791,684)	3,051,440
Depreciation, depletion and amortization	106,870	70,605	33,364	1,462	212,301
Capital expenditures	30,668	235,313	77,932	13,229	357,142
Operating cost per ton	7.21	43.24	16.40		

	PRB	CAPP	WBIT	Corporate, Other and Eliminations	Consolidated
December 31, 2004					
Coal sales	$ 582,421	$ 1,126,258	$ 198,489	$ —	$ 1,907,168
Income from equity investments	—	—	8,410	2,418	10,828
Income from operations	72,441	39,196	18,145	48,264	178,046
Total assets	1,154,317	2,088,224	1,663,764	(1,649,770)	3,256,535
Depreciation, depletion and amortization	78,074	62,761	24,113	1,374	166,322
Capital expenditures	55,035	84,450	23,276	129,844	292,605
Operating cost per ton	6.19	34.84	15.71		

	PRB	CAPP	WBIT	Corporate, Other and Eliminations	Consolidated
December 31, 2003					
Coal sales	$ 409,352	$ 917,981	$ 108,155	$ —	$ 1,435,488
Income from equity investments	—	—	19,707	14,683	34,390
Income (loss) from operations	57,118	(43,872)	22,951	4,174	40,371
Total assets	975,796	1,964,384	1,087,508	(1,640,039)	2,387,649
Equity investments	—	—	146,180	25,865	172,045
Depreciation, depletion and amortization	44,202	64,980	18,851	30,431	158,464
Capital expenditures	18,351	47,527	8,971	57,578	132,427
Operating cost per ton	5.45	30.87	15.41		

A reconciliation of segment income from operations to consolidated income (loss) before income taxes and cumulative effect of accounting change follows:

	2005	2004	2003
Income from operations	$ 77,857	$ 178,046	$ 40,371
Interest expense	(72,409)	(62,634)	(50,133)
Interest income	9,289	6,130	2,636
Other non-operating income (expense)	(11,264)	(7,966)	4,256
Income (loss) before income taxes and cumulative effect of accounting change	$ 3,473	$ 113,576	$ (2,870)

24. Quarterly Financial Information (Unaudited)

Quarterly financial data for 2005 and 2004 is summarized below:

	March 31 (a)(b)(c)	June 30 (b)	September 30 (a)(b)	December 31 (a)(b)(c)(d)
2005:				
Coal sales	$ 600,464	$ 633,797	$ 654,716	$ 619,796
Gross profit	29,921	39,582	50,149	2,813
Income (loss) from operations	25,952	21,493	34,177	(3,765)
Net income (loss) available to common shareholders	4,778	1,677	17,129	(1,040)
Basic earnings (loss) per common share(h)	0.08	0.03	0.27	(0.02)
Diluted earnings (loss) per common share(h)	0.07	0.03	0.26	(0.02)

	March 31 (e)(f)	June 30 (e)(f)	September 30 (e)(f)	December 31 (a)(e)(f)(g)
2004:				
Coal sales	$ 403,490	$ 422,778	$ 527,775	$ 553,125
Gross profit	19,689	23,449	36,370	22,692
Income from operations	106,909	24,870	26,335	19,932
Net income available to common shareholders	68,186	9,311	8,979	20,043
Basic earnings per common share(h)	1.27	0.17	0.16	0.33
Diluted earnings per common share(h)	1.14	0.17	0.16	0.32

(a) The Company recognized a gain of $6.3 million on the assignment of its rights and obligations on several parcels of land in West Virginia and a gain of $7.3 million on a dragline sale in the first quarter of 2005, and a gain of $9.0 million on the sale of surface land rights at its Central Appalachian operations in West Virginia in the third quarter of 2005. In the fourth quarter of 2005, the Company recognized a gain of $46.5 million on the sale of a rail spur, rail loadout and an idle office complex, and a gain on the sale of its Central Appalachian operations to Magnum of $7.5 million. During the fourth quarter of 2004, the Company assigned its rights and obligations on a parcel of land to a third party resulting in a gain of $5.8 million. The gains, other than those reflected separately, are reflected in other operating income.

(b) Unrealized losses on sulfur dioxide and coal swaps and options were $1.5 million, $0.5 million, $5.5 million and $12.2 million during the four quarters of 2005, respectively.

(c) In the first and fourth quarters, the Company recognized charges under its performance-contingent phantom stock plans of $9.9 million and $4.5 million, respectively, as a component of selling, general and administrative expense ($9.1 million and $4.5 million, respectively) and cost of coal sales ($0.8 million and $0), respectively.

(d) On October 27, 2005, the Company conducted a precautionary evacuation of its West Elk mine after the Company detected elevated readings of combustion-related gases in an area of the mine where the Company had completed mining activities but had not yet removed all remaining longwall equipment. The Company has successfully controlled the combustion-related gases, reentered and rehabilitated the mine and has taken actions to commence longwall mining which the Company expects to begin late in the first quarter. The Company estimates that the financial impact of idling the mine and fighting the fire during the fourth quarter was $33.3 million in reduced operating profit.

(e) The Company sold the remainder of its investment in Natural Resource Partners in June and October 2004. The Company recognized gains of $89.6 million, $0.3 million, $0.3 million and $1.1 million in the four quarters of 2004, respectively.

(f) During the year ended December 31, 2004, Canyon Fuel, which was accounted for under the equity method through July 31, 2004, began the process of idling its Skyline Mine (the idling process was completed in May 2004), and incurred severance costs of $3.2 million for the year ended December 31, 2004. The Company's share of these costs totals $2.1 million and is reflected in income from equity investments. The impact on the 2004 financial results was a charge of $1.2 million during the first quarter and a charge of $0.9 million in the second quarter.

(g) During 2004, the Company filed a royalty rate reduction request with the Bureau of Land Management ("BLM") for its West Elk mine in Colorado. The BLM notified the Company that it would receive a royalty rate reduction for a specified number of tons representing a retroactive portion for the year totaling $2.7 million. The retroactive portion was recognized as a component of cost of coal sales in the Consolidated Statement of Income.

(h) The sum of the quarterly earnings (loss) per common share amounts may not equal earnings (loss) per common share for the full year because per share amounts are computed independently for each quarter and for the year based on the weighted average number of common shares outstanding during each period.

Arch Coal, Inc. and Subsidiaries

Valuation and Qualifying Accounts

	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Charged to Other Accounts	Deductions(1)	Balance at End of Year
			(In thousands)		
Year ended December 31, 2005					
Reserves deducted from asset accounts					
Other assets — other notes and accounts receivable	$ 3,001	$ 1,345	$ (944)(2)	$ 1,625	$ 1,777
Current assets — supplies and inventory	22,976	(630)	(5,780)(2)	1,231	15,335
Deferred income taxes	163,005	(6,138)	6,296 (4)	—	163,163
Year ended December 31, 2004					
Reserves deducted from asset accounts					
Other assets — other notes and accounts receivable	1,469	570	962 (3)	—	3,001
Current assets — supplies and inventory	18,763	1,746	3,010 (3)	543	22,976
Deferred income taxes	161,113	(265)	2,157 (4)	—	163,005
Year ended December 31, 2003					
Reserves deducted from asset accounts					
Other assets — other notes and accounts receivable	3,894	1,315	—	3,740 (5)	1,469
Current assets — supplies and inventory	17,515	1,583	—	335	18,763
Deferred income taxes	145,603	3,543	11,967 (6)	—	161,113

(1) Reserves utilized, unless otherwise indicated.

(2) Balance upon disposition of central Appalachian operations.

(3) Balance at acquisition date of subsidiaries.

(4) Amount represents the valuation allowance for tax benefits from the exercise of employee stock options. The benefit, net of valuation allowance, was recorded as paid-in capital.

(5) Amount represents state net operating loss carryforwards identified in 2003 which were fully reserved.

(6) Amount includes $1.6 million that was recognized as income upon collection of the related receivable.

Selected Financial Information

	Year Ended December 31,				
	2005 (1)(2)(3)(4)(5)(6)(7)(8)(10)	2004 (8)(9)(10)(11)	2003 (8)(9)(10)(12)	2002 (13)(14)(15)	2001 (16)(17)(18)
	(In thousands, except per share data)				
Statement of Operations Data:					
Coal sales revenue	$ 2,508,773	$ 1,907,168	$ 1,435,488	$ 1,473,558	$ 1,403,370
Income from operations	77,857	178,046	40,371	29,277	62,456
Income (loss) before cumulative effect of accounting change	38,123	113,706	20,340	(2,562)	7,209
Cumulative effect of accounting change	—	—	(3,654)	—	—
Net income (loss)	38,123	113,706	16,686	(2,562)	7,209
Preferred stock dividends	(15,579)	(7,187)	(6,589)	—	—
Net income (loss) available to common stockholders	$ 22,544	$ 106,519	$ 10,097	$ (2,562)	$ 7,209
Basic earnings (loss) per common share before cumulative effect of accounting change	$ 0.35	$ 1.91	$ 0.26	$ (0.05)	$ 0.15
Diluted earnings (loss) per common share before cumulative effect of accounting change	$ 0.35	$ 1.78	$ 0.26	$ (0.05)	$ 0.15
Basic earnings (loss) per common share	$ 0.35	$ 1.91	$ 0.19	$ (0.05)	$ 0.15
Diluted earnings (loss) per common share	$ 0.35	$ 1.78	$ 0.19	$ (0.05)	$ 0.15
Balance Sheet Data:					
Total assets	$ 3,051,440	$ 3,256,535	$ 2,387,649	$ 2,182,808	$ 2,203,559
Working capital	216,376	355,803	237,007	37,799	49,813
Long-term debt, less current maturities	971,755	1,001,323	700,022	740,242	767,355
Other long-term obligations	382,256	800,332	722,954	653,789	625,819
Stockholders' equity	1,184,241	1,079,826	688,035	534,863	570,742
Common Stock Data:					
Dividends per share	$ 0.32	$ 0.2975	$ 0.23	$ 0.23	$ 0.23
Shares outstanding at year-end	71,371	62,858	53,205	52,434	52,353
Cash Flow Data:					
Cash provided by operating activities	$ 254,607	$ 146,728	$ 162,361	$ 176,417	$ 145,661
Depreciation, depletion and amortization	212,301	166,322	158,464	174,752	177,504
Capital expenditures	357,142	292,605	132,427	137,089	123,414
Dividend payments	27,639	24,043	17,481	12,045	11,565
Operating Data:					
Tons sold	140,202	123,060	100,634	106,691	109,455
Tons produced	129,685	115,861	93,966	99,641	104,471
Tons purchased from third parties	11,226	12,572	6,602	8,060	5,569

(1) On December 30, 2005, we completed a reserve swap with Peabody Energy and sold to Peabody a rail spur, rail loadout and an idle office complex, all of which is located in the Powder River Basin for a purchase price of $84.6 million. As a result of the transaction, we recognized a gain of $46.5 million which we recorded as a component of other operating income.

(2) On December 31, 2005, we accepted for conversion 2,724,418 shares of preferred stock, representing approximately 95% of the issued and outstanding preferred stock, pursuant to the terms of a conversion offer. As a result of the conversion offer, we issued an aggregate of 6,534,517 shares of common stock pursuant to the conversion terms of the preferred stock and an aggregate premium of 119,602 shares of common stock. We recognized a preferred stock dividend of $9.5 million as a result of the issuance of the premium of 119,602 shares of common stock.

(3) On December 31, 2005, we sold all of the stock of three subsidiaries and their associated mining operations and coal reserves in Central Appalachia to Magnum Coal Company. As a result of the transaction, we recognized a gain of $7.5 million which we recorded as a component of other operating income.

(4) In December 2005, we settled a dispute with one of our landowners. As a result of the settlement, we recognized an expense of $16.0 million which we recorded as a component of other expenses.

(5) During the year ended December 31, 2005, we recognized gains from land, equipment and facility sales of $28.2 million.

(6) During the year ended December 31, 2005, we recorded expenses of $19.7 million related to changes in fair market value of sulfur dioxide and coal derivatives as a component of other operating income.

(7) On October 27, 2005, we conducted a precautionary evacuation of our West Elk mine after we detected elevated readings of combustion-related gases in an area of the mine where we had completed mining activities but had not yet removed final longwall equipment. We estimate that the financial impact of idling the mine and fighting the fire during the fourth quarter of 2005 was $33.3 million in reduced operating profit.

(8) As discussed in Note 15 to our consolidated financial statements, we recognized expenses under our long-term incentive compensation plans of $19.5 million in 2005, $5.5 million in 2004 and $16.2 million in 2003.

(9) During 2004 and 2003, we sold our investment in Natural Resource Partners in four separate transactions occurring in December 2003 and March, June and October 2004. We recognized a gain of $42.7 million in the fourth quarter of 2003 and an aggregate gain of $91.3 million during 2004.

(10) In connection with our repayment of Arch Western's term loans in 2003, we recognized expenses of $7.7 million in 2005, $8.3 million in 2004 and $4.3 million in 2003 related to the costs resulting from the termination of hedge accounting for interest rate swaps. We also recognized expenses of $0.7 million during 2004 and $4.7 million during 2003 related to early debt extinguishment costs. Additionally, subsequent to the termination of hedge accounting for interest rate swaps, we recognized income of $13.4 million in 2003 related to changes in the market value of the swaps.

(11) During 2004, we assigned our rights and obligations on a parcel of land to a third party resulting in a gain of $5.8 million which we recorded as a component of other operating income.

(12) On January 1, 2003, we adopted FAS 143 resulting in a cumulative effect of accounting change of $3.7 million (net of tax).

(13) During the year ended December 31, 2002, we settled certain coal contracts with a customer that was partially unwinding its coal supply position and desired to buy out of the remaining terms of those contracts. The settlements resulted in a pre-tax gain of $5.6 million which we recorded as a component of other revenues.

(14) We recognized a pre-tax gain of $4.6 million during the year ended December 31, 2002 as a result of a workers' compensation premium adjustment refund from the State of West Virginia. During 1998, we entered into the West Virginia workers' compensation plan at one of our subsidiary operations. The subsidiary paid standard base rates until the West Virginia Division of Workers' Compensation could determine the actual rates based on claims experience. Upon review, the Division of Workers' Compensation refunded $4.6 million in premiums which we recognized as an adjustment to cost of coal sales.

(15) During 2002, we filed a royalty rate reduction request with the BLM for our West Elk mine in Colorado. The BLM notified us that it would receive a royalty rate reduction for a specified number of tons representing a retroactive portion for the year totaling $3.3 million. We recognized the retroactive portion as a component of cost of coal sales. Additionally in 2002, Canyon Fuel was notified by the BLM that it would receive a royalty rate reduction for certain tons mined at its Skyline mine. The rate reduction applies to certain tons mined representing a retroactive refund of $1.1 million. We recorded the retroactive amount as a component of income from equity investments.

(16) At the West Elk underground mine in Gunnison County, Colorado, following the detection of combustion-related gases in a portion of the mine, we idled our operation on January 28, 2000. On July 12, 2000, after controlling the combustion-related gases, we resumed production at the West Elk mine and started to ramp up to normal levels of production. We recognized partial pre-tax insurance settlements of $31.0 million during 2000 and a final pre-tax insurance settlement related to the event of $9.4 million during 2001.

(17) The IRS issued a notice outlining the procedures for obtaining tax refunds on certain excise taxes paid by the industry on export sales tonnage. The notice was the result of a 1998 federal court decision that found such taxes to be unconstitutional. We recorded $12.7 million of pre-tax income related to these excise tax recoveries during 2000. During 2001, we recorded an additional $4.6 million of pre-tax income resulting from additional favorable developments associated with these tax refunds.

(18) We recognized a $7.4 million pre-tax gain during 2001 from a state tax credit covering prior periods.

Corporate Governance and Stockholder Information

Common Stock

Our common stock is listed and traded on the New York Stock Exchange under the symbol "ACI" and also has unlisted trading privileges on the Chicago Stock Exchange. The following table sets forth for each period indicated the dividends paid per common share, the high and low sale prices of our common stock and the closing price of our common stock on the last trading day for each of the quarterly periods indicated.

	2005			
	March 31	June 30	September 30	December 31
Dividends per common share	$ 0.08	$ 0.08	$ 0.08	$ 0.08
High	$ 47.53	$ 55.76	$ 69.93	$ 82.20
Low	$ 33.19	$ 40.30	$ 50.28	$ 60.99
Close	$ 43.01	$ 54.57	$ 67.50	$ 79.50

	2004			
	March 31	June 30	September 30	December 31
Dividends per common share	$ 0.06	$ 0.08	$ 0.08	$ 0.08
High	$ 32.89	$ 36.99	$ 36.93	$ 39.00
Low	$ 26.20	$ 27.73	$ 30.10	$ 31.86
Close	$ 31.39	$ 36.59	$ 35.49	$ 35.54

On March 1, 2006, our common stock closed at $75.65 on the New York Stock Exchange. At that date, there were 9,084 holders of record of our common stock.

Dividends

We paid dividends on our outstanding shares of common stock totaling $20.7 million, or $0.32 per share, in 2005 and $16.9 million, or $0.2975 per share, in 2004. There is no assurance as to the amount or payment of dividends in the future because they are dependent on our future earnings, capital requirements and financial condition.

Code of Business Conduct

We have established a Code of Business Conduct which operates as our code of ethics and which applies to all of our salaried employees, including our chief executive officer, chief financial officer and controller. The Code of Business Conduct is published under "Corporate Governance" in the Investors section of our website at archcoal.com.

Corporate Governance Guidelines

Our Board of Directors has adopted Corporate Governance Guidelines which address various matters pertaining to director selection and duties. The guidelines are published under "Corporate Governance" in the Investors section of our website at archcoal.com.

Committee Charters

Each of the Audit, Personnel & Compensation and Nominating & Corporate Governance Committees of our Board of Directors has adopted and maintains a written charter. Each of these charters is published under “Corporate Governance” in the Investors section of our website at archcoal.com.

Stock Information

Questions by stockholders regarding stockholder records, stock transfers, stock certificates, dividends or other stock inquiries (other than our Dividend Reinvestment and Direct Stock Purchase Plan) should be directed to:

American Stock Transfer & Trust Company
59 Maiden Lane, Plaza Level
New York, New York 10038
(800) 360-4519
amstock.com

Requests for information about our Dividend Reinvestment and Direct Stock Purchase and Sale Plan should be directed to:

American Stock Transfer & Trust Company
P.O. Box 922
Wall Street Station
New York, New York 10269-0560
(877) 390-3073
amstock.com

Independent Auditors

Ernst & Young LLP
190 Carondelet Plaza, Suite 1300
St. Louis, Missouri 63105

Certifications

The most recent certifications by our Chief Executive and Chief Financial Officers pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to our Form 10-K for 2005. We submitted our most recent chief executive officer certification to the New York Stock Exchange on June 10, 2005.

Document Copies

Copies of the above documents and our Annual Report on Form 10-K for the year ended December 31, 2005 are available without charge. Requests for these documents, as well as inquires from stockholders and security analysis, should be directed to:

Investor Relations
Arch Coal, Inc.
One CityPlace Drive, Suite 300
St. Louis, Missouri 63141
(314) 994-2717
archcoal.com

Exhibit 21.1

Subsidiaries of the Company

The following is a complete list of the direct and indirect subsidiaries of Arch Coal, Inc., a Delaware corporation, including their respective states of incorporation or organization, as of March 1, 2006:

Arch Energy Resources, Inc. (Delaware)	100%
Arch Reclamation Services, Inc. (Delaware)	100%
Arch Western Acquisition Corporation (Delaware)	100%
Arch Western Resources, LLC (Delaware)	99%
Arch of Wyoming, LLC (Delaware)	100%
Arch Western Finance LLC (Delaware)	100%
Arch Western Bituminous Group LLC (Delaware)	100%
Canyon Fuel Company, LLC (Delaware)	65%*
Mountain Coal Company, LLC (Delaware)	100%
Thunder Basin Coal Company, L.L.C. (Delaware)	100%
Triton Coal Company, LLC (Delaware)	100%
Ark Land Company (Delaware)	100%
Western Energy Resources, Inc. (Delaware)	100%
Ark Land LT, Inc. (Delaware)	100%
Ark Land WR, Inc. (Delaware)	100%
Allegheny Land Company (Delaware)	100%
Apogee Holdco, Inc. (Delaware)	100%
Arch Coal Sales Company, Inc. (Delaware)	100%
Arch Coal Terminal, Inc. (Delaware)	100%
Arch Receivable Company, LLC (Delaware)	100%
Ashland Terminal, Inc. (Delaware)	100%
Canyon Fuel Company, LLC (Delaware)	35%*
Catenary Coal Holdings, Inc. (Delaware)	100%
Cumberland River Coal Company (Delaware)	100%
Lone Mountain Processing, Inc. (Delaware)	100%
Catenary Holdco, Inc. (Delaware)	100%
Coal-Mac, Inc. (Kentucky)	100%
Energy Development Co. (Iowa)	100%
Hobet Holdco, Inc. (Delaware)	100%
Mingo Logan Coal Company (Delaware)	100%
Mountain Gem Land, Inc. (West Virginia)	100%
Mountain Mining, Inc. (Delaware)	100%
Julian Tipple, Inc. (Delaware)	100%
Mountaineer Land Company (Delaware)	100%
Paint Creek Terminals, Inc. (Delaware)	100%
P.C. Holding, Inc. (Delaware)	100%
Saddleback Hills Coal Company (Delaware)	100%

* Canyon Fuel is listed in two places

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in this Annual Report (Form 10-K) of Arch Coal, Inc, of our reports dated March 1, 2006, with respect to the consolidated financial statements of Arch Coal, Inc., Arch Coal, Inc. management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of Arch Coal, Inc., included in the 2005 Annual Report to Shareholders of Arch Coal, Inc.

Our audits also included the financial statement schedule of Arch Coal, Inc. listed in Item 15. This schedule is the responsibility of Arch Coal Inc.'s management. Our responsibility is to express an opinion based on our audits. In our opinion, as to which the date is March 1, 2006, the financial statement schedule referred to above, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We also consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 No. 333-120781) of Arch Coal, Inc. and in the related Prospectus,

(2) Registration Statements (Form S-8 Nos. 333-30565 and 333-112536) pertaining to the Arch Coal, Inc. 1997 Stock Incentive Plan and in the related Prospectus,

(3) Registration Statement (Form S-8 No. 333-32777) pertaining to the Arch Coal, Inc. Employee Thrift Plan and in the related Prospectus,

(4) Registration Statement (Form S-8 No. 333-68131) pertaining to the Arch Coal, Inc. Deferred Compensation Plan and in the related Prospectus, and

(5) Registration Statements (Form S-8 Nos. 333-112537 and 333-127548) pertaining to the Arch Coal, Inc. Retirement Account Plan,

of our reports dated March 1, 2006, with respect to the consolidated financial statements of Arch Coal, Inc., Arch Coal, Inc. management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of Arch Coal, Inc., incorporated herein by reference and our report included in the preceding paragraph with respect to the financial statement schedule of Arch Coal, Inc. included in this Annual Report (Form 10-K) of Arch Coal, Inc.

/s/ Ernst & Young LLP

St. Louis, Missouri
March 1, 2006

Exhibit 24.1

Power Of Attorney

KNOW ALL PERSONS BY THESE PRESENTS: That each of the undersigned directors and the undersigned director/officer of Arch Coal, Inc., a Delaware corporation ("Arch Coal"), hereby constitutes and appoints Steven F. Leer, and Robert G. Jones, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power to act without the other, to sign Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2005, to be filed with the Securities and Exchange Commission under the provisions of the Securities Exchange Act of 1934, as amended; to file such Annual Report and the exhibits thereto and any and all other documents in connection therewith, including without limitation, amendments thereto, with the Securities and Exchange Commission; and to do and perform any and all other acts and things requisite and necessary to be done in connection with the foregoing as fully as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

DATED: February 23, 2005

/s/ STEVEN F. LEER Steven F. Leer	President, Chief Executive Officer and Director
/s/ JAMES R. BOYD James R. Boyd	Chairman of the Board and Director
/s/ FRANK M. BURKE Frank M. Burke	Director
/s/ JOHN W. EAVES John W. Eaves	Executive Vice President, Chief Operating Officer and Director
/s/ DOUGLAS H. HUNT Douglas H. Hunt	Director
/s/ PATRICIA F. GODLEY Patricia F. Godley	Director
/s/ THOMAS A. LOCKHART Thomas A. Lockhart	Director
/s/ A. MICHAEL PERRY A. Michael Perry	Director
/s/ ROBERT G. POTTER Robert G. Potter	Director
/s/ THEODORE D. SANDS Theodore D. Sands	Director
/s/ WESLEY M. TAYLOR Wesley M. Taylor	Director

Exhibit 31.1

Certification

I, Steven F. Leer, certify that:

1. I have reviewed this annual report on Form 10-K of Arch Coal, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Steven F. Leer

Steven F. Leer
President and Chief Executive Officer

Date: March 14, 2006

Exhibit 31.2

Certification

I, Robert J. Messey, certify that:

1. I have reviewed this annual report on Form 10-K of Arch Coal, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Robert J. Messey

Robert J. Messey
Senior Vice President and Chief
Financial Officer

Date: March 14, 2006

Exhibit 32.1

Certification of Periodic Financial Reports

I, Steven F. Leer, President and Chief Executive Officer of Arch Coal, Inc., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K for the year ended December 31, 2005 (the "Periodic Report") which this statement accompanies fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) information contained in the Periodic Report fairly presents, in all material respects, the financial condition and results of operations of Arch Coal, Inc.

/s/ Steven F. Leer

Steven F. Leer
President and Chief Executive Officer

Date: March 14, 2006

Exhibit 32.2

Certification of Periodic Financial Reports

I, Robert J. Messey, Executive Vice President and Chief Financial Officer of Arch Coal, Inc., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K for the year ended December 31, 2005 (the “Periodic Report”) which this statement accompanies fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) information contained in the Periodic Report fairly presents, in all material respects, the financial condition and results of operations of Arch Coal, Inc.

/s/ Robert J. Messey

Robert J. Messey
Senior Vice President and Chief
Financial Officer

Date: March 14, 2006