

ARCH COAL INC
Form 10-K
March 14, 2006

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**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

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:**

**Common Stock, \$.01 par value
Preferred Share Purchase Rights
5% Perpetual Cumulative Convertible Preferred
Stock**

**New York Stock Exchange
New York Stock Exchange
New York Stock Exchange**

Title of Each Class

Name of Each Exchange On Which Registered

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

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 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

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

Indicate by check mark whether the registrant is 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 Non-Accelerated Filer

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

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.

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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.

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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

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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:

End Use	2003		2004	
	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

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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

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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.

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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

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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.

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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 Contract		Mining Equipment	Transportation	Tons Sold(2)			Assigned Reserves
	Mine(s)(1)	Mine(1)			2003	2004	2005	
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
U = Underground Mine

D = Dragline
L = Loader/Truck

UP = Union Pacific Railroad
CSX = CSX Transportation

S = Shovel/Truck
E = Excavator/Truck
LW = Longwall
C = Continuous Miner
HW = Highwall Miner

BN = Burlington Northern Railroad
NS = Norfolk Southern Railroad

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- (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

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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 plant 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

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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

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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

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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.

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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

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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.,

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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

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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.

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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.

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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 PM_{2.5} 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 PM_{2.5}, 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 SO₂ and NO_x 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 (SO₂) and nitrogen oxides (NO_x) 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 SO₂ and/or NO_x emissions across 28 eastern states and the District of Columbia and, when fully implemented in 2015, CAIR will reduce SO₂ emissions in these states by over 70 percent and NO_x 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 SO₂ and NO_x 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

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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 multi-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

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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.

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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

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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.

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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.

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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.

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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

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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.

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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 plants. 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

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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.

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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

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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.

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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

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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

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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.

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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.

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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;

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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

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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.

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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.

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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 Seminole 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.

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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		Sulfur Content (lbs. per million Btus)					Reserve Control		Mining Method		Past Reserve Estimates	
	Recoverable	Reserves	Proven	Probable	<1.2	1.2-2.5	>2.5	As Received Btu per lb.(1)	Leased	Owned	Surface	Underground	2003
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		Sulfur Content (lbs. per million Btus)					Reserve Control		Mining Method			
	Recoverable	Reserves	Proven	Probable	<1.2	1.2-2.5	>2.5	As Received Btu per lb.(1)	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

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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

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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

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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
	2.54x			1.04x

Ratio of earnings to combined fixed charges and preference dividends(1)

(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

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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.

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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.

Table of Contents**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.

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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).

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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).

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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).

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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.

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

A. Michael Perry

*

Director

Robert G. Potter

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	Signatures	Capacity
	*	Director
	_____ Theodore D. Sands	
	*	Director
	_____ Wesley M. Taylor	
*By:	/s/ Robert G. Jones	
	_____ Robert G. Jones Attorney-in-fact	