ARCH COAL INC
Form 10-K
March 01, 2007

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Form 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2006
Commission file number: 1-13105
(Exact name of registrant as specified in its charter)

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

Registrant s telephone number, including area code: (314) 994-2700
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, $.01 par value	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

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 þ No o

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

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 þ No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer o

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

The aggregate market value of the voting stock held by non-affiliates of the registrant (excluding outstanding shares beneficially owned by directors, officers and treasury shares) as of June 30, 2006 was approximately $4.4 billion.

On February 26, 2007, approximately 142,374,800 shares of the company s common stock, par value $0.01 per share, were outstanding.

Portions of the company s definitive proxy statement for the annual stockholders meeting to be held on April 26, 2007 are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

		Page
PART I		1
ITEM 1.	BUSINESS	1
ITEM 1A.	RISK FACTORS	26
ITEM 1B.	UNRESOLVED STAFF COMMENTS	37
ITEM 2.	PROPERTIES	37
ITEM 3.	LEGAL PROCEEDINGS	40
ITEM 4.	SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS	40
PART II		41
ITEM 5.	MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES	41
ITEM 6.	SELECTED FINANCIAL DATA	44
ITEM 7.	MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	45
ITEM 7A.	QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	69
ITEM 8.	FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA	70
ITEM 9.	CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE	70
ITEM 9A.	CONTROLS AND PROCEDURES	70
ITEM 9B.	OTHER INFORMATION	70
PART III		70
ITEM 10.	DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE	70
ITEM 11.	EXECUTIVE COMPENSATION	71
ITEM 12.	SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS	71
ITEM 13.	CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE	71
ITEM 14.	PRINCIPAL ACCOUNTING FEES AND SERVICES	72
PART IV		72
ITEM 15.	EXHIBITS AND FINANCIAL STATEMENT SCHEDULES	72

State Coal Lease
State Coal Lease
Federal Coal Lease
Form of Non-Qualified Stock Option
Computation of Ratio of Earnings to Combines Fixed Charges
Subsidiaries
Consent of Ernst & Young LLP
Power of Attorney
Certification of Steven F. Leer
Certification of Robert J. Messey
Section 1350 Certification of Steven F. Leer
Section 1350 Certification of Robert J. Messey

Cautionary Statements Regarding Forward-Looking Information

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 statem 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, you should see Risk Factors beginning on page 26.

Table of Contents

Glossary of Selected Mining Terms

Certain terms that we use in this Annual Report on Form 10-K are specific to the coal mining industry and may be technical in nature. The following is a list of selected mining terms and the definitions we attribute to them when we use them throughout this document.

Assigned reserves	Recoverable coal reserves designated for mining by a specific operation.
Btu	A measure of the energy required to raise the temperature of one pound of water one degree of Fahrenheit.
Compliance coal	Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btu, requiring no blending or other sulfur dioxide reduction technologies in order 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 cars in a continuous operation.
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 by cables from the end of a long boom, which is able to scoop up large amounts of overburden as it is dragged across the excavation area and redeposit the overburden in another area.
Longwall mining	One of two major underground coal mining methods, employing a rotating drum pulled mechanically back and forth across a long face of coal.
Low-sulfur coal	Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btu.
Preparation plant	A facility used for crushing, sizing and washing coal to remove impurities and to prepare it for use by a particular customer.
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 or are otherwise less adequately spaced.
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. The process commonly includes recontouring or shaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers.
Recoverable reserves	The amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods and under current law.
Reserves	

	That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.
Room-and-pillar mining	One of two major underground coal mining methods, utilizing continuous miners creating a network of rooms within a coal seam, leaving behind pillars of coal used to support the roof of a mine.
Unassigned reserves	Recoverable coal reserves that have not yet been designated for mining by a specific operation.

PART I

ITEM 1. BUSINESS.

Introduction

We are one of the largest coal producers in the United States. At December 31, 2006, we operated 21 active mines located in each of the three major low sulfur coal-producing regions of the United States. Federal and state regulations controlling air pollution affect the demand for certain types of coal by limiting the amount of sulfur dioxide which may be emitted as a result of fuel combustion. As a result of these regulations, we believe demand for low sulfur coal exceeds demand for other types of coal and often earns a premium in the marketplace. Consequently, we focus on mining, processing and marketing bituminous and sub-bituminous coal with low sulfur content. At December 31, 2006, we estimate that our proven and probable coal reserves had an average heat value of approximately 9,924 Btus and an average sulfur content of approximately 0.60%. Because of these characteristics, we estimate that approximately 79.8% of our proven and probable coal reserves consists of compliance coal.

We sell substantially all of our coal to producers of electric power, steel producers and industrial facilities. For the year ended December 31, 2006, we sold approximately 135.0 million tons of coal, including approximately 10.0 million tons of coal we purchased from third parties, fueling approximately 6% of all electricity generated in the United States. The locations of our mines enable us to ship coal to most of the major coal-fired electric generation facilities in the United States. The following table shows the breakdown of our coal production by region for 2006 and 2005, expressed as a percentage of the total tons produced:

	2006	2005
Powder River Basin	70.7%	65.8%
Western Bituminous	14.2	12.6
Central Appalachia	15.1	21.6
Total	100.0%	100.0%

In 2006, we sold approximately 78.5% of our coal under long-term supply arrangements with a term of more than one year. At December 31, 2006, the average volume-weighted remaining term of our long-term contracts was approximately 4.6 years, with remaining terms ranging from one to 11 years. At December 31, 2006, we had a sales backlog, including a backlog subject to price reopener or extension provisions, of approximately 460.9 million tons.

Despite a slight decline in United States demand for coal in 2006, we expect global and domestic demand for coal to grow over time. Based on industry estimates of future production, we expect demand growth to exert upward pressure on coal pricing in the future. As a result, we have not yet priced a portion of the coal we plan to produce over the next several years in order to take advantage of expected price increases. At December 31, 2006, we had expected production available for repricing of approximately 11 million to 16 million tons in 2007, 75 million to 85 million tons in 2008 and 110 million to 120 million tons in 2009.

Table of Contents

Our History

We were organized in Delaware in 1969 as Arch Mineral Corporation. In July 1997, we merged with Ashland Coal, Inc., a subsidiary of Ashland Oil formed in 1975. As a result of the merger, we became one of the largest producers 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 Colorado and a 65% interest in Canyon Fuel Company, which operates three longwall mines in Utah.

In October 1998, we added to our Powder River Basin reserves when we were the successful bidder for 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 were the successful bidder for the Little Thunder reserve, a 719-million-ton federal reserve tract adjacent to the Black Thunder mine.

At the end of 2005, we sold the stock of Hobet Mining, Apogee Coal Company and Catenary Coal Company and their four associated mining operations (Hobet 21, Arch of West Virginia, Samples and Campbells Creek) and approximately 455.0 million tons of coal reserves in Central Appalachia to Magnum Coal Company, which we refer to as Magnum.

The Coal Industry

Overview. Coal is a combustible, sedimentary, organic rock formed from vegetation that has been consolidated between other rock strata and altered by the combined effects of pressure and heat over millions of years. The degree of change undergone by coal as it matures from peat to anthracite significantly affects its physical and chemical properties. Initially, peat is converted into lignite, a relatively soft material that can range in color from dark black to various shades of brown. The continuing effects of temperature and pressure causes lignite to transform into sub-bituminous coal. Lignite and sub-bituminous coal are typically softer, friable materials characterized by high moisture levels and low carbon content. Because of their carbon content, lignite and sub-bituminous coal generally produce less energy than bituminous, or hard, coal, formed by continuing chemical and physical changes. Under the right conditions, continuing organic maturity can result in anthracite, a hard black rock with a high carbon and energy content and a low level of moisture. According to the World Coal Institute, which we refer to as the WCI, sub-bituminous and bituminous coal comprise approximately 82% of the global coal reserves.

Because of its chemical composition, coal is a major contributor to the global energy supply, providing more than 39% of the world s electricity, according to the WCI. The United States produces approximately 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 data from the Energy Information Administration, which we refer to as the EIA, coal-based power plants generated

Table of Contents

approximately 50% of the electricity produced in the United States in 2006. Coal also represents the lowest cost fossil fuel used for electric power generation. According to the EIA, the average delivered cost of coal to electric power generators during the fourth quarter of 2006 was $1.67/mm Btu, which was $5.67/mm Btu less expensive than residual fuel oil and $5.12/mm Btu less expensive than natural gas.

Compared to other fuels used for electric power generation, coal is domestically available and reliable. Prices for oil and natural gas in the United States have reached record levels in recent years because of tensions regarding international supply and the impact of hurricane interruptions in the Gulf of Mexico in 2005. Historically high oil and natural gas 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, more than 90 gigawatts 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.

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 2006, the two existing rail transportation providers in the Powder River Basin in Wyoming expanded their rail capacity, and a potential third rail transportation provider is advancing with plans to construct additional access to this region. We believe this development further demonstrates the commitment to coal as a future source of fuel for the United States.

Coal is expected to remain the fuel of choice for domestic power generation through at least 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 also expect advances in technologies designed to capture and sequester carbon dioxide emissions. These technologies have garnered greater attention in recent years due to the perceived impact of carbon dioxide on the global climate. We believe these technological 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 electric generation facilities to generate electricity, by steel companies to produce coke for use in blast furnaces and by a variety of industrial users to heat and power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Coal consumption in the United States has increased from 398.1 million tons in 1960 to approximately 1.1 billion tons in 2006, based on information provided by EIA.

Table of Contents

According to the EIA, United States coal consumption by sector for 2006 and 2005 is as follows (tons in millions):

	2006		2005	
End Use	**Tons**	**%**	**Tons**	**%**
Electric generation	1,023.3	92.0%	1,037.5	92.2%
Industrial	61.5	5.5	60.3	5.3
Steel production	23.3	2.1	23.4	2.1
Residential/ Commercial	4.3	0.4	4.2	0.4
Total	1,112.4	100.0%	1,125.4	100.0%

Source: EIA

Coal has long been favored as an electricity generating fuel because of its cost advantage and its availability throughout the United States. According to the EIA, coal accounted for approximately 50% of U.S. electricity generation in 2006 and is projected to account for approximately 57% in 2030, while generation from natural gas is expected to peak in 2020. The largest cost component in electricity generation at natural gas- and coal-fired power plants 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 power plant built today, fuel costs would represent about one-half of total operating costs, whereas the share for a new natural gas-fired power plant would be almost 90%. Other factors that influence an electric generation facility s choice of generation method may include facility cost, fuel transportation infrastructure and environmental restrictions.

Planned new domestic coal-fueled electric generation capacity announcements exceeded 90 gigawatts at December 31, 2006, equating to as much as 300 million tons of additional coal demand annually. We estimate that, at December 31, 2006, approximately 15 gigawatts of generating capacity was under construction or in advanced stages of development with completion expected by 2010, an amount that could translate into as much as 60 million tons of incremental coal demand during that time period. We believe that demand growth from new coal-fueled electric generation facilities represents an important element to the long-term outlook for coal.

Table of Contents

According to the EIA, the breakdown of United States electricity generation by fuel source in 2006 is as follows:

Electricity Generation Mode	%
Coal	50.1%
Nuclear	20.1
Natural gas	19.0
Hydro	7.3
Petroleum and other	3.5
Total	100.0%

Source: EIA

The EIA projects that generators of electricity will increase their demand for coal as demand for electricity increases. The EIA expects coal use for electricity generation to increase by 1.5% per year on average from 2005 to 2030. Coal consumption has generally grown at the pace of electricity growth because coal-fired generation is used in most cases to meet base load requirements. We estimate that coal consumption for power generation declined 0.9% in 2006 as a result of an overall reduction in electricity generation demand. Demand for electricity has historically grown in proportion to the United States economic growth by gross domestic product. In 2006, however, gross domestic product rose by approximately 3.4% according to the U.S. Department of Commerce. According to our estimates, this anomaly of a growing economy and declining coal consumption has occurred only four times since the early 1950s.

Demand for coal is broadly influenced by weather as evidenced by the decline in coal consumption in 2006 in response to very mild weather patterns throughout much of the United States. Weather patterns requiring greater use of heating or air-conditioning translate into greater demand for coal generation. As a result of the mild weather during 2006, coal stockpiles at electric generation facilities totaled 136.0 million tons near the end of 2006, according to the EIA, representing an approximate 47-day supply. In comparison, coal stockpiles totaled 101.1 million tons, or an approximate 35-day supply at December 31, 2005, according to the EIA. We believe that some electric generation facilities may decide to maintain higher coal supplies in order to alleviate the impact of critically low stockpiles such as those experienced at the end of 2005. 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 energy, including natural gas, oil and nuclear energy, and alternative energy sources, such as hydroelectric power.

The other major market for coal is the steel industry. Coal is essential for iron and steel production. According to the WCI, approximately 64% of all steel is produced from iron made in blast furnaces that use coal. The steel industry uses metallurgical coal, which is distinguishable from other types of coal because of its high carbon content, low expansion pressure, low sulfur content and various other chemical attributes. Because of these characteristics, the price offered by steel makers for metallurgical coal is generally higher than the price offered by electric generation facilities for steam coal.

Historically high oil and gas prices and global energy security concerns have increased interest in converting coal into a liquid fuel, a process known as liquefaction. Liquid fuel produced from coal can be refined further to produce transportation fuels and other oil products, such as plastics and solvents. Public and governmental interest in these and other coal-conversion technologies has increased, particularly with the introduction of several legislative initiatives in early 2007. Several projects have begun, including a coal-to-liquids facility proposed by DKRW Advanced Fuels LLC, a company in which we acquired a 25% equity interest during 2006. We believe the advancement of coal-conversion and other technologies represents a positive development for the long-term demand for coal.

U.S. Coal Production. In 2006, total coal production in the United States as estimated by the U.S. Department of Energy was 1.1 billion tons. Production of coal in the United States has increased from 434 million tons in 1960 to approximately 1.1 billion tons in 2006 based on information provided by EIA. According to the EIA, the breakdown of United States coal production by producing region for 2006 and 2005 is as follows (tons in millions):

	2006		2005	
	Tons	**%**	**Tons**	**%**
Western	612.9	52.9%	585.0	51.7%
Appalachia	395.2	34.1	397.3	35.1
Interior(1)	151.4	13.0	149.2	13.2
Total	1,159.5	100.0%	1,131.5	100.0%

Source: EIA

(1) Includes the Illinois Basin

Western region. The western region includes the Powder River Basin and the Western Bituminous region. The Powder River Basin is located in northeastern Wyoming and southeastern Montana. Coal from this region has a very low sulfur content and a low heat value. The price of Powder River Basin coal is generally less than that of coal produced in other regions 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 power generation facilities to 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 low sulfur content and varies in heat value. According to the EIA, coal produced in the western United States increased from 408.3 million tons in 1994 to 612.9 million tons in 2006.

Appalachian region. The Appalachian region is divided into the north, central and southern Appalachian regions. Central Appalachia includes eastern Kentucky, Virginia and southern West Virginia. Coal mined from this region generally has a high heat value and low sulfur content. Northern Appalachia includes Maryland, Ohio, Pennsylvania and northern West Virginia. Coal from this region generally has a high heat value and a high sulfur content. According to the EIA, coal produced in the Appalachian region decreased from 445.4 million tons in 1994 to 395.2 million tons in 2006, primarily as a result of the depletion of economically attractive reserves, permitting issues and increasing costs of production.

Table of Contents

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. Coal from the Illinois basin varies in heat value and has high sulfur content. Despite its high sulfur content, coal from the Illinois basin can generally be used by some electric power generation facilities that have installed pollution control devices, such as scrubbers, to reduce emissions. During 2006, we acquired a $33^{1}/3$% interest in Knight Hawk Holdings, LLC, a coal producer in the Illinois basin. We anticipate that Illinois basin coal will play an increasingly vital role in the United States energy markets in future periods. Other coal-producing states in the interior region include Arkansas, Kansas, Louisiana, Mississippi, Missouri, North Dakota, Oklahoma and Texas. According to the EIA, coal produced in the interior region decreased from 179.9 million tons in 1994 to 151.4 million tons in 2006.

International Coal Production. Coal is imported into the United States, primarily from 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 domestic waterways and water transportation facilities are built for export rather than import of coal. To date, the cost of transporting coal from the coast to interior electric generation facilities via rail has generally proven to be expensive. However, coal imports have demonstrated recent strength due to their competitive pricing, particularly when compared to Appalachian coal. According to the EIA, coal imports increased from 8.9 million tons in 1994 to 36.1 million tons in 2006.

Coal Mining Methods

The geological characteristics of coal reserves largely determine the coal mining method employed. There are two primary methods of mining coal: surface mining and underground mining.

Surface Mining. We use surface mining when coal is found close to the surface. We have included the identity and location of our surface mining operations in the table on page 12. In 2006, approximately 74% of our coal production came from surface mining operations.

Surface mining involves removing overburden (earth and rock covering the coal) with heavy earth-moving equipment, such as draglines, power shovels, excavators and loaders. Once exposed, we drill, fracture and systematically remove the coal using haul trucks or conveyors to transport the coal to a preparation plant or to a unit train loadout facility. After we have removed the coal, we use draglines, power shovels, excavators or loaders to backfill the remaining pits with the overburden removed at the beginning of the process. Once we have replaced the overburden and topsoil, we reestablish vegetation and make other improvements that have local community and environmental benefits.

Table of Contents

The following diagram illustrates a typical surface mining operation:

Underground Mining. We use underground mining methods when coal is located deep beneath the surface. We have included the identity and location of our underground mining operations in the table on page 12. In 2006, approximately 18% of our coal production came from underground mining operations.

Our underground mines are typically operated using one or both of two different techniques: longwall mining and room-and-pillar mining.

Longwall mining involves the full extraction of coal from a section of a coal seam using mechanical shearers. Longwall mining is effective for long rectangular blocks of medium to thick coal seams. Ultimate seam recovery using longwall mining techniques can reach 70%. In longwall mining, we use continuous miners described below to develop access to long rectangular coal seams. Hydraulically-powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, loosening the coal. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion. In 2006, approximately 15% of our coal production came from underground mining operations generally using longwall mining techniques.

Table of Contents

The following diagram illustrates a typical underground mining operation using longwall mining techniques:

Room-and-pillar mining is effective for small blocks of thin coal seams. In room-and-pillar mining, we cut a network of rooms into the coal seam, leaving a series of pillars of coal to support the roof of the mine. We use continuous mining equipment to cut the coal from the mining face and shuttle cars to transport the coal to a conveyor belt for further transportation to the surface. The pillars generated as part of this mining method can constitute up to 40% of the total coal in a seam. Higher seam recovery rates can be achieved if retreat mining is used. In retreat mining, we mine as much coal as possible from the pillars as our workers retreat. We then allow the roof to collapse in a controlled fashion. Once we have completed retreat mining to the mouth of a panel, we generally abandon the mined panel and seal it from the rest of the mine. In 2006, approximately 3% of our coal production came from underground mining operations generally using room-and-pillar mining techniques.

Table of Contents

The following diagram illustrates our typical underground mining operation using room-and-pillar mining techniques:

The remaining 8% of our coal production in 2006 included coal we purchased from third parties at prevailing market rates or pursuant to other contractual arrangements.

Coal Preparation. Coal extracted from the ground, particularly at our underground mining operations, contains impurities, such as rock and dirt, and comes in a variety of different-sized fragments. Each of our mining operations in the Central Appalachia region uses a coal preparation plant located near the mine or connected to the mine by a conveyor. These coal preparation plants allow us to treat the coal we extract from those mines to ensure a consistent quality and to enhance its suitability for particular end-users. In 2006, our preparation plants treated approximately 60% of the coal we produced in the Central Appalachia region. For more information about our preparation plants, you should see the section entitled Our Mining Operations beginning on page 11.

The treatments we employ depend on the properties of the extracted coal and its intended use. To remove impurities, we crush raw coal and separate it into various sizes. For larger pieces of coal, we use dense media separation techniques in which we float coal in a tank containing a liquid of specific gravity. Since coal is lighter than its impurities, it floats, and we can separate it from rock and other sediment. We treat smaller pieces of coal using a number of different methods, including centrifuge and froth flotation devices. A centrifuge spins material very quickly, causing solids and liquids to separate. In a froth flotation system, a froth is produced by blowing air into a water bath containing chemical reagents. This process creates bubbles, which attract to the coal but not other sediment.

Table of Contents

Our Mining Operations

At December 31, 2006, we operated 21 active mines at 12 mining complexes 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 Powder River Basin, the Western Bituminous region and the Central Appalachia 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 map shows the locations of our mining operations:

Table of Contents

The following table provides the location of and a summary of information regarding our mining complexes at December 31, 2006, the total sales associated with these complexes for the years ended December 31, 2004, 2005 and 2006 and the total reserves associated with these complexes at December 31, 2006. The amounts disclosed below for the total cost of property, plant and equipment of each mining complex do not include the costs of the coal reserves that we have assigned to any individual complex:

Mining Complex	**Captive Mines(1)**	**Contract Mines(1)**	**Mining Equipment**	**Railroad**	**Tons Sold(2) 2004**	**2005**	**2006**	**Total Cost of Property, Plant and Equipment at December 31, 2006**	**Assigned Reserves**
					(Million tons)			**($ in millions)**	**(Million tons)**
Powder River Basin:									
Black Thunder	S		D, S	UP/BN	75.1	87.6	92.5	$ 577.2	1,403.2
Coal Creek(3)	S		D, S	UP/BN			3.1	140.4	232.0
Western Bituminous:									
Arch of Wyoming(4)				UP	0.2			23.0	19.7
Dugout Canyon(5)	U		LW, C	UP	3.8	4.9	4.2	105.0	35.6
Skyline(5)(6)	U		LW, C	UP	0.6		1.5	96.3	14.5
Sufco(5)	U		LW, C	UP	7.8	7.5	7.4	178.5	60.5
West Elk	U		LW, C	UP	6.2	5.9	5.0	204.8	66.9
Central Appalachia:									
Coal-Mac	S	U, S	L, E	NS/CSX	2.6	3.2	3.7	138.5	9.9
Cumberland River	S(2), U(2)	U(2)	L, C, HW	NS	1.6	2.3	2.6	110.0	25.6
Lone Mountain	U(3)		C	NS/CSX	2.9	2.6	2.5	162.4	40.0
Mingo Logan	U	U	LW, C	NS	5.1	4.7	4.0	136.9	9.2
Mountain Laurel	U		C	CSX				242.3	131.1
Totals					105.9	118.7	126.5	$ 2,115.3	2,048.2

S	=	Surface mine	D	=	Dragline	UP	=	Union Pacific Railroad

U	=	Underground mine	L	=	Loader/truck	CSX	=	CSX Transportation
			S	=	Shovel/truck	BN	=	Burlington Northern Railroad
			E	=	Excavator/truck	NS	=	Norfolk Southern Railroad
			LW	=	Longwall			
			C	=	Continuous miner			
			HW	=	Highwall miner			

(1) Amounts in parenthesis indicate the number of captive and contract mines at the mining complex at December 31, 2006. 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 1.7 million tons for 2006, 2.2 million tons for 2005 and 2.0 million tons for 2004. We have not

included tons of coal we purchased from third parties that were not processed through our loadout facilities in the amounts shown in the table above.

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. We have not included any information in the table above relating to those complexes.

(3) In 2006, we resumed mining at our Coal Creek mine, which we had idled in 2000.

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

(5) Prior to July 31, 2004, we owned a 65% interest in Canyon Fuel and accounted for it as an equity investment in our financial statements. Prior to July 31, 2004, tons sold by Canyon Fuel 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 in the table above represent 100% of Canyon Fuel s sales volume for all periods presented.

(6) In 2006, we resumed mining at our Skyline complex, which we had idled in 2004.

Powder River Basin. Our operations in the Powder River Basin are located in Wyoming and include two surface mines. During 2006, these mining complexes sold approximately 95.6 million tons of compliance coal to customers in the United States. We control approximately 1.8 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 24,300 acres, with a majority of coal controlled by federal and state leases, as well as a small amount of private fee coal acreage. 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.
Coal Creek	The Coal Creek mine is a surface mining complex located in Campbell County, Wyoming. The mine complex is located on approximately 7,400 acres, with a majority of coal controlled by federal and state leases, and a small amount of private fee coal acreage. The mine currently consists of two active pit areas 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 Burlington Northern and Union Pacific railroads. The loadout facility is capable of loading a 14,000-ton unit train in less than three hours.

Western Bituminous. Our operations in the Western Bituminous region are located in southern Wyoming, Colorado and Utah and include four underground mines and four inactive surface mines. All of the surface mines are in reclamation mode. During 2006, the mining complexes in the Western Bituminous region sold approximately 18.1 million tons of compliance coal to customers in the United States. We control approximately 464.0 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 and bond release. The complex also consists of a mining area called Carbon Basin that has recently begun preliminary development of the surface mining area known as the Elk Mountain mine. The inactive surface mines under reclamation are located on approximately 30,100 acres, with a majority of coal controlled by federal, private and state leases. The Carbon Basin mining area is located on approximately 29,900 acres with a majority of coal controlled by federal, private and state leases. The Arch of Wyoming complex had minimal coal production during 2006 attributable to the development mining at the Elk Mountain mine.
Dugout Canyon	The Dugout Canyon mine is an underground mine located in Carbon County, Utah. The mine is located on approximately 20,000 acres, with a majority of coal controlled by federal and state leases, as well as a small amount of private fee coal acreage. The mine currently consists of a single longwall, two continuous miner sections and one truck loadout facility. We wash a portion of the coal we produce at the Dugout Canyon mine at a 400-ton per hour heavy media vessel preparation plant. All of the production is shipped via the Union Pacific railroad or directly to customers by highway trucks. 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.
Skyline	The Skyline mine is an underground mine located in Carbon and Emery Counties, Utah. The mine is located on approximately 13,300 acres, with a majority of coal controlled by federal leases, as well as a small amount on private and county leases. The mine currently consists of one continuous miner section, a longwall 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.
Sufco	The Sufco mine is an underground mine located in Sevier County, Utah. The mine is located on approximately 29,100 acres, with a majority of coal controlled by federal and state leases, as well as a small amount of private fee coal acreage. The mine currently consists of a single longwall, two continuous miner sections and one loadout facility. All of the coal is shipped raw to customers without preparation plant processing. Coal is shipped via the Union Pacific railroad or delivered directly to customers by highway trucks. The rail loadout facility, located approximately 80 miles from the mine, is capable of loading an 11,000-ton unit

train in less than three hours.

Table of Contents

West Elk	The West Elk mine is an underground mine located in Gunnison County, Colorado. The mine is located on approximately 17,000 acres, with a majority of coal controlled by federal and state leases, as well as a small amount of private fee coal acreage. The mine currently consists of a single longwall, 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.

Central Appalachia. Our operations in the Central Appalachia region are located in southern West Virginia, eastern Kentucky and Virginia and included eleven underground mines and four surface mines at December 31, 2006. During 2006, these operations sold approximately 12.8 million tons of compliance and metallurgical coal to customers in the United States and abroad. Metallurgical coal accounted for 2.0 million tons of total coal sales from these operations in 2006. We control approximately 402.0 million tons of proven and probable coal reserves in Central Appalachia.

Coal-Mac	Coal-Mac is a surface and underground mining complex located in Logan County and Mingo County, West Virginia on approximately 46,800 acres. Coal-Mac utilizes seven production spreads to surface mine and deliver coal to the Ragland or Holden 22 rail loadouts. Coal trucked to the Ragland loadout is direct shipped on the Norfolk Southern railroad. The Ragland loadout is capable of loading 5,000 tons per hour. The Holden 22 loadout includes a preparation plant and rail loadout system. Coal from the surface mine is transported via truck to the plant where it is either directly loaded or cleaned and then shipped on the CSX rail system. 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.
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 16,500 acres, primarily in Kentucky. The complex currently consists of four underground mines (two captive, two 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 in less than four hours.
Lone Mountain	The Lone Mountain complex is an underground operation located in Harlan County, Kentucky and Lee County, Virginia on approximately 21,500 acres. 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 12,500-ton unit train in less than four hours.

Table of Contents

Mingo Logan Ben Creek	The Mingo Logan Ben Creek complex is an underground operation located in Mingo County and Logan County, West Virginia on approximately 21,800 acres. The Mingo Logan Ben Creek complex currently consists of three 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 preparation plant by a second conveyor. The loadout facility is capable of loading a 15,000-ton unit train in less than four hours.
Mountain Laurel	The Mountain Laurel complex is an underground operation that we are developing in Logan County, West Virginia on approximately 29,900 acres. 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 were placed into production in the first and third quarters 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, which was placed into service in the third quarter of 2006, is capable of loading a 15,000-ton unit train in less than four hours.

We also incorporate by reference the information about the operating results of each of our segments for the years ended December 31, 2006, 2005 and 2004 contained in Note 25 Segment Information to our consolidated financial statements beginning on page F-1.

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.

Table of Contents

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 by product type within a given major coal producing region tend to be relatively consistent with each other. The price of coal within a region is influenced by market conditions, mine operating costs, coal quality, transportation costs involved in moving coal from the mine to the point of use and the costs of alternative fuels. In addition to supply and demand factors, the price of coal at the mine is influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. It is generally cheaper to mine coal seams that are thick and located close to the surface than to mine thin underground seams. Within a particular geographic region, underground mining, which is the mining method we use in the Western Bituminous region and also a method we use at certain mines in Central Appalachia, is generally more expensive than surface mining, which is the mining method we use in the Powder River Basin and also for certain of our Central Appalachia mines. This is the case because of the higher capital costs, including costs for construction of extensive ventilation systems, and higher per unit 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, and higher sulfur and higher ash content generally result in lower 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 most of 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 sell coal at a certain price, our centralized marketing group assigns contract shipments to our various mines which can be used to source the coal in the appropriate region.

Long-Term Coal Supply Arrangements

We sell coal both under long-term contracts, the terms of which are more than one year, and on a current market or spot basis with terms of one year or less. In 2006, we sold approximately 78.5% of our coal under long-term supply arrangements. At December 31, 2006, the average volume-weighted remaining term of our long-term contracts was approximately 4.6 years, with remaining terms ranging from one to 11 years.

We expect to sell a significant portion of our coal under long-term supply arrangements. We selectively renew or enter into new long-term supply arrangements when we can do so at prices that we believe are favorable. 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.

Provisions permitting renegotiation or modification of coal sale prices are present in some 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, either we have or our customer has the option to terminate the contract if the parties cannot agree on a new price.

We 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 domestic competitors include Alpha Natural Resources, Inc., CONSOL Energy Inc., Foundation Coal Holdings, Inc., International Coal Group, Inc., James River Coal Company, Massey Energy Company, Magnum Coal Company, Peabody Energy Corp. and Rio Tinto Energy North America. Some of these coal producers are larger than us and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in each of the geographic regions in which we operate. 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 nuclear energy, natural gas, hydropower and petroleum, for steam and electrical power generation. Costs and other factors, such as safety and environmental considerations, relating to these alternative fuels affect the overall demand for coal as a fuel.

Geographic Data

We market our coal principally to electric generation facilities in the United States. Coal sales to foreign customers approximated $162.5 million for 2006, $166.0 million for 2005 and $134.0 million for 2004.

Environmental Matters

Our operations, like operations of other coal companies, are subject to regulation, primarily by federal and state 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 including electrical equipment containing polychlorinated biphenyls, which we refer to as PCBs.

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

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

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

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

The Clean Air Act imposes obligations on the United States Environmental Protection Agency, which we refer to as EPA, and on the states to implement regulatory programs that will lead to the attainment and maintenance of national ambient air quality standards, which we refer to as NAAQS. EPA has promulgated a number of NAAQS for air pollutants that are associated with the combustion of coal, including sulfur dioxide, particulate matter, nitrogen oxides and ozone. Owners of coal-fired power plants and industrial boilers have been required to expend considerable resources in an effort to comply with these standards. As these standards become more stringent in the years ahead, emissions control requirements for new and expanded coal-fired power plants and industrial boilers will continue to become more demanding.

In July 1997, EPA adopted more stringent standards for ozone and particulate matter, which we refer to as PM. EPA adopted what is commonly referred to as the 8-hour ozone standard, established for the first time annual and daily standards for fine PM, or particles that are 2.5 micrometers in diameter (PM2.5), and revised the NAAQS for coarse PM, or particles that are less than 10 micrometers in diameter (PM10). EPA s Phase I and Phase II 8-hour ozone implementation rules were challenged, and in December 2006, the D.C. Circuit Court of Appeals vacated and remanded EPA s Phase I 8-hour ozone implementation rule. Litigation challenging certain EPA designations for PM2.5 non-attainment areas is currently being held in abeyance pending reconsideration by EPA. States having designated non-attainment areas for the 1997 standards are required to submit their state implementation plans for achieving attainment of the 8-hour ozone standards by April 2007 and the PM2.5 standards by April 2008 and are likely to require electric power generators to reduce further sulfur dioxide, nitrogen oxide and particulate matter emissions. The attainment deadlines for 8-hour ozone non-attainment areas range from 2007 to 2012 and for PM2.5 non-attainment areas range from 2010 to 2015.

In September 2006, EPA promulgated final, new PM NAAQS. EPA strengthened the daily PM2.5 standards but retained the annual PM2.5 standards and daily PM10 standards and revoked the annual PM10 standards. The 2006 PM NAAQS are the subject of challenge in the D.C. Circuit Court of Appeals. States having non-attainment areas for the 2006 PM2.5 NAAQS are required to submit their state implementation plans for the 2006 PM2.5 NAAQS by April 2013, and the attainment dates range from 2015 to 2020. With respect to ozone, EPA is currently obligated under a consent decree to sign proposed and final rulemakings concerning any new or revised ozone NAAQS in May 2007 and February 2008, respectively.

In October 1998, 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 NOx SIP Call, Phase I states were required to reduce nitrogen oxide emissions by 2004, and Phase II states are required to reduce nitrogen oxide emissions by 2007. Except for five states (Indiana, Illinois, Kentucky, Michigan and Virginia) that failed to submit their Phase II NOx SIP Call rules, all affected states have adopted and submitted to EPA NOx SIP Call rules. For the five states that did not submit Phase II NOx SIP Call rules, EPA is expected to promulgate a federal implementation plan in February 2008. As a result of any federal and state implementation plans, many electric power generation facilities and large industrial plants have been or will be required to install additional emission control measures.

EPA has also initiated a regional haze program designed to protect and 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, which we refer to as CAVR, that will require certain existing coal-fired power plants to install Best Available Retrofit Technology, which we refer to as BART, to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, and particulate matter. In October 2006, EPA published a final emissions trading rule as an alternative to BART. As a result, individual facilities may not have to install emission controls provided the target emissions reductions are met. In December 2006, the D.C. Circuit Court of Appeals upheld EPA s CAVR, rejecting arguments that EPA s CAVR improperly allows the states covered by EPA s Clean Air Interstate Rule trading program to forgo source-specific emissions control requirements to reduce haze. Regional haze state implementation plans are due in 2008.

New regulations concerning the routine maintenance provisions of the New Source Review program were published in October 2003. These regulations were challenged, and in March 2006, the D.C. Circuit Court of Appeals vacated EPA s rule as contrary to §111(a) (4) of the Clean Air Act. EPA and a utility trade association petitioned the United States Supreme Court for a writ of *certiorari* in November 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. In September 2006, EPA proposed changes to the New Source Review program concerning de-bottlenecking, aggregation, and project netting.

In January 2004, the EPA Administrator announced that EPA would be taking new enforcement actions against utilities for violations of the existing New Source Review requirements, and shortly thereafter, EPA issued enforcement notices to several electric utility companies. Additionally, the U.S. Department of Justice, on behalf of EPA, filed lawsuits against several investor-owned electric utilities for alleged violations of the Clean Air Act. EPA claims that these utilities have failed to obtain permits required under the Clean Air Act for alleged major modifications to their power plants. Some of these lawsuits have been settled, with the owners agreeing to install additional pollution control devices on their coal-fired power plants, and other cases are still pending.

In March 2004, North Carolina submitted to EPA a petition under §126 of the Clean Air Act regarding interstate transport of pollution. In its petition, North Carolina alleges that power plants in 12 southeastern and midwestern states contribute significantly to non-attainment in, and interfere with

Table of Contents

maintenance by, North Carolina with respect to the PM2.5 NAAQS. In addition, North Carolina alleges that power plants in five states contribute significantly to non-attainment in, and interfere with maintenance by, North Carolina with respect to the 8-hour ozone NAAQS. In March 2006, EPA promulgated a final rule denying North Carolina s §126 petition. Following EPA s denial of North Carolina s §126 petition, North Carolina and environmental groups petitioned for review. Depending upon the outcome of the litigation, EPA s response to North Carolina s §126 petition could adversely impact the coal needs of power plants in the affected states. With respect to the international transport of pollution, Canadian cities petitioned EPA in November 2006, under §115 of the Clean Air Act, to require emissions reductions from 150 coal-fired power plants in seven midwestern states. If EPA grants the petition, then the affected plants could be required to reduce emissions.

In March 2005, EPA issued three new rules that will impact coal-fired power plants. The three new rules are (i) the Clean Air Interstate Rule, which we refer to as CAIR, aimed at capping emissions of sulfur dioxide and nitrogen oxides 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, which we refer to as CAMR, aimed at capping and reducing 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 emission allowances to plant operators who need more time to comply with the stricter rules. CAIR requires reductions of sulfur dioxide and/or nitrogen oxide emissions across 28 eastern states and the District of Columbia and, when fully implemented in 2015, CAIR will reduce sulfur dioxide emissions in these states by over 70% and nitrogen oxide emissions by over 60% from 2003 levels. Under CAMR, 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, which we refer to as 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% reduction. All three rules are the subject of ongoing litigation.

CAIR and CAMR state implementation plans were due November 2006. More than 21 states missed the deadline for CAMR state implementation plans. For these states, EPA is expected to promulgate a CAMR federal implementation plan in 2007. More than 23 states have adopted or are in the process of adopting state-specific rules that are more stringent than CAMR.

In December 2005, seven northeastern states (Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont) signed the Regional Greenhouse Gas Initiative agreement, which we refer to as RGGI, calling for a 10% reduction of carbon dioxide emissions by 2019, with compliance to begin January 1, 2009. Maryland has subsequently signed on as a full participant in RGGI. The RGGI final model rule was issued in August 2006, and the participating states are developing their state rules. New York, for example, issued draft rules in December 2006 proposing to auction, as opposed to allocate, 100% of its allowances under RGGI. Climate change developments are also taking place in California. In September 2006, California adopted greenhouse gas legislation requiring that long-term base-load generators must not have greenhouse gas emissions rates greater than that of combined cycle natural gas generators. Rules implementing the new greenhouse gas legislation for investor-owned utilities are expected in February

2007. A trading partnership between RGGI states and California has been announced. These and other state climate change rules will likely require additional controls on coal-based electric power generation facilities and industrial boilers and may even cause some users of coal to switch from coal to a lower carbon fuel. In addition, there are a number of climate change lawsuits alleging nuisance and other theories of liability against various defendants pending in the lower courts. In November 2006, the United States Supreme Court heard oral argument in *Massachusetts v. EPA* on whether EPA has improperly failed to list carbon dioxide as a criteria pollutant. If this litigation results in a court order directing EPA to promulgate a new NAAQS for carbon dioxide, then the market demand for coal could decline.

Other Clean Air Act programs are also applicable to power plants that use our coal. For example, the acid rain control provisions of Title IV of the Clean Air Act require a reduction of sulfur dioxide emissions from power plants. 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 power generation facilities can comply with these requirements by: (i) burning lower sulfur coal, either exclusively or mixed with higher sulfur coal, (ii) installing pollution control devices such as scrubbers, which reduce the emissions from high sulfur coal, (iii) reducing electricity generating levels or (iv) purchasing or trading emissions allowances. Specific emissions sources receive these allowances, which electric utilities and industrial concerns can trade or sell to allow other units to emit higher levels of sulfur dioxide. Each allowance permits its holder to emit one ton of sulfur dioxide.

Other proposed initiatives may have an effect upon coal operations. Several so-called mutli-pollutant bills, which would regulate additional air pollutants, have been proposed by various members of Congress. While the details of all of these proposed initiatives vary, there appears to be a movement toward increased regulation of emissions, including carbon dioxide and mercury.

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 was enacted in June 2006 that imposes new requirements for emergency response plans, notification procedures in the event of accidents, and increased civil penalties for violations of the law.

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

SMCRA also requires us to submit a bond or otherwise financially secure the performance of our reclamation obligations. The earliest a reclamation bond can be completely released is five years after reclamation has been achieved. Federal law and some states impose on mine operators the responsibility for repairing the property or compensating the property owners for damage occurring on the surface of the property as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. In addition, the Abandoned Mine Lands Act, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is $0.35 per ton of coal produced from surface mines and $0.15 per ton of coal produced from underground mines. These amounts will decline to $0.315 and $0.135, respectively, beginning October 2007.

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 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.

Clean Water Act. The federal Clean Water Act prohibits the discharge of pollutants into waters of the United States without a permit and defines each of these terms broadly. The statute affects our mining operations in two distinct ways. First, for any discharge of rock or soil into a topographic feature that might constitute a stream, the U.S. Army Corps of Engineers will require a permit specified under §404 of the Clean Water Act for the placement of such fill material into the stream. The Corps implementation of this program and issuance of this permit has been highly litigated in West Virginia since 1998.

Second, EPA, or states which have been delegated the duty, require a permit specified under §402 of the Clean Water Act for any discharge of water from any site that has been disturbed by the act of mining.

The §402 permit imposes limitations on the composition of the effluent that flows from the site, and requires that water quality standards specified for the receiving stream also be achieved. This requires our mining operations to always observe certain management practices, such as routing all surface water flows through sedimentation structures, before the discharge enters public waters. Depending upon the precise water quality standards that must be achieved, additional treatment of the discharge may also be required.

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.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators 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.

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. You should see the section entitled Contingencies beginning on page 63 for more information about certain litigation pertaining to our permits.

Table of Contents

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. The Bush Administration has also proposed to add polar bears to the list of endangered species. If that proposal should be finalized, then that action could result in regulation of carbon dioxide emissions to address global warming.

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.

Employees

At February 26, 2007, we employed a total of approximately 4,050 persons, approximately 220 of whom are 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 as of February 26, 2007 and their positions and offices during the last five years:

C. Henry Besten, Jr.	Mr. Besten, 58, is our Senior Vice President Strategic Development and has served in such capacity since December 2002. Mr. Besten also served as President of our Arch Energy Resources, Inc. subsidiary from July 1997 to October 2006. 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	Mr. Eaves, 49, is our President and Chief Operating Officer and has served in such capacity since April 2006. Mr. Eaves has also been a director since February 2006. From December 2002 to April 2006, Mr. Eaves served as our Executive Vice President and Chief Operating Officer. 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 also serves on the board of directors of ADA-ES, Inc.
Sheila B. Feldman	Ms. Feldman, 52, 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. On December 17, 2003, Solutia Inc. and its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York.

Robert G. Jones	Mr. Jones, 50, 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.
Paul A. Lang	Mr. Lang, 46, is our Senior Vice President Operations and has served in such capacity since December 2006. Mr. Lang served as President of Western Operations from July 2005 through December 2006 and President and General Manager of Thunder Basin Coal Company, L.L.C. from November 1998 through July 2005.
Steven F. Leer	Mr. Leer, 54, is our Chairman and Chief Executive Officer. Mr. Leer served as our President and Chief Executive Officer from 1992 to April 2006. Mr. Leer also serves on the board of directors of the Norfolk Southern Corporation, USG Corp., the Western Business Roundtable and the University of the Pacific and is chairman of the Coal Industry Advisory Board. Mr. Leer is a past chairman and continues to serve on the board of directors of the Center for Energy and Economic Development, the National Coal Council and the National Mining Association.
Robert J. Messey	Mr. Messey, 61, is our Senior Vice President and Chief Financial Officer and has served in such capacity since December 2000. Mr. Messey also serves on the board of directors of Baldor Electric Company and Stereotaxis, Inc.
David B. Peugh	Mr. Peugh, 52, is our Vice President Business Development and has served in such capacity since 1995.
Deck S. Slone	Mr. Slone, 43, is our Vice President Investor Relations and Public Affairs and has served in such capacity since 2001. Mr. Slone has helped direct our investor relations and public affairs functions since joining us in 1997.
David N. Warnecke	Mr. Warnecke, 51, 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 and Public Affairs. The information on our website is not part of this Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS.

Our business involves certain risks and uncertainties. In addition to the risks and uncertainties described below, we may face other risks and uncertainties, some of which may be unknown to us and some of which we may deem immaterial. If one or more of these risks or uncertainties occur, our business, financial condition or results of operations may be materially and adversely affected.

26

Table of Contents

Risks Related to Our Business

Our profitability and the value of our coal reserves depend upon coal demand by United States electric power generators and other factors beyond our control.

Our results of operations and the value of our coal reserves 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 coal consumption patterns of the United States electric generation industry. According to the EIA, the United States electric generation industry accounts for approximately 92% of domestic coal consumption. Certain factors beyond our control, including those listed below, influence the amount of coal consumed for United States electric power generation:

- the overall demand for electricity, which in turn significantly depends on general economic conditions and summer and winter temperatures in the United States;

- environmental and government regulation, including air emission standards for domestic and foreign coal-fired power plants;

- 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, wind and solar power; and

- technological developments, including the effects of worldwide energy conservation measures.

Demand for our low sulfur coal and the prices we obtain for it will also be affected by the price and availability of high sulfur coal. In some instances, United States electric power generators can use high sulfur coal together with emissions allowances in order to satisfy federal and state air emission standards. In addition, restrictions imposed by federal and state air emission standards may cause some electric power generators to shift from coal to natural gas-fired power plants. A decrease in coal consumption by United States electric power generators could reduce the prices we receive for our coal. Significant decreases in the prices we receive for our coal could have a material adverse effect on our profitability and the value of our coal reserves.

Certain conditions or events beyond our control could negatively impact our coal mining operations, our production or our operating costs.

We conduct coal mining operations in underground mines and at surface mines. Certain factors beyond our control, including those listed below, could disrupt our coal mining operations, reduce our production or increase our operating costs:

- 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; and
- regulatory issues involving the plugging of and mining through oil and gas wells that penetrate the coal seams we mine.

If any of these conditions or events occur, particularly at our Black Thunder mine, our coal mining operations may be disrupted, we could experience a delay or halt of production or our operating costs could increase significantly. In addition, if our insurance coverage 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, diesel fuel or rubber tires could negatively affect our operating costs.

Our coal mining operations use significant amounts of steel, diesel fuel and rubber tires. The costs of roof bolts we use in our underground mining operations depend on the price of scrap steel. We also use significant amounts of diesel fuel and tires for the trucks and other heavy machinery we use, particularly at our Black Thunder mine. A worldwide increase in mining, construction and military activities has caused a shortage of the large rubber tires we use in our mining operations. While we have taken initiatives aimed at extending the useful lives of our rubber tires, including increased driver training, improved road maintenance and reduced driving speeds, we may be unable to obtain a sufficient quantity of rubber tires in the future or at prices which are favorable to us. If the prices of steel, diesel fuel and rubber tires increase, our operating costs could be negatively affected. In addition, if we are unable to procure rubber tires, our coal mining operations may be disrupted or we could experience a delay or halt of production.

Our labor costs could increase if the shortage of skilled coal mining workers continues.

Efficient coal mining using modern techniques and equipment requires skilled workers with experience and proficiency in multiple mining tasks. The resurgence in coal mining activity in recent years has caused a significant tightening of the labor supply. In addition, employee turnover rates in the coal industry have increased during this period as coal producers compete for skilled personnel. Because of the shortage of trained coal miners in recent years, we have operated certain facilities without full staff and have hired novice miners, who are required to be accompanied by experienced workers as a safety precaution. These measures have negatively affected our productivity and our operating costs. If the shortage of experienced labor continues or worsens, our production may be negatively affected or our operating costs could increase.

Table of Contents

Disruptions in the quantities of coal produced by our contract mine operators could impair our ability to fill customer orders or increase our operating costs.

We use independent contractors to mine coal at 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. Disruptions in the quantities of coal produced for us by our contract mine operators could impair our ability to fill our customer orders or require us to purchase coal from other sources in order to satisfy those orders. If we are unable to fill a customer order or if we are required to purchase coal from other sources in order to satisfy a customer order, we could lose existing customers and our operating costs could increase.

Our inability to acquire additional coal reserves or our inability to develop coal reserves in an economically feasible manner may adversely affect our business.

As we mine, we deplete our coal reserves. As a result, our ability to produce coal in the future depends, in part, on our ability to acquire additional coal reserves. We may not be able to obtain replacement reserves when we require them. If available, replacement reserves may not be available at favorable prices, or we may not be capable of mining those reserves at costs that are comparable with our existing coal reserves. Our ability to obtain coal reserves in the future could also be limited by restrictions under our existing or future debt agreements and competition from other coal producers. If we are unable to acquire coal reserves to replace the coal reserves we mine, our future production may decrease significantly and our operating results may be negatively affected.

In addition to the availability of additional coal reserves, our future performance depends on the accuracy with which we estimate the quantity and quality of the coal included within those reserves. We base our estimates of reserve information on engineering, economic and geological data assembled, analyzed and reviewed by internal and third-party engineers and consultants. Certain assumptions and other factors beyond our control, including those listed below, could affect the accuracy of our estimates:

- unexpected geological and mining conditions which may not be fully identified by available exploration data or drill hole density and may differ from our experience 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 federal and state environmental, safety or other regulations.

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 have become increasingly more difficult and expensive to obtain and the application review processes are taking longer to complete and have been subject to more frequent challenges.

Because of these uncertainties, the quantity and quality of the coal we are ultimately able to recover within our coal reserves may differ materially from our estimates. Inaccuracies in our estimates could result in revenue that is lower than we expect or operating costs that are higher than we expect.

A defect in title or the loss of a leasehold interest in certain property could limit our ability to mine our coal reserves or result in significant unanticipated costs.

We conduct a significant part of our coal mining operations on properties that we lease. A title defect or the loss of a lease could adversely affect our ability to mine the associated coal reserves. We may not verify title to our leased properties or associated coal reserves until we have committed to developing those properties or coal reserves. We may not commit to develop property or coal reserves until we have obtained necessary permits and completed exploration. As such, the title to property that we intend to lease or coal reserves that we intend to mine may contain defects prohibiting our ability to conduct mining operations. Similarly, our leasehold interests may be subject to superior property rights of other third parties. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs. In addition, some leases require us to produce a minimum quantity of coal and contain minimum production royalties. Our inability to satisfy those requirements may cause the leasehold interest to terminate.

The availability and reliability of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or 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. Disruptions in transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could impair our ability to supply coal to our customers. As we do not have long-term contracts with transportation providers to ensure consistent and reliable service, decreased performance levels over longer periods of time could cause our customers to look to other sources for their coal needs. In addition, increases in transportation costs, including the price of gasoline and diesel fuel, could make coal a less competitive source of energy when compared to alternative fuels or could make coal produced in one region of the United States less competitive than coal produced in other regions of the United States or abroad. If we experience disruptions in our transportation services or if transportation costs increase significantly and we are unable to find alternative transportation providers, our coal mining operations may be disrupted, we could experience a delay or halt of production or our profitability could decrease significantly.

We may be unable to realize the benefits we expect to occur as a result of acquisitions that we undertake.

We continually seek to expand our operations and coal reserves through acquisitions of other businesses and assets, including leasehold interests. Certain risks, including those listed below, could cause us not to realize the benefits we expect to occur as a result of those acquisitions:

- uncertainties in assessing the value, risks, profitability and liabilities (including environmental liabilities) associated with certain businesses or assets;
- the potential loss of key customers, management and employees of an acquired business;
- the possibility that operating and financial synergies expected to result from an acquisition do not develop;
- problems arising from the integration of an acquired business; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying the rationale for a particular acquisition.

Our profitability depends upon the long-term coal supply agreements we have with our customers. Changes in purchasing patterns in the coal industry could make it difficult for us to extend our existing long-term coal supply agreements or to enter into new agreements in the future.

We sell a substantial portion of our coal under long-term coal supply agreements, which we define as contracts with a term greater than one year. Under these arrangements, we fix the prices of coal shipped during the initial year and may adjust the prices in later years. As a result, at any given time the market prices for similar-quality coal may exceed the prices for coal shipped under these arrangements. Changes in the coal industry may cause some of our customers not to renew, extend or enter into new long-term coal supply agreements with us or to enter into agreements to purchase fewer tons of coal than in the past or on different terms or prices. In addition, uncertainty caused by federal and state regulations, including the Clean Air Act, could deter our customers from entering into long-term coal supply agreements.

Because we sell a substantial portion of our coal production under long-term coal supply agreements, our ability to capitalize on more favorable market prices may be limited. Conversely, at any given time we are subject to fluctuations in market prices for the quantities of coal that we have produced but which we have not committed to sell. As described above under Our profitability and the value of our coal reserves depend upon coal demand by United States electric power generators and other factors beyond our control, the market prices for coal may be volatile and may depend upon factors beyond our control. Our profitability may be adversely affected if we are unable to sell uncommitted production at favorable prices or at all. For more information about our long-term coal supply agreements, you should see Long-Term Coal Supply Arrangements beginning on page 17.

Table of Contents

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

For the year ended December 31, 2006, we derived approximately 25.3% of our total coal revenues from sales to our three largest customers, Tennessee Valley Authority, American Electric Power Company, Inc. and TUCO, Inc., and approximately 52.7% of our total coal revenues from sales to our ten largest customers. At December 31, 2006, we had coal supply agreements with those ten customers that expire at various times from 2007 to 2017. We expect to renew, extend or enter into new long-term coal supply agreements with those and other customers. However, we may be unsuccessful in obtaining long-term coal supply agreements with those customers, and those customers may discontinue purchasing coal from us. If any of those customers, particularly any of our three largest customers, was to significantly reduce the quantities of coal it purchases from us, or if we are unable to sell coal to those customers on terms as favorable to us as the terms under our current long-term coal supply agreements, our profitability could suffer significantly. We have limited protection during adverse economic conditions and may face economic penalties if we are unable to satisfy certain quality specifications under our long-term coal supply agreements.

Our long-term coal supply agreements typically contain *force majeure* provisions allowing the parties to temporarily suspend performance during specified events beyond their control. Most of our long-term coal supply agreements also contain provisions requiring us to deliver coal that satisfies certain quality specifications, such as heat value, sulfur content, ash content, hardness and ash fusion temperature. These provisions in our long-term coal supply agreements could result in negative economic consequences to us, including price adjustments, purchasing replacement coal in a higher-priced open market, the rejection of deliveries or, in the extreme, contract termination. Our profitability may be negatively affected if we are unable to seek protection during adverse economic conditions or if we incur financial or other economic penalties as a result of these provisions of our long-term supply agreements.

The amount of indebtedness we have incurred could significantly affect our business.

At December 31, 2006, we had consolidated indebtedness of approximately $1.2 billion. 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. 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 satisfy our financial obligations or our other liquidity needs. Our ability to satisfy our financial obligations may be adversely affected if we incur additional indebtedness in the future. In addition, the amount of indebtedness we have incurred could have significant consequences to our business, including those listed below:

- 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;

- causing a downgrade in our credit ratings if we incur additional debt or are unable to service our existing debt;
- 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.

We may be unable to comply with restrictions imposed by our credit facilities and other financing arrangements.

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 borrow the full amount under our credit facilities, effect acquisitions or dispositions and incur additional debt and require us to 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.

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and, therefore, 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. We generally reprice these bonds annually, however, they are not cancellable by the surety. Surety bond issuers and holders may increase premiums on 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 required by federal and state law could affect our ability to secure reclamation and coal lease obligations and, therefore, our ability to mine or lease coal. Several factors, including those listed below, could cause us to be unable to maintain or to acquire surety bonds in the future:

- 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

Table of Contents

insufficient borrowing capacity under our revolving credit facility or our receivable securitization facility for additional letters of credit.

Our profitability may be adversely affected if we must satisfy certain below-market contracts with coal we purchase on the open market or with coal we produce at our remaining operations.

We have agreed to guarantee Magnum s obligations to supply coal under certain coal sales contracts that we sold to Magnum, the longest of which extends to the year 2017. In order for the transfer of these coal sales contracts to become effective, the customers must approve the assignments of the contracts to Magnum. At December 31, 2006, one customer had not yet approved these assignments. Until this customer consents, we have agreed to purchase the coal required to satisfy these obligations from Magnum at the same price we charge the customer under the contracts. If Magnum cannot supply the coal required under these coal sales contracts, we would be required to purchase coal on the open market or supply coal from our existing operations in order to satisfy our obligations under these contracts. If we had purchased all of the coal required under these contracts at market prices in effect on December 31, 2006, we would have incurred a loss of approximately $97.1 million related to these contracts.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may adversely affect our business.

Terrorist attacks and threats, escalation of military activity or acts of war have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity. Future terrorist attacks, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions affecting our customers may significantly affect our operations and those of our customers. As a result, we could experience delays or losses in transportation and deliveries of coal to our customers, decreased sales of our coal or extended collections from our customers.

Risks Related to Environmental and Other Regulations

Federal and state regulations impose significant costs on us, and future regulations could increase those costs or limit our ability to produce and sell coal.

Federal and state authorities regulate certain areas, including those listed below, that significantly affect the coal mining industry:

- the discharge of materials into the environment;
- employee health and safety;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- management of materials generated by mining operations;
- surface subsidence from underground mining;
- water pollution;
- statutorily mandated benefits for current and retired coal miners;

Table of Contents

- 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 significant 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 mining operations. We may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. Our profitability may be negatively affected if we incur significant costs and liabilities as a result of these regulations. You should see Environmental Matters beginning on page 18 for more information about the federal and state regulations affecting us.

The possibility exists that new legislation and/or regulations and orders may be adopted that may 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.

Our failure to obtain and renew permits necessary for our mining operations could negatively affect our business.

Mining companies must obtain numerous permits that 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. In addition, 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. The permits may also involve requirements that may be changed or interpreted in a manner which restricts our ability to conduct our mining operations or to do so profitably. An inability to conduct our mining operations pursuant to applicable permits would reduce our production, cash flow and profitability.

If the assumptions underlying our estimates of reclamation and mine closure obligations are inaccurate, our costs could be greater than anticipated.

SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining, as well as most aspects of underground mining. We base our estimates of reclamation and mine closure liabilities on permit requirements and our engineering expertise related to these requirements. Our management and engineers periodically review these estimates. The estimates can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, which we refer to as Statement No. 143, requires us to record these obligations as liabilities at fair value. In estimating fair value, we considered the estimated current costs of reclamation and mine closure and applied inflation rates and a third-party profit, as required by Statement No. 143. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. If actual costs differ from our estimates, our profitability could be negatively affected.

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

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

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

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

To dispose of mining overburden generated by our surface mining operations, we often need to obtain permits to construct and operate valley fills and surface impoundments. Some of these permits are Clean Water Act § 404 permits issued by the Army Corps of Engineers. Two of our operating subsidiaries were identified in an existing lawsuit, which challenged the issuance of such permits and asked that the Corps be ordered to rescind them. Our operating subsidiaries are seeking to intervene in the suit to protect their interests in being allowed to operate under the issued permits and have asked that the claims against them be dismissed. We cannot predict the final outcome 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 beginning on page 63 for more information about the litigation described above.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

At December 31, 2006, we owned or controlled primarily through long-term leases approximately 156,000 acres of coal land in West Virginia, 101,000 acres of coal land in Wyoming, 72,000 acres of coal land in Illinois, 62,000 acres of coal land in Utah, 49,000 acres of coal land in Kentucky, 22,000 acres of coal land in New Mexico and 17,000 acres of coal land in Colorado. In addition, we also owned or controlled through long-term leases smaller parcels of property in Alabama, Indiana, Montana and Texas. We lease approximately 115,000 acres of our coal land from the federal government and approximately 28,000 acres of our coal land from various state governments. These governmental leases have terms expiring between 2007 and 2010 and are subject to readjustment and/or extension and to earlier termination for failure to meeting diligent development requirements. Our Pardee, Levan, Sufco, Cardinal, Holden 22, Mingo Logan, Ragland, Medicine Bow and Seminoe II preparation plants or loadout facilities are located on properties held under leases which expire at varying dates over the next 30 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 beginning on page 1 for more information about our mining operations, mining complexes and transportation facilities.

Our Reserves

We estimate that we owned or controlled approximately 2.9 billion tons of proven and probable recoverable reserves at December 31, 2006. Recoverable reserves include only saleable coal and do not

Table of Contents

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, 2006:

Total Assigned Reserves
(Tons in millions)

	Total Assigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus)			As Received Btu per lb.(1)	Reserve Control		Mining Method		Past Reserve Estimates	
				<1.2	1.2-2.5	>2.5		Leased	Owned	Surface	Under-ground	2004	2005
Wyoming	1,655	1,612	43	1,611	44		8,849	1,639	16	1,655		1,840	1,748
Utah	110	59	51	94	16		11,491	108	2		110	112	108
Colorado	67	52	15	67			11,767	65	2		67	80	74
Central App	216	175	41	59	157		13,021	215	1	74	142	409	243
Illinois													13
Total	2,048	1,898	150	1,831	217		9,526	2,027	21	1,729	319	2,441	2,186

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

Total Unassigned Reserves
(Tons in millions)

	Total Unassigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus)			As Received Btu per lb.(1)	Reserve Control		Mining Method	
				<1.2	1.2-2.5	>2.5		Leased	Owned	Surface	Underground
Wyoming	368	255	113	321	47		9,591	277	91	193	175
Utah	41	17	24	36	5		10,939	40	1		41
Colorado	52	42	10	52			11,579	52			52
Central App	186	132	54	86	57	43	12,521	105	81	48	138
Illinois	220	152	68			220	11,407	36	184	2	218
Total	867	598	269	495	109	263	10,865	510	357	243	624

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

At December 31, 2006, approximately 13.0% 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 2007 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

Table of Contents

payment 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 79.8% consist of compliance coal, or coal which emits 1.2 pounds or less of sulfur dioxide per million Btu upon combustion, while an additional 7.2% 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, 2006 was $1.1 billion, consisting of $119.4 million of prepaid royalties and the $988.3 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.

We leased approximately 58,000 acres of property to other coal operators in 2006. We received royalty income of $5.0 million in 2006 from the mining of approximately 2.4 million tons, $7.1 million in 2005 from the mining of approximately 3.0 million tons and $4.0 million in 2004 from the mining of approximately 2.9 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.

Table of Contents

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

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

We periodically engage third parties to review our reserve estimates. The most recent third-party review of our reserve estimates was conducted by Weir International Mining Consultants in February 2007.

ITEM 3. LEGAL PROCEEDINGS.

You should see Contingencies beginning on page 63 for more information about our pending litigation.

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 2006.

Table of Contents

PART II

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

Market for Registrant s Common Equity and Related Stockholder Matters

Our common stock is listed and traded on the New York Stock Exchange under the symbol ACI . On February 26, 2007, our common stock closed at $31.01 on the New York Stock Exchange. On that date, there were approximately 8,760 holders of record of our common stock.

Holders of our common stock are entitled to receive dividends when they are declared by our board of directors. When dividends are declared on common stock, they are usually paid in mid-March, June, September and December. We paid dividends on our common stock totaling $31.4 million, or $0.22 per share, in 2006 and $20.7 million, or $0.16 per share, in 2005. There is no assurance as to the amount or payment of dividends in the future because they are dependent on our future earnings, capital requirements and financial condition.

The following table sets forth for each period indicated the dividends paid per common share, the high and low sale prices of our common stock and the closing price of our common stock on the last trading day for each of the quarterly periods indicated. The information in the following table has been adjusted to reflect a two-for-one stock split of our common stock in the form of a 100% stock dividend paid on May 15, 2006.

	2006			
	March 31	**June 30**	**September 30**	**December 31**
Dividends per common share	$ 0.04	$ 0.06	$ 0.06	$ 0.06
High	44.15	56.45	44.13	37.03
Low	34.30	37.10	25.88	25.85
Close	37.97	42.37	28.91	30.03

	2005			
	March 31	**June 30**	**September 30**	**December 31**
Dividends per common share	$ 0.04	$ 0.04	$ 0.04	$ 0.04
High	23.77	28.72	34.97	41.10
Low	16.60	20.15	25.14	30.50
Close	21.51	27.24	33.75	39.75

Table of Contents

Stock Price Performance Graph

The following performance graph compares the cumulative total return to stockholders on our common stock with the cumulative total return on three indices: a peer group, the peer group used in our definitive proxy statement for our 2006 Annual Meeting of Stockholders and the Standard & Poor s (S&P) 400 (Midcap) Index. The graph assumes that:

- you invested $100 in Arch Coal common stock and in each index at the closing price on December 31, 2001;
- all dividends were reinvested;
- annual reweighting of the peer groups; and
- you continued to hold your investment through December 31, 2006.

For 2006, our peer group, which we refer to for purposes of the table below as the New Industry Peer Group, consists of CONSOL Energy, Inc., Foundation Coal Holdings, Inc., Massey Energy Company and Peabody Energy Corp. For purposes of preparing the performance graph included in our definitive proxy statement for our 2006 Annual Meeting of Stockholders, our peer group, which we refer to for purposes of the table below as the Old Industry Peer Group, consisted of CONSOL Energy, Inc., Freeport McMoran Copper&Gold, Massey Energy Company, Newmont Mining Corp., Peabody Energy Corp. and Southern Copper Corp. We have updated our peer group to include those companies that we believe are most representative of our industry.

You are cautioned against drawing any conclusions from the data contained in this graph, as past results are not necessarily indicative of future performance. The indices used are included for comparative purposes only and do not indicate an opinion of management that such indices are necessarily an appropriate measure of the relative performance of our stock.

Table of Contents

5-Year Total Stockholder Return
Arch Coal, Inc. v. S&P 400 (Midcap) Index and Industry Peer Groups

	12/31/01	12/31/02	12/31/03	12/31/04	12/31/05	12/31/06
Arch Coal, Inc.	$ 100	$ 96	$ 140	$ 161	$ 363	$ 276
S&P 400 (Midcap)	100	85	116	135	152	168
New Industry Peer Group (4 companies)	100	75	121	213	359	333
Old Industry Peer Group (6 companies)	100	111	201	217	308	331

Issuer Purchases of Equity Securities

The following table summarizes information about shares of our common stock that we purchased during the fourth quarter of 2006.

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, 2006	712,400	$ 28.06	712,400	
Nov. 1 - Nov. 30, 2006				
Dec. 1 - Dec. 31, 2006				
Total	712,400		712,400	$ 385,689,976(2)

(1) In September 2006, our board of directors authorized a share repurchase program for the purchase of up to 14,000,000 shares of our common stock. There is no expiration date on the current authorization, and we have not made any decisions to suspend or cancel purchases under the program.

Table of Contents

As of December 31, 2006, we have purchased 1,562,400 shares of our common stock under this program.

(2) Calculated using 12,437,600 shares of our common stock which we may purchase under the program and $31.01, the closing price of our common stock as reported on the New York Stock Exchange on February 26, 2007.

ITEM 6. SELECTED FINANCIAL DATA.

	Year Ended December 31				
	2006 (1)(2)	2005 (1)(2)(3)(4)	2004 (3)(5)(6)	2003 (3)(6)(7)	2002 (3)
	(Amounts in thousands, except per share data)				
Statement of Operations Data:					
Coal sales revenue	$ 2,500,431	$ 2,508,773	$ 1,907,168	$ 1,435,488	$ 1,473,558
Income from operations	336,667	77,857	178,046	40,371	29,277
Income (loss) before cumulative effect of accounting change	260,931	38,123	113,706	20,340	(2,562)
Cumulative effect of accounting change				(3,654)	
Net income (loss)	260,931	38,123	113,706	16,686	(2,562)
Preferred stock dividends	(378)	(15,579)	(7,187)	(6,589)	
Net income (loss) available to common stockholders	$ 260,553	$ 22,544	$ 106,519	$ 10,097	$ (2,562)
Basic earnings (loss) per common share before cumulative effect of accounting change	$ 1.83	$ 0.18	$ 0.95	$ 0.13	$ (0.02)
Diluted earnings (loss) per common share before cumulative effect of accounting change	1.80	0.17	0.89	0.13	(0.02)
Basic earnings (loss) per common share	1.83	0.18	0.95	0.10	(0.02)
Diluted earnings (loss) per common share	1.80	0.17	0.89	0.10	(0.02)
Balance Sheet Data:					
Total assets	$ 3,320,814	$ 3,051,440	$ 3,256,535	$ 2,387,649	$ 2,182,808
Working capital	46,471	216,376	355,803	237,007	37,799
Long-term debt, less current maturities	1,122,595	971,755	1,001,323	700,022	740,242
Other long-term obligations	391,819	382,256	800,332	722,954	653,789
Stockholders equity	1,365,594	1,184,241	1,079,826	688,035	534,863
Common Stock Data:					
Dividends per share	$ 0.2200	$ 0.1600	$ 0.1488	$ 0.1152	$ 0.1152
Shares outstanding at year-end	142,179	142,741	125,716	106,410	104,868
Cash Flow Data:					
Cash provided by operating activities	$ 308,102	$ 254,607	$ 148,728	$ 162,361	$ 176,417
Depreciation, depletion and amortization	208,354	212,301	166,322	158,464	174,752
Capital expenditures	623,187	357,142	292,605	132,427	137,089
Dividend payments	31,815	27,639	24,043	17,481	12,045

Operating Data:					
Tons sold	134,976	140,202	123,060	100,634	106,691
Tons produced	126,015	129,685	115,861	93,966	99,641
Tons purchased from third parties	10,092	11,226	12,572	6,602	8,060

(1) On October 27, 2005, we conducted a precautionary evacuation of our West Elk mine after we detected elevated readings of combustion-related gases in an area of the mine where we had completed mining activities but had not yet removed final longwall equipment. We estimate that the

idling resulted in $30.0 million in lost profits during the first quarter of 2006, in addition to the effect of the idling and fire-fighting costs incurred during the fourth quarter of 2005 of $33.3 million.

(2) On December 31, 2005, we sold all of the stock of three subsidiaries and their associated mining operations and coal reserves in Central Appalachia to Magnum. As a result of the transaction, we recognized a gain during 2005 of $7.5 million which we recorded as a component of other operating income. In addition, we recognized expenses of $8.7 million during 2006 related to the finalization of working capital adjustments to the purchase price, adjustments to estimated volumes associated with sales contracts acquired by Magnum and expense related to settlement accounting for pension plan withdrawals.

(3) On May 15, 2006, we completed a two-for-one stock split of our common stock in the form of a 100% stock dividend. All share and per share amounts have been retroactively restated for the split.

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

(5) During 2004, we acquired the North Rochelle mine in the Powder River Basin. We also purchased the remaining 35% interest in Canyon Fuel that we did not already own and began consolidating Canyon Fuel in our financial statements as of July 31, 2004.

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

(7) On January 1, 2003, we adopted Statement No. 143 resulting in a cumulative effect of accounting change of $3.7 million (net of tax).

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

Overview

Our three reportable business segments are based on the low-sulfur coal producing regions in the United States in which we operate the Powder River Basin, the Western Bituminous region and the Central Appalachia 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.

Our results for 2006 reflect higher margins driven primarily by increased price realization and the disposition of certain Central Appalachia operations at the end of 2005. We achieved those results despite continued rail challenges in the western United States and weak near-term market conditions. In 2005, we experienced significant disruptions in our rail service from major repair and maintenance work in the Powder River Basin. During 2006, we experienced some shipment disruptions due to ongoing repairs and maintenance on the rail lines, although not of the magnitude experienced in 2005. Our results for 2006 also reflected production at our Coal Creek surface mine in Wyoming, which restarted production in 2006, and Skyline longwall mine in Utah, which commenced mining in a new reserve area in 2006.

Table of Contents

Across all three of our segments, we have committed to sell a large percentage of our coal under sales contracts that we signed in periods when market prices of coal were lower than current market prices. Beginning in 2006 and continuing over the course of the next several years, many of these commitments will expire, and we expect to reprice future coal production at more favorable prices. Abnormal weather patterns, better than expected performance by competing fuels, increased coal production and an increase in utilities coal stockpiles during 2006 resulted in lower consumption by electric power generation facilities. Nevertheless, we believe domestic and global demand growth for coal along with supply pressures, particularly in the Appalachia basin, will cause coal prices to increase. In addition, we expect demand growth from new domestic coal-fueled capacity will also influence future coal consumption and coal prices. At December 31, 2006, we had expected production available for repricing of approximately 11 million to 16 million tons in 2007, 75 million to 85 million tons in 2008 and 110 million to 120 million tons in 2009.

We expect public interest in domestic energy security to accelerate the adoption of coal conversion and other clean-coal technologies. We anticipate that growing legislative support for reducing the geopolitical risks associated with United States oil supplies will cause alternative fuel sources, including liquid fuels generated from coal, to become more significant. We believe that advancement of these technologies represents a positive development for the long-term outlook for coal demand.

Items Affecting Comparability of Reported Results

The comparison of our operating results for the years ended December 31, 2006, 2005 and 2004 is affected by the following significant items:

Sale of select Central Appalachia operations On December 31, 2005, we sold the stock of three subsidiaries and their four associated mining operations and coal reserves in Central Appalachia to Magnum Coal Company. The three subsidiaries were Hobet Mining, Apogee Coal Company and Catenary Coal Company, which included the Hobet 21, Arch of West Virginia, Samples and Campbells Creek mining operations. For the year ended December 31, 2005, these subsidiaries sold 12.7 million tons of coal, had revenues of $509.8 million and incurred a loss from operations of $8.3 million, and for the year ended December 31, 2004, these subsidiaries sold 14.0 million tons of coal, had revenues of $475.1 million and incurred a loss from operations of $3.8 million. We recognized a net gain of $7.5 million in the fourth quarter of 2005 in conjunction with this transaction. The gain we recorded included accrued losses of $65.4 million on firm commitments to purchase coal in 2006 to supply below-market sales contracts, which could no longer be sourced from our operations as a result of the transaction. In addition, we recognized expenses of $8.7 million during 2006 related to the finalization of working capital adjustments to the purchase price, adjustments to estimated volumes associated with sales contracts acquired by Magnum and settlement accounting for pension plan withdrawals. In accordance with the terms of the transaction, we paid $50.2 million to Magnum in 2006 to purchase coal and to offset certain ongoing operating expenses of Magnum. In addition, we were required under the agreement to manage working capital for the operations sold to Magnum for a period of time after the transaction. As of December 31, 2006, we had a current receivable due from Magnum of $8.5 million.

Peabody reserve swap and asset sale On December 30, 2005, we completed a reserve swap with Peabody Energy Corp. and sold to Peabody a rail spur, rail loadout and an idle office complex located in the Powder River Basin for a purchase price of $84.6 million. In the reserve swap, we exchanged 60.0 million tons of coal reserves for a similar block of 60.0 million tons of coal reserves with Peabody in order to facilitate more efficient mine plans for both companies. In conjunction with the transactions, we will continue to lease the rail spur and loadout and office facilities through 2008 while we mine adjacent reserves. We recognized a gain of $46.5 million on the transaction, after the deferral of $7.0 million of the gain, equal to the present value of the lease payments. The deferred gain will be recognized over the term of the lease.

West Elk combustion event The combustion-related event at our West Elk mine in Colorado in October 2005 caused the idling of the mine into the first quarter of 2006. We estimate that the idling resulted in $30.0 million in lost profits during the first quarter of 2006, in addition to the effect of the idling and fire-fighting costs incurred during the fourth quarter of 2005 of $33.3 million. We recognized insurance recoveries related to the event of $41.9 million during the year ended December 31, 2006. We have reflected these insurance recoveries as a reduction of our cost of coal sales for the year ended December 31, 2006. We do not expect to recover any significant additional amounts as a result of this event.

Accounting for pit inventory On January 1, 2006, we adopted the provisions of Emerging Issues Task Force Issue No. 04-6, *Accounting for Stripping Costs in the Mining Industry.* This issue applies to stripping costs incurred in the production phase of a mine for the removal of overburden or waste materials for the purpose of obtaining access to coal that will be extracted. Under the issue, stripping costs incurred during the production phase of the mine are variable production costs that are included in the cost of inventory produced and extracted during the period the stripping costs are incurred. Historically, we recorded stripping costs associated with the tons of coal uncovered and not yet extracted (pit inventory) at our surface mining operations as coal inventory. The cumulative effect of adoption was to reduce inventory by $40.7 million and deferred development cost by $2.0 million with a corresponding decrease to retained earnings, net of tax, of $26.1 million. This accounting change creates volatility in our results of operations, as cost increases or decreases related to fluctuations in pit inventory can only be attributed to tons extracted from the pit. Due to decreases in pit inventory, net income was $10.6 million higher during the year ended December 31, 2006 than it would have been under our previous methodology of accounting for pit inventory.

Sales of interests in Natural Resource Partners L.P. During 2004, we sold our remaining limited partnership units of Natural Resource Partners L.P., resulting in proceeds of approximately $111.4 million and a gain of $91.3 million.

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

Table of Contents

Acquisition of remaining interests of Canyon Fuel On July 31, 2004, we purchased the remaining 35% interest in Canyon Fuel that we did not previously own from ITOCHU Corporation. Since the acquisition, we own all of the ownership interests of Canyon Fuel and consolidate Canyon Fuel in our financial statements. The results of operations of the Canyon Fuel mines are included in our Western Bituminous segment.

Results of Operations

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

The following discussion summarizes our operating results for the year ended December 31, 2006 and compares those results to our operating results for the year ended December 31, 2005.

Revenues. The following table summarizes information about coal sales during the year ended December 31, 2006 and compares those results to the comparable information for the year ended December 31, 2005:

	Year Ended December 31		Increase (Decrease)	
	2006	2005	$	%
	(Amounts in thousands, except per ton data)			
Coal sales	$ 2,500,431	$ 2,508,773	$ (8,342)	(0.3)%
Tons sold	134,976	140,202	(5,226)	(3.7)
Coal sales realization per ton sold	$ 18.53	$ 17.89	$ 0.64	3.6%

Coal sales remained relatively flat during 2006 when compared to 2005. Higher contract prices in all three of our segments partially offset lower volumes resulting primarily from the sale of certain Central Appalachia operations in the fourth quarter of 2005. A higher percentage of Powder River Basin sales, which have a lower average sales price per ton than our other regions, caused the average overall sales price to increase only slightly. We have provided more information about the tons sold and the coal sales prices per ton by operating segment below.

The following table shows the number of tons sold by operating segment during the year ended December 31, 2006 and compares those amounts to the comparable information for the year ended December 31, 2005:

	Tons Sold		Increase (Decrease)	
	2006	2005	Tons	%
	(Amounts in thousands)			
Powder River Basin	96,246	91,471	4,775	5.2%
Western Bituminous	18,122	18,199	(77)	(0.4)
Central Appalachia	20,608	30,532	(9,924)	(32.5)
Total	134,976	140,202	(5,226)	(3.7)%

Sales volume increased in the Powder River Basin as a result of the restart of the Coal Creek mine in the second quarter of 2006 and rail service that improved during 2006 when compared to 2005. In the Western Bituminous region, the effect of an extended longwall move at the Dugout Canyon mine offset a portion of the 1.5 million tons sold from our Skyline mine, which commenced production in a new reserve

Table of Contents

area in the second quarter of 2006. Our volumes in Central Appalachia decreased as a result of the sale of operations to Magnum described previously.

The following table shows the coal sales price per ton by operating segment during the year ended December 31, 2006 and compares those amounts to the comparable information for the year ended December 31, 2005. Coal sales prices per ton exclude certain transportation costs that we pass through to our customers. We use these financial measures because we believe the amounts as adjusted better represent the coal sales prices we achieved within our operating segments. Since other companies may calculate coal sales prices per ton differently, our calculation may not be comparable to similarly titled measures used by those companies. For the year ended December 31, 2006, transportation costs per ton billed to customers were $0.02 for the Powder River Basin, $2.91 for the Western Bituminous region and $1.49 for Central Appalachia. Transportation costs per ton billed to customers for the year ended December 31, 2005 were $0.08 for the Powder River Basin, $3.10 for the Western Bituminous region and $1.48 for Central Appalachia.

	Year Ended December 31		**Increase**	
	2006	**2005**	**$**	**%**
Powder River Basin	$ 10.82	$ 8.20	$ 2.62	32.0%
Western Bituminous	22.42	19.01	3.41	17.9
Central Appalachia	46.90	42.73	4.17	9.8

The increase in our coal sales prices in 2006 resulted from higher contract pricing within all of our segments when compared to 2005, due primarily to the expiration of lower-priced legacy contracts. As discussed previously, we continue to replace sales contracts that we signed in periods when market prices of coal were lower than current market prices. In Central Appalachia, the divestiture described previously of certain operations with lower-priced legacy contracts also helped to improve our average coal sales price per ton.

Expenses, costs and other. The following table summarizes expenses, costs and other operating income and expenses, net for the year ended December 31, 2006 and compares those results to the comparable information for the year ended December 31, 2005:

	Year Ended December 31		**Increase (Decrease) in Net Income**	
	2006	**2005**	**$**	**%**
	(Amounts in thousands)			
Cost of coal sales	$ 1,909,822	$ 2,174,007	$ 264,185	12.2%
Depreciation, depletion and amortization	208,354	212,301	3,947	1.9
Selling, general and administrative expenses	75,388	91,568	16,180	17.7
Gain on sale of Powder River Basin assets		(46,547)	(46,547)	(100.0)
Gain on sale of Central Appalachia operations		(7,528)	(7,528)	(100.0)
Other operating (income) expense, net	(29,800)	7,115	36,915	518.8
Total	$ 2,163,764	$ 2,430,916	$ 267,152	11.0%

Cost of coal sales. Our cost of coal sales decreased from 2005 to 2006 primarily due to the sale of certain Central Appalachia operations described above. This decrease was partially offset by increased sales

Table of Contents

volume, particularly in the Powder River Basin, and higher costs, primarily production taxes and coal royalties, which we pay as a percentage of coal sales. We have provided more information about our operating margins by segment below.

Depreciation, depletion and amortization. The decrease in depreciation, depletion and amortization from 2005 to 2006 is due primarily to the sale of certain Central Appalachia operations described above. Capital improvements associated with development projects largely offset the decrease resulting from the sale of Central Appalachia operations. We have provided additional information concerning our capital spending during 2006 in the section entitled Liquidity and Capital Resources beginning on page 56.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased in 2006 compared to 2005 due primarily to a decrease of $6.7 million related to deferred compensation, a decrease of $8.3 million related to incentive compensation awards, and the establishment of a charitable foundation in 2005 of $5.0 million.

Gain on sale. You should see Items Affecting Comparability of Reported Results beginning on page 46 for more information about the gains on the sale of our Powder River Basin assets and Central Appalachia operations.

Other operating (income) expense, net. The increase in net income in 2006 compared to 2005 from changes in other operating (income) expense is due primarily to the following:

- a decrease of $31.1 million in the amount of realized and unrealized losses associated with sulfur dioxide emission allowance put options and swaps;
- a decrease of $13.9 million in the net expense related to bookouts (the netting of coal sales and purchase contracts with the same counterparty);
- a gain of $10.3 million in 2006 on the acquisition of our interest in Knight Hawk Holdings, LLC;
- an increase of $6.2 million in the amount of income from equity investments; and
- a $16.0 million expense in 2005 related to settlement of certain disputes with a landowner.

These increases in other operating income are partially offset by:

- a decrease of $28.8 million in gains from sales of property, plant and equipment;
- expenses of $8.7 million during 2006 related to the Magnum transaction; and
- a decrease of $4.9 million in the amount of deferred gain associated with the sale of our interest in Natural Resource Partners, L.P., which we recognize over the terms of our leases with Natural Resource Partners L.P., some of which were transferred to Magnum.

Operating margins. Our operating margins (reflected below on a per-ton basis) include all mining costs, which consist of all amounts classified as cost of coal sales (except pass-through transportation costs discussed in Revenues above) and all depreciation, depletion and amortization attributable to mining operations.

	Year Ended December 31		**Increase**	
	2006	**2005**	**$**	**%**
Powder River Basin	$ 2.15	$ 0.95	$ 1.20	126.3%
Western Bituminous	6.86	3.27	3.59	109.8
Central Appalachia	2.95	(0.59)	3.54	600.0

Table of Contents

Powder River Basin On a per-ton basis, operating margins in 2006 increased significantly from 2005 primarily due to the increase in per-ton coal sales realizations discussed previously. The effect of the higher realizations were partially offset by increased production taxes and coal royalties, which we pay as a percentage of coal sales realizations, higher repair and maintenance activity and higher diesel, tire and explosives costs during 2006 compared to 2005.

Western Bituminous Operating margins per ton in 2006 increased from 2005 primarily due to higher per ton sales prices and insurance recoveries related to the West Elk thermal event of $41.9 million, partially offset by higher costs resulting from an extended longwall move at our Dugout Canyon mine, higher coal royalties and production taxes, which we pay as a percentage of sales, and higher repair and supplies costs.

Central Appalachia Operating margins per ton in 2006 increased significantly from 2005 primarily as a result of the sale of certain operations at the end of 2005, discussed previously, which operated at a loss in 2005, and higher coal sales realizations.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2006 and compares that information to the comparable information for the year ended December 31, 2005:

	Year Ended December 31		**Increase (Decrease) in Net Income**	
	2006	**2005**	**$**	**%**
	(Amounts in thousands)			
Interest expense	$ (64,364)	$ (72,409)	$ 8,045	11.1%
Interest income	3,725	9,289	(5,564)	(59.9)
Total	$ (60,639)	$ (63,120)	$ 2,481	3.9%

The decrease in interest expense during 2006 compared to 2005 resulted primarily from an increase in the amounts of interest capitalized in connection with certain major long-term development projects described in more detail in the section entitled Liquidity and Capital Resources beginning on page 56. We capitalized $14.8 million of interest during 2006 and $4.2 million during 2005. The decrease in interest income is due to a decrease in short-term investments, which we liquidated, in part, to fund our capital improvement and development projects. For more information on our ongoing capital improvement and development projects, you should see the section entitled Liquidity and Capital Resources beginning on page 56.

Table of Contents

Other non-operating expense. The following table summarizes our other non-operating expense for the year ended December 31, 2006 and compares that information to the comparable information for the year ended December 31, 2005:

	Year Ended December 31		Increase in Net Income	
	2006	2005	$	%
	(Amounts in thousands)			
Other non-operating expense:				
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	$ (4,836)	$ (7,740)	$ 2,904	37.5%
Other non-operating expense	(2,611)	(3,524)	913	25.9
Total	$ (7,447)	$ (11,264)	$ 3,817	33.9%

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

Income taxes. Our effective tax rate is sensitive to changes in estimates of annual profitability and percentage depletion deductions. The income tax provision of $7.7 million in 2006 compared with the income tax benefit of $34.7 million in 2005 is primarily the result of increases in pre-tax income in 2006, offset by a $49.1 million decrease in our valuation allowance against deferred tax assets in 2006, compared to a $6.1 million decrease in our valuation allowance in 2005.

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

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

Revenues. The following table summarizes information about coal sales during the year ended December 31, 2005 and compares those results to the comparable information for the year ended December 31, 2004:

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

Coal sales. The increase in our coal sales resulted from a combination of increased volumes, higher pricing, and the acquisitions of Triton in the Powder River Basin on August 20, 2004 and the remaining 35% interest in Canyon Fuel in the Western Bituminous region on July 31, 2004. Our per ton realizations increased due primarily to higher contract prices in all three segments. On a consolidated basis, the increase in per ton realization was partially offset by the change in mix of sales volumes among our

operating regions. As reflected in the table below, Central Appalachia volumes (which have the highest average realization) were relatively flat in 2005, while volumes from lower realization regions (the Powder River Basin and Western Bituminous region) increased from 2004.

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

	Tons Sold		Increase	
	2005	2004	Tons	%
	(Amounts in thousands)			
Powder River Basin	91,471	81,857	9,614	11.7%
Western Bituminous	18,199	11,195	7,004	62.6
Central Appalachia	30,532	30,008	524	1.7
Total	140,202	123,060	17,142	13.9%

In 2005, all of our operating segments benefited from an overall increase in demand, while volumes in the Powder River Basin and the Western Bituminous region also benefited from the acquisitions described above compared to 2004.

The following table shows the coal sales price per ton by operating segment during the year ended December 31, 2005 and compares those amounts to the comparable information for the year ended December 31, 2004. Coal sales prices per ton exclude certain transportation costs that we pass through to our customers. We use these financial measures because we believe the amounts as adjusted better represent the coal sales prices we achieved within our operating segments. As other companies may calculate coal sales prices per ton differently, our calculation may not be comparable to similarly titled measures used by those companies. Transportation costs per ton billed to customers for the year ended December 31, 2005 were $0.08 for the Powder River Basin, $3.10 for the Western Bituminous region and $1.48 for Central Appalachia. For the year ended December 31, 2004, transportation costs per ton billed to customers were $0.05 for the Powder River Basin, $2.12 for the Western Bituminous region and $1.46 for Central Appalachia.

	Year Ended December 31		Increase	
	2005	2004	$	%
Powder River Basin	$ 8.20	$ 7.07	$ 1.13	16.0%
Western Bituminous	19.01	15.67	3.34	21.3
Central Appalachia	42.73	36.08	6.65	18.4

In the Powder River Basin, our coal sales prices increased due to higher base pricing and above-market pricing on certain contracts acquired with our Triton acquisition, as well as higher sulfur dioxide quality premiums resulting from an increase in sulfur dioxide emission allowance prices. Our coal sales prices in Central Appalachia increased in 2005, as both contract and spot market prices were higher than in 2004. Additionally, we received higher sales prices on our metallurgical coal sales in 2005 compared to 2004. The Western Bituminous region s coal sales prices increased due to higher contract pricing.

Table of Contents

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

	Year Ended December 31		Increase (Decrease) in Net Income	
	2005	2004	$	%
	(Amounts in thousands)			
Cost of coal sales	$ 2,174,007	$ 1,638,646	$ (535,361)	(32.7)%
Depreciation, depletion and amortization	212,301	166,322	(45,979)	(27.6)
Selling, general and administrative expenses	91,568	57,975	(33,593)	(57.9)
Gain on sale of Powder River Basin assets	(46,547)		46,547	100.0
Gain on sale of Central Appalachia operations	(7,528)		7,528	100.0
Gain on sale of investment in Natural Resource Partners L.P.		(91,268)	(91,268)	(100.0)
Other operating (income) expense, net	7,115	(42,553)	(49,668)	(116.7)
Total	$ 2,430,916	$ 1,729,122	$ (701,794)	(40.6)%

Cost of coal sales. The increase in cost of coal sales is primarily due to the acquisitions of Triton in the Powder River Basin and the remaining 35% interest in Canyon Fuel in the Western Bituminous region, along with an increase in sales-sensitive taxes and royalties and higher diesel fuel, explosives and utilities costs.

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

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

Other operating (income) expense, net. Gains on sales of assets other than those noted above were $28.2 million in 2005, compared to $6.7 million in 2004. This increase was partially offset by the elimination of administrative fees from Canyon Fuel subsequent to our acquisition of the remaining 35% interest during the third quarter of 2004 which resulted in $4.8 million of income in 2004, reduced bookout income, related to the netting of coal sales and purchase contracts with the same counterparty, of $9.4 million compared to the prior year and a $6.5 million decrease in 2005 compared to 2004 of previously-deferred gains from our sales of limited partnership units in Natural Resource Partners L.P. in 2003 and 2004. These deferred gains are being recognized over the terms of our leases with Natural Resource Partners L.P. These increases in other operating income, net were offset by a $16.0 million settlement with a landowner, as well as an expense of $19.7 million recognized to reflect the change in fair value of sulfur dioxide emission allowance swaps and put options and coal swaps which are derivatives but do not qualify for hedge accounting treatment.

Operating margins. Our operating margins (reflected below on a per-ton basis) include all mining costs, which consist of all amounts classified as cost of coal sales (except pass-through transportation costs discussed in Revenues above) and all depreciation, depletion and amortization attributable to mining operations.

	Year Ended December 31		Increase (Decrease)	
	2005	**2004**	**$**	**%**
Powder River Basin	$ 0.95	$ 0.86	$ 0.09	10.5%
Western Bituminous	3.27	0.76	2.51	330.3
Central Appalachia	(0.59)	1.17	(1.76)	(150.4)

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

Western Bituminous On a per-ton basis, higher coal sales prices were partially offset by the effect of the West Elk thermal event discussed under Items Affecting Comparability of Reported Results on page 46.

Central Appalachia On a per-ton basis, higher coal sales prices were partially offset by increased costs for coal purchases, increased labor costs, production taxes and coal royalties, costs for operating supplies and diesel fuel, as well as the increased preparation costs for metallurgical coal discussed above. Additionally, during 2005 our Mingo Logan mine moved into less favorable geological conditions than during 2004, resulting in higher per-ton costs.

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

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

The increase in interest expense results from a higher amount of average borrowings in 2005 as compared to the same period in 2004. In addition, we recognized $1.4 million of interest expense associated with state tax assessments. The increase in interest income resulted primarily from interest on short-term investments.

Table of Contents

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

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

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

Income taxes. Our effective tax rate is sensitive to changes in estimates of annual profitability and percentage depletion. The increase in the income tax benefit of $34.7 million in 2005 as compared to $0.1 million in 2004 is primarily the result of the taxable income from non-mining sources from the sale of the Natural Resource Partners L.P. limited partnership units in the first quarter of 2004. The benefit for 2005 is the result of our taxable income and the effect of percentage depletion on our results.

Liquidity and Capital Resources

Our primary sources of cash include sales of our coal production to customers, borrowings under our credit facilities, sales of assets and debt and equity offerings related to significant transactions. Excluding any significant mineral reserve acquisitions, we generally satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations or borrowings under our credit facilities or accounts receivable securitization program. Our ability to satisfy debt service obligations, to fund planned capital expenditures, to make acquisitions and to pay dividends will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry and financial, business and other factors, some of which are beyond our control.

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

	Year Ended December 31		
	2006	2005	2004
	(Amounts in thousands)		
Cash provided by (used in):			
Operating activities	$ 308,102	$ 254,607	$ 148,728
Investing activities	(688,005)	(291,543)	(597,294)
Financing activities	121,925	(25,730)	517,192

Cash provided by operating activities increased $53.5 million in 2006 compared to 2005 primarily as a result of an increase in net income which was offset by an increased investment in working capital and payments resulting from our sale of certain Central Appalachia operations on December 31, 2005. Specifically, we made payments to Magnum of $50.2 million in 2006 pursuant to the purchase agreement related to that transaction. The payment related to the purchase of coal and certain operating expenses. In addition, at December 31, 2005, we accrued losses of $65.4 million related to commitments to purchase coal in 2006 to satisfy below-market contracts that we could not source from our remaining operations.

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

Cash used in investing activities in 2006 was $396.5 million higher than in 2005, due to increased capital expenditures and the purchase of equity-method investments, as well as a decrease of $116.3 million in proceeds from dispositions of property, plant and equipment. In 2006, we made the second of five annual payments of $122.2 million on the Powder River Basin s Little Thunder federal coal lease, which will continue through 2009. Costs related to the development of the Mountain Laurel complex in West Virginia, higher spending at our Powder River Basin operations related to the restart of the Coal Creek mine and costs related to the purchase of a replacement longwall at the Canyon Fuel operations in the Western Bituminous region resulted in an increase in capital expenditures in 2006 compared to the prior year period. We also spent $40.0 million during 2006 to acquire equity interests in other companies that will be accounted for on the equity method.

We make capital expenditures to improve and replace existing mining equipment, expand existing mines, develop new mines and improve the overall efficiency of mining operations. We anticipate that capital expenditures during 2007 will be between approximately $240 million and $280 million, excluding reserve additions. This estimate includes capital expenditures related to development work at certain of our mining operations, including the Mountain Laurel complex in West Virginia, work on a new loadout at Black Thunder, and the final expenditures for a new longwall at the SUFCO mine. This estimate assumes no other acquisitions, significant expansions of our existing mining operations or additions to our reserve base. In addition to these expenditures, we will make another $122.2 million installment for the Little

Thunder coal lease. We anticipate that we will fund these capital expenditures with available cash, existing credit facilities and cash generated from operations.

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

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

Cash provided by financing activities in 2006 was $121.9 million compared to a use of cash of $25.7 million in 2005. The increase results primarily from borrowings on the revolving credit facility and other credit facilities, including those under the accounts receivable securitization program discussed below, of $192.3 million, compared to net payments of $25.0 million during 2005. The increase in borrowings was to fund our higher capital expenditures, including the Little Thunder federal coal lease noted above. We also had $58.3 million of letters of credit outstanding under the securitization program at December 31, 2006. The average cost of borrowing under the securitization program was approximately 5.36% at December 31, 2006. We had available borrowing capacity of $695.5 million under our credit facilities at December 31, 2006. Financing activities in 2006 also included cash received of $7.0 million from the issuance of common stock under our employee stock incentive plans, a decrease of $24.9 million from 2005. We spent $43.9 million during 2006 under a share repurchase program authorized by the board of directors in September 2006. The program, which replaces a program adopted in 2001, provides for the purchase of up to 14.0 million shares of common stock.

Cash used in financing activities during 2005 consists primarily of net payments on our revolving credit facility of $25.0 million, net payments on our long-term debt of $2.4 million and dividend payments of $27.6 million, offset partially by $31.9 million in proceeds from the issuance of common stock under our employee stock incentive plan. Cash provided by financing activities in 2004 consists primarily of proceeds from the issuance of senior notes of $261.9 million and proceeds from the issuance of common stock through a public offering of $230.5 million described below. Additionally, financing activities in 2004 also include net borrowings under our revolving credit facility of $25.0 million, proceeds of $37.0 million from the issuance of common stock under our employee stock incentive plan and dividend payments of $24.0 million.

Table of Contents

We believe that cash generated from operations, borrowing under our credit facilities, sales of assets and debt and equity offerings will be sufficient to meet working capital requirements, anticipated capital expenditures and scheduled debt payments for at least the next several years.

On June 23, 2006, we amended our credit facility to change the pricing grid upon which the interest rate on borrowings under the credit facility is determined and to extend the maturity date from December 22, 2009 to June 23, 2011. As amended, borrowings under the credit facility bear interest at a floating rate based on LIBOR determined by reference to our leverage ratio, as calculated in accordance with the credit agreement. In addition, the amendment to the credit facility increased the maximum amount of borrowings available to us from $700.0 million to $800.0 million and also revised certain negative covenants and other provisions to provide us with greater flexibility to pursue strategic investments. On October 3, 2006, we entered into a further amendment to the credit facility to eliminate the dollar limitation on the amount of payments we are permitted to make annually with respect to our outstanding capital stock and instead to limit our ability to make those payments by requiring us to comply with certain specified financial ratios, calculated in accordance with the credit agreement, at the time such payments are made. Our credit facility is secured by substantially all of our assets, as well as our ownership interests in substantially all of our subsidiaries, except our ownership interests in Arch Western Resources, LLC and its subsidiaries.

Financial covenants contained in our revolving credit facility consist of a maximum leverage ratio, a maximum senior secured leverage ratio and a minimum interest coverage ratio. The leverage ratio requires that we not permit the ratio of total net debt (as defined in the facility) at the end of any calendar quarter to EBITDA (as defined in the facility) for the four quarters then ended to exceed a specified amount. The interest coverage ratio requires that we not permit the ratio of EBITDA (as defined) at the end of any calendar quarter to interest expense for the four quarters then ended to be less than a specified amount. The senior secured leverage ratio requires that we not permit the ratio of total net senior secured debt (as defined) at the end of any calendar quarter to EBITDA (as defined) for the four quarters then ended to exceed a specified amount. We were in compliance with all financial covenants at December 31, 2006.

On June 23, 2006, we amended our receivable securitization program to increase the program from $100.0 million to $150.0 million and change the fees on amounts funded under the program to rates based on our leverage ratio. Under the terms of the accounts receivable securitization program, eligible trade receivables consist of trade receivables generated by our operating subsidiaries. Although the participants in the program bear the risk of non-payment of purchased receivables, we have agreed to indemnify the participants with respect to various matters. The participants under the program will be entitled to receive payments reflecting a specified discount on amounts funded under the program, including drawings under letters of credit, calculated on the basis of the base rate or commercial paper rate, as applicable. We will pay facility fees, program fees and letter of credit fees (based on amounts of outstanding letters of credit) at rates that vary with our leverage ratio.

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

At December 31, 2006, debt amounted to $1,173.8 million, or 46% of capital employed, compared to $982.4 million, or 45% of capital employed, at December 31, 2005. Based on the level of consolidated indebtedness and prevailing interest rates at December 31, 2006, debt service obligations for 2007, which include the maturities of principal and interest expense, are estimated to be $119.5 million.

We filed a shelf registration statement on Form S-3 with the SEC on March 14, 2006 that allows us to offer and sell from time to time an unlimited amount of unsecured debt securities consisting of notes, debentures, and other debt securities, common stock, preferred stock, warrants, and/or units. Related proceeds could be used for general corporate purposes, including repayment of other debt, capital expenditures, possible acquisitions and any other purposes that may be stated in any prospectus supplement.

On October 28, 2004, we completed a public offering of 14,375,000 shares of our common stock, including the underwriters full over-allotment option, at a price of $16.93 per share. We used the net proceeds of the offering, totaling $230.5 million after the underwriters discount and expenses, to repay borrowings under our revolving credit facility incurred to finance our acquisition of Triton and the first annual payment for the Little Thunder federal coal lease. We used the remaining proceeds for general corporate purposes, including the development of the Mountain Laurel longwall mine in Central Appalachia.

On October 22, 2004, two subsidiaries of Arch Western, as co-obligors, issued $250 million of $6^{3}/4$% senior notes due 2013 at a price of 104.75% of par. The net proceeds of the offering were used to repay and retire the outstanding indebtedness under Arch Western s $100.0 million term loan maturing in 2007, to repay indebtedness under our revolving credit facility and for general corporate purposes.

Ratio of Earnings to Fixed Charges

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

	Year Ended December 31				
	2006	**2005**	**2004**	**2003**	**2002**
Ratio of earnings to combined fixed charges and preference dividends	3.99x	(1)	2.54x	(1)	(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 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 for the year ended December 31, 2005, $2.9 million for the year ended December 31, 2003 and $22.3 million for the year ended December 31, 2002.

Contractual Obligations

The following is a summary of our significant contractual obligations as of December 31, 2006:

	Payments Due by Period				
	2007	**2008-2009**	**2010-2011**	**After 2011**	**Total**
	(Amounts in thousands)				
Long-term debt, including related interest	$ 51,185	$ 8,314	$ 155,400	$ 958,881	$ 1,173,780
Operating leases	28,042	50,015	41,820	19,947	139,824
Royalty leases	149,078	292,629	43,061	21,861	506,629
Unconditional purchase obligations	436,711	84,109			520,820
Total contractual obligations	$ 665,016	$ 435,067	$ 240,281	$ 1,000,689	$ 2,341,053

Royalty leases represent non-cancelable royalty lease agreements, as well as federal lease bonus payments due under the Little Thunder lease. Remaining payments due under the Little Thunder lease will be paid in three equal annual installments of $122.2 million in years 2007 through 2009. Unconditional purchase obligations represent amounts committed for purchases of materials and supplies, payments for services, purchased coal, and capital expenditures.

Our consolidated balance sheet reflects a liability of $216.6 million for the fair value of asset retirement obligations that arise from SMCRA and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. The determination of the fair value of asset retirement obligations involves a number of estimates, as discussed in the section entitled Critical Accounting Policies beginning on page 65, including the timing of payments to satisfy asset retirement obligations. The timing of payments to satisfy asset retirement obligations is based on numerous factors, including mine closure dates. You should see the notes to our consolidated financial statements for more information about our asset retirement obligations.

The table above also excludes certain other obligations reflected in our consolidated balance sheet, including estimated funding for pension and postretirement benefit obligations, for which the timing of payments may vary based on changes in the fair value of plan assets (for pension obligations) and actuarial assumptions and payments under our self-insured workers compensation program. You should see the section entitled Critical Accounting Policies beginning on page 65 for more information about these assumptions. We expect to make contributions of $1.7 million to our pension plans in 2007. You should see the notes to our consolidated financial statements for more information about the amounts we have recorded for workers compensation and pension and postretirement benefit obligations.

Table of Contents

Off-Balance Sheet Arrangements

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

We use a combination of surety bonds, corporate guarantees (e.g., self bonds) and letters of credit to secure our financial obligations for reclamation, workers compensation, postretirement benefits, coal lease obligations and other obligations as follows as of December 31, 2006:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Other	Total
			(Amounts in thousands)		
Self bonding	$ 265,222	$	$	$	$ 265,222
Surety bonds	247,681	33,017	14,700	8,811	304,209
Letters of credit			45,145	14,682	59,827

We have agreed to continue to provide surety bonds and letters of credit for the reclamation, workers compensation and retiree healthcare obligations of the properties we sold to Magnum in order to facilitate an orderly transition. Magnum is required to reimburse us for costs related to the surety bonds and letters of credit until it can replace these items. If the surety bonds and letters of credit related to the reclamation obligations are not replaced by Magnum within two years of the transaction, then Magnum must post a letter of credit in our favor in the amounts of the obligations. Letters of credit related to workers compensation obligations were replaced by Magnum during the fourth quarter of 2006. At December 31, 2006, we had $92.0 million of surety bonds related to properties sold to Magnum.

In addition, we have agreed to guarantee the performance of Magnum with respect to certain coal sales contracts sold to Magnum, the longest of which extends to the year 2017, and certain operating leases, the longest of which ends in 2011. Under the coal sales contracts, the customers must approve the assignment of the contracts to Magnum. Until the contracts are assigned, we are purchasing the coal from Magnum to sell to these customers at the same price it is charging the customers for the sale. One customer agreed to the assignment in the second quarter of 2006, under the agreement that we would continue to guarantee Magnum s performance until the end of 2006. If Magnum is unable to supply the coal for these coal sales contracts, then we would be required to purchase coal on the open market or supply the contract from our existing operations. If we were required to purchase coal to supply the contracts over their duration at market prices effective at December 31, 2006, the cost of the purchased coal would exceed the sales price under the contracts by $97.1 million. If we were required to perform under our guarantee of the operating lease agreements, we would be required to make $15.3 million of lease payments. We believe that it is remote that we would be required to perform under these guarantees. However, if we would have to perform under these guarantees, it could potentially have a material adverse effect on our business, results of operations and financial condition.

In connection with the acquisition of the coal operations of Atlantic Richfield Company, which we refer to as ARCO, and the simultaneous combination of the acquired ARCO operations and our Wyoming operations into the Arch Western joint venture, we agreed to indemnify the other member of Arch

Western against certain tax liabilities in the event that such liabilities arise prior to June 1, 2013 as a result of certain actions taken, including the sale or other disposition of certain properties of Arch Western, the repurchase of certain equity interests in Arch Western by Arch Western or the reduction under certain circumstances of indebtedness incurred by Arch Western in connection with the acquisition. If we were to become liable, the maximum amount of potential future tax payments was $173.7 million at December 31, 2006, of which none is recorded as a liability on our financial statements. Since the indemnification is dependent upon the initiation of activities within our control and we do not intend to initiate such activities, it is remote that we will become liable for any obligation related to this indemnification. However, if such indemnification obligation were to arise, it could potentially have a material adverse effect on our business, results of operations and financial condition.

In addition, tax reporting applied to this transaction by the other member of Arch Western was being audited by the Internal Revenue Service, which we refer to as the IRS. We do not believe that we are bound by the outcome of this audit. Nevertheless, we anticipate that following the conclusion of the audit of the other member, we will soon begin negotiations with the IRS as to adjustments, if any, of Arch Western s tax reporting. The outcome of these negotiations when settled could result in adjustments to the basis of the partnership assets, and it is possible we may be required to adjust our deferred income taxes associated with our investment in Arch Western. Given the uncertainty of how an adverse outcome would affect our deferred income tax position, coupled with potential offsetting tax positions that we may be able to take, we are not able to reasonably determine the resulting outcome of this issue. However, any change that impacts us related to an IRS negotiation may result in a non-cash decrease in deferred income tax assets associated with our investment in Arch Western and could fall within a range of zero to $41.0 million.

Contingencies

Reclamation. SMCRA and similar state statutes require that mine property be restored in accordance with specified standards and an approved reclamation plan. We accrue for the costs of reclamation in accordance with the provisions of Statement No. 143. These costs relate to reclaiming the pit and support acreage at surface mines and sealing portals at underground mines. Other costs of reclamation common to surface and underground mining are related to reclaiming refuse and slurry ponds, eliminating sedimentation and drainage control structures, and dismantling or demolishing equipment or buildings used in mining operations. The establishment of the asset retirement obligation liability is based upon permit requirements and requires various estimates and assumptions, principally associated with costs and productivities.

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

Permit Litigation Matters.

Two of our operating subsidiaries have been identified in an existing lawsuit as having been granted Clean Water Act §404 permits by the Corps allegedly in violation of the Clean Water Act and the National Environmental Policy Act. Surface mines at our Mingo Logan and Coal-Mac mining complexes have been identified in the suit for having received permits from the Corps. The lawsuit, brought by the Ohio Valley Environmental Coalition in the U.S. District Court for the Southern District of

Table of Contents

West Virginia, had originally been filed against the Corps for permits it had issued to coal operations owned by subsidiaries of a company unrelated to us or our operating subsidiaries.

The existing suit claims that the Corps had issued permits to the coal operations belonging to the unrelated company that do not comply with the National Environmental Policy Act and violate the Clean Water Act. At the time the plaintiffs attempted to supplement their complaint to add the permit issued by the Corps to our operating subsidiaries, the lawsuit had been tried to completion and was awaiting a decision by the court. The motions to supplement the complaint and add the newly issued permits name only the Corps as the defendant and ask that the Corps be ordered to rescind the permits.

Our operating subsidiaries are seeking to intervene in the suit to protect their interests in being allowed to operate under the issued permits. They have requested that the court dismiss the motions to supplement as improperly attempting to join the facts and legal theories of our permits with the existing case. Their motions are now before the court for decision.

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

West Virginia Flooding Litigation. We have been served, among others, including a former subsidiary whom we have agreed to defend, in 15 separate complaints filed and served in Wyoming, McDowell, Fayette, Kanawha, Raleigh, Boone and Mercer Counties, West Virginia. These cases collectively include approximately 3,100 plaintiffs who are seeking to recover from more than 180 defendants for property damage and personal injuries arising out of flooding that occurred in southern West Virginia on or about July 8, 2001. The plaintiffs have sued coal, timber, oil and gas, and land companies under the theory that mining, construction of haul roads and removal of timber caused natural surface waters to be diverted in an unnatural way, thereby causing damage to the plaintiffs. The West Virginia Supreme Court has ruled that these cases, along with other flood damage cases not involving us, will be handled pursuant to the court s mass litigation rules. As a result of this ruling, the cases have been transferred to the Circuit Court of Raleigh County in West Virginia to be handled by a panel consisting of three circuit court judges. Trials, by watershed, have begun and are proceeding in phases. On May 2, 2006, the jury returned a verdict concerning certain preliminary matters against the two, non-settling defendants in the first phase of the first watershed, in which we were not involved. We were previously named in cases involving the Coal River watershed. On January 18, 2007, the court dismissed the plaintiffs claims. The plaintiffs have four months from the entry of the order to appeal. We are also named in the Tug Fork and remaining Upper Guyandotte watershed trial groups. These groups will also proceed to trial in phases. A trial date has not yet been set.

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

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

Critical Accounting Policies

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

Asset Retirement Obligations

Our asset retirement obligations arise from SMCRA and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. Significant reclamation activities include reclaiming refuse and slurry ponds, reclaiming the pit and support acreage at surface mines, and sealing portals at deep mines. Our asset retirement obligations are initially recorded at fair value, or the amount at which the obligations could be settled in a current transaction between willing parties. This involves determining the present value of estimated future cash flows on a mine-by-mine basis based upon current permit requirements and various estimates and assumptions, including estimates of disturbed acreage and reclamation costs and assumptions regarding productivity. We estimate disturbed acreage based on approved mining plans and related engineering data. Since we plan to use internal resources to perform reclamation activities, our estimate of reclamation costs involves estimating third-party profit margins, which we base on our historical experience with contractors that perform certain types of reclamation activities. We base productivity assumptions on historical experience with the equipment that we expect to utilize in the reclamation activities. In order to determine fair value, we must also discount our estimates of cash flows to their present value. We base our discount rate on the rates of treasury bonds with maturities similar to expected mine lives, adjusted for our credit standing.

On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, changes in the timing of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Any difference between the actual cost of reclamation and the fair value will be recorded as a gain or loss when the obligation is settled. We expect our actual cost to reclaim our properties will be less than the amount reflected as an asset retirement obligation. At December 31, 2006, we had recorded asset retirement obligation liabilities of $216.6 million, including amounts classified as a current liability. While the precise amount of these future costs cannot be determined with certainty, as of December 31, 2006, we estimate that the aggregate undiscounted cost of final mine closure is approximately $528.4 million.

Table of Contents

Stock-Based Compensation

As of January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment*, which we refer to as Statement No. 123R, which requires all public companies to measure compensation cost in the income statement for all share-based payments (including employee stock options) at fair value. We adopted Statement No. 123R using the modified-prospective method. Under this method, compensation cost for share-based payments to employees is based on their grant-date fair value from the beginning of the fiscal period in which the recognition provisions are first applied. Measurement and recognition of compensation cost for awards that were granted prior to, but not vested as of, the date Statement No. 123R was adopted are based on the same estimate of the grant-date fair value and the same recognition method used previously under Statement No. 123. We use the Black-Scholes option pricing model for options and a lattice model at the grant date for the portion of share-based payments with performance and market conditions that is paid out in stock to determine the fair value. As of December 31, 2006, a $1 increase in our stock price would have resulted in additional expense of $0.1 million for the year ended December 31, 2006.

Derivative Financial Instruments

We use derivative financial instruments to manage exposures to commodity prices and interest rates. Derivative financial instruments are recognized in the balance sheet at fair value. Changes in fair value are recognized in earnings if they are not eligible for hedge accounting or other comprehensive income if they qualify for cash flow hedge accounting. Amounts in other comprehensive income are reclassified to earnings when the hedged transaction affects earnings. Any ineffective portion of a cash flow hedge s change in fair value is recognized immediately in earnings.

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

Employee Benefit Plans

We have non-contributory defined benefit pension plans covering certain of our salaried and hourly employees. Benefits are generally based on the employee s age and compensation. We fund the plans in an amount not less than the minimum statutory funding requirements nor more than the maximum amount that can be deducted for federal income tax purposes. We contributed $19.3 million in cash and stock to the plans during the year ended December 31, 2006 and contributed $20.0 million in cash and stock to the plans during the year ended December 31, 2005. We account for our defined benefit plans in accordance with Statement of Financial Accounting Standards No. 87, *Employer s Accounting for Pensions*, as amended by Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*, which we refer to as Statement No. 87 and Statement No. 158. Statement No. 158 requires that the actuarially-determined funded status of the plans be recorded in the balance sheet, which resulted in an increase to accumulated other comprehensive loss of $11.9 million at December 31, 2006.

In June 2006, the disposition of certain Central Appalachia operations in 2005 resulted in withdrawals that constituted a settlement of our pension benefit obligation for which we recognized expense of $3.2 million.

Table of Contents

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

The expected long-term rate of return on plan assets is an assumption reflecting the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. We establish the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The pension plan s investment targets are 65% equity, 30% fixed income securities and 5% cash. Investments are rebalanced on a periodic basis to stay within these targeted guidelines. The long-term rate of return assumption used to determine pension expense was 8.25% for 2006 and 8.5% 2005. These long-term rate of return assumptions are less than the plan s actual life-to-date returns. Any difference between the actual experience and the assumed experience is recorded in other comprehensive income and amortized into earnings in the future. The impact of lowering the expected long-term rate of return on plan assets 0.5% for 2006 would have been an increase in expense of approximately $1.0 million.

The discount rate represents our estimate of the interest rate at which pension benefits could be effectively settled. Assumed discount rates are used in the measurement of the projected, accumulated and vested benefit obligations and the service and interest cost components of the net periodic pension cost. In estimating that rate, Statement No. 87 requires rates of return on high-quality fixed-income debt instruments. We utilize a bond portfolio model that includes bonds that are rated AA or higher with maturities that match the expected benefit payments under the plan. The discount rate used to determine pension expense was 5.8% for the first six months of 2006 and 6.4% for the last six months of 2006, as a result of a remeasurement of the plan obligation related to the settlement event discussed above, and 6.0% for 2005. The impact of lowering the discount rate 0.5% for 2006 would have been an increase in expense of approximately $1.4 million.

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

For the measurement of our year-end pension obligation for 2006 (and pension expense for 2007), we increased our long-term rate of return assumption from 8.25% to 8.50% and changed our discount rate to 5.90%.

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

Statement No. 158. Statement No. 158 requires that the actuarially-determined funded status of the plans be recorded in the balance sheet.

In 2005, the disposition of the Central Appalachia operations to Magnum constituted a settlement of our postretirement benefit obligation for which we recognized a loss of $59.2 million. The only remaining participants in the postretirement benefit plan have their benefits capped at current levels.

Actuarial assumptions are required to determine the amounts reported as obligations and costs related to the postretirement benefit plan. The discount rate assumption reflects the rates available on high-quality fixed-income debt instruments at year-end and is calculated in the same manner as discussed above for the pension plan. The discount rate used to calculate the postretirement benefit expense was 5.8% for 2006 and 6.0% for 2005. Had the discount rate been lowered by 0.5% in 2006, we would have incurred additional expense of $0.9 million.

For the measurement of our year-end other postretirement obligation for 2006 and postretirement expense for 2007, we changed our discount rate to 5.9%. Because postretirement costs for remaining participants are capped at current levels, future changes in healthcare costs have no future effect on the plan benefits.

On December 31, 2006, we adopted Statement No. 158, which requires that an employer recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its balance sheet and to recognize changes in the funded status though comprehensive income when they occur.

Income Taxes

We provide for deferred income taxes for temporary differences arising from differences between the financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates expected to be in effect when the related taxes are expected to be paid or recovered. A valuation allowance may be recorded to reflect the amount of future tax benefits that management believes are not likely to be realized. In determining the appropriate valuation allowance, we take into account expected future taxable income and available tax planning strategies. If future taxable income is lower than expected or if expected tax planning strategies are not available as anticipated, we may record additional valuation allowance through income tax expense in the period such determination is made.

Accounting Standards Issued and Not Yet Adopted

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, which we refer to as FIN 48. FIN 48 prescribes a recognition threshold and measurement attributes for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. While we expect there will be some impact of recognizing tax positions previously unrecognized under Statement of Financial Accounting Standards No. 5, *Accounting for Contingencies*, we are still analyzing FIN 48 to determine what the impact of adoption will be as of the implementation date of January 1, 2007.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*, which we refer to as Statement No. 157. Statement No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Statement No. 157 applies under other accounting pronouncements that require or permit fair value measurements.

Statement No. 157 is effective prospectively for fiscal years beginning after November 15, 2007, and interim periods within that fiscal year. We are still analyzing Statement No. 157 to determine what the impact of adoption will be.

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

We manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements, rather than through the use of derivative instruments. At December 31, 2006, based on current expectations of production over the next three years, we expect production available for repricing of approximately 11 million to 16 million tons in 2007, 75 million to 85 million tons in 2008 and 110 million to 120 million tons in 2009.

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

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

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At December 31, 2006, substantially all of our outstanding debt bore interest at fixed rates. In the past, we have utilized interest rate swap agreements to modify the interest characteristics of our floating-rate debt. We had no swaps outstanding as of December 31, 2006.

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

With respect to our sulfur dioxide emission allowance put option and swap positions, as well as our heating oil swap positions, a change in price of the underlying products impacts our net financial instrument position. At December 31, 2006, a $100 decrease in the price of sulfur dioxide emission allowances would result in a $0.4 million increase in the fair value of the financial position of our sulfur dioxide emission

Table of Contents

allowance put option and swap agreements, and a $100 increase would result in a $0.2 million increase in the fair value of the call options. At December 31, 2006, a $0.05 per gallon increase in the price of heating oil would result in a $0.9 million increase in the fair value of the financial position of our heating oil swap agreements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements and consolidated financial statement schedule of Arch Coal, Inc. and subsidiaries are included in this Annual Report on Form 10-K beginning on page F-1.

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, 2006. 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, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We incorporate by reference the report of independent registered public accounting firm and management s report on internal control over financial reporting included on pages F-2 and F-5, respectively, of this Annual Report on Form 10-K.

Item 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

We incorporate by reference the information under the heading Code of Conduct appearing in the section entitled Corporate Governance, the information under the headings Nominees for a Three-Year Term That Will Expire in 2010, Directors Whose Terms Will Expire in 2008, Directors Whose Term Will Expire in 2009 and Board Meetings and Committees Audit Committee appearing in the section entitled Election of Directors and the information appearing under the heading Section 16(a) Beneficial Ownership Reporting Compliance appearing in the section entitled Ownership of Arch Coal Common Stock in our proxy statement to be distributed to stockholders in connection with the 2007 annual meeting. You should also see the list of our executive officers and related information under Executive Officers beginning on page 25.

We submitted our most recent chief executive officer certification to the New York Stock Exchange on May 1, 2006.

Table of Contents

ITEM 11. EXECUTIVE COMPENSATION.

We incorporate by reference the information under the heading Director Compensation appearing in the section entitled Election of Directors and the information under the headings Compensation Discussion and Analysis, Summary Compensation Table, Grants of Plan-Based Awards for the Year Ended December 31, 2006, Outstanding Equity Awards at December 31, 2006, Option Exercises and Stock Vested for the Year Ended December 31, 2006, Pension Benefits, Nonqualified Deferred Compensation and Potential Payments Upon Termination of Employment or Change-in-Control appearing in the section entitled Compensation of Executive Officers in our proxy statement to be distributed to stockholders in connection with the 2007 annual meeting.

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

We incorporate by reference the information appearing under the headings Ownership by Directors and Executive Officers and Ownership by Others appearing in the section entitled Ownership of Arch Coal Common Stock in our proxy statement to be distributed to stockholders in connection with the 2007 annual meeting.

Securities Authorized for Issuance Under Equity Compensation Plans

The Arch Coal, Inc. 1997 Stock Incentive Plan, which has been approved by our stockholders, is the sole plan under which we are authorized to issue shares of our common stock to employees. The following table shows the number of shares of common stock to be issued upon exercise of options outstanding at December 31, 2006, the weighted average exercise price of those options, and the number of shares of common stock remaining available for future issuance at December 31, 2006, excluding shares to be issued upon exercise of outstanding options. No warrants or rights had been issued under the plan as of December 31, 2006.

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	2,273,200	$ 10.5816	5,219,092
Equity compensation plans not approved by security holders			
Total	2,273,200	$ 10.5816	5,219,092

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

We incorporate by reference the information under the headings Overview and Director Independence appearing in the section entitled Corporate Governance in our proxy statement to be distributed to stockholders in connection with the 2007 annual meeting.

Table of Contents

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

We incorporate by reference the information under the heading Independent Registered Public Accounting Firm appearing in the section entitled Additional Information in our proxy statement to be distributed to stockholders in connection with the 2007 annual meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The consolidated financial statements and consolidated financial statement schedule of Arch Coal, Inc. and subsidiaries are included in this Annual Report on Form 10-K beginning on page F-1.

You should see the exhibit index for a list of exhibits included in this Annual Report on Form 10-K.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Index to Consolidated Financial Statements

Reports of Independent Registered Public Accounting Firm	F-2
Management s Report on Internal Control over Financial Reporting	F-5
Report of Management	F-6
Consolidated Statements of Income for the Years Ended December 31, 2006, 2005 and 2004	F-7
Consolidated Balance Sheets at December 31, 2006 and 2005	F-8
Consolidated Statements of Stockholders Equity for the Years Ended December 31, 2006, 2005 and 2004	F-9
Consolidated Statements of Cash Flows for the Years Ended December 31, 2006, 2005 and 2004	F-10
Notes to Consolidated Financial Statements	F-11
Financial Statement Schedule	F-51

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management s assessment, included in the accompanying Managements Report on Internal Control over Financial Reporting, that Arch Coal, Inc. (the Company) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Arch Coal Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that Arch Coal, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion Arch Coal, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

Table of Contents

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Arch Coal, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006, of Arch Coal, Inc. and our report dated February 26, 2007, expressed an unqualified opinion thereon.

St. Louis, Missouri
February 26, 2007

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Arch Coal, Inc.

We have audited the accompanying consolidated balance sheets of Arch Coal, Inc. and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed in item 15. These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Arch Coal, Inc. and subsidiaries at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for share-based payments effective January 1, 2006. As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for stripping costs effective January 1, 2006. As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for pension and other postretirement benefits effective December 31, 2006.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Arch Coal, Inc. s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 26, 2007, expressed an unqualified opinion thereon.

St. Louis, Missouri
February 26, 2007

Table of Contents

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Arch Coal, Inc. (the Company) is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Securities Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company s management, including its principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria set forth in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, management concluded that the Company s internal control over financial reporting is effective as of December 31, 2006.

Management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2006 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included on page F-2.

Steven F. Leer	Robert J. Messey
Chairman and Chief	*Senior Vice President and Chief*
Executive Officer	*Financial Officer*

Table of Contents

REPORT OF MANAGEMENT

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

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

The Audit Committee of the Board of Directors, comprised of independent directors, meets regularly with management, the internal auditors, and the independent auditors to discuss matters relating to financial reporting, internal accounting control, and the nature, extent and results of the audit effort. The independent auditors and internal auditors have full and free access to the Audit Committee, with and without management present.

Steven F. Leer	Robert J. Messey
Chairman and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*

Table of Contents

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31		
	2006	2005	2004
	(In thousands, except per share data)		
REVENUES			
Coal sales	$ 2,500,431	$ 2,508,773	$ 1,907,168
COSTS, EXPENSES AND OTHER			
Cost of coal sales	1,909,822	2,174,007	1,638,646
Depreciation, depletion and amortization	208,354	212,301	166,322
Selling, general and administrative expenses	75,388	91,568	57,975
Other operating (income) expense:			
Gain on sale of units of Natural Resource Partners, LP			(91,268)
Gain on sale of Powder River Basin assets		(46,547)	
Gain on sale of Central Appalachian operations		(7,528)	
Other (income) expense, net	(29,800)	7,115	(42,553)
	2,163,764	2,430,916	1,729,122
Income from operations	336,667	77,857	178,046
Interest expense, net:			
Interest expense	(64,364)	(72,409)	(62,634)
Interest income	3,725	9,289	6,130
	(60,639)	(63,120)	(56,504)
Other non-operating income (expense):			
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	(4,836)	(7,740)	(9,010)
Other non-operating income (expense)	(2,611)	(3,524)	1,044
	(7,447)	(11,264)	(7,966)
Income before income taxes	268,581	3,473	113,576
Provision for (benefit from) income taxes	7,650	(34,650)	(130)
NET INCOME	260,931	38,123	113,706
Preferred stock dividends	(378)	(15,579)	(7,187)
Net income available to common stockholders	$ 260,553	$ 22,544	$ 106,519
EARNINGS PER COMMON SHARE			
Basic earnings per common share	$ 1.83	$ 0.18	$ 0.95
Diluted earnings per common share	$ 1.80	$ 0.17	$ 0.89

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

Table of Contents

CONSOLIDATED BALANCE SHEETS

	December 31	
	2006	2005
	(In thousands, except share and per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,523	$ 260,501
Trade accounts receivable	212,185	179,220
Other receivables	48,588	40,384
Inventories	129,826	130,720
Prepaid royalties	6,743	2,000
Deferred income taxes	51,802	88,461
Other	35,610	28,278
Total current assets	487,277	729,564
Property, plant and equipment:		
Coal lands and mineral rights	1,587,303	1,475,429
Plant and equipment	1,626,984	1,270,775
Deferred mine development	550,385	417,879
	3,764,672	3,164,083
Less accumulated depreciation, depletion and amortization	(1,521,604)	(1,334,457)
Property, plant and equipment, net	2,243,068	1,829,626
Other assets:		
Prepaid royalties	112,667	106,393
Goodwill	40,032	40,032
Deferred income taxes	263,759	223,856
Equity investments	80,213	8,498
Other	93,798	113,471
Total other assets	590,469	492,250
Total assets	$ 3,320,814	$ 3,051,440
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 198,875	$ 256,883
Accrued expenses	190,746	245,656
Current portion of debt	51,185	10,649
Total current liabilities	440,806	513,188
Long-term debt	1,122,595	971,755
Accrued postretirement benefits other than pension	49,817	41,326

Asset retirement obligations	205,530	166,728
Accrued workers compensation	43,655	53,803
Other noncurrent liabilities	92,817	120,399
Total liabilities	1,955,220	1,867,199
Stockholders equity:		
Preferred stock, $.01 par value, 10,000,000 shares authorized, issued and outstanding 143,771 and 150,508 shares, respectively, $50 liquidation preference	2	2
Common stock, $.01 par value, authorized 260,000,000 shares, issued 142,179,254 and 142,741,368 shares, respectively	1,426	719
Paid-in capital	1,345,188	1,367,470
Retained earnings (deficit)	38,147	(164,181)
Unearned compensation		(9,947)
Less treasury stock, at cost, 168,400 shares in 2005		(1,190)
Accumulated other comprehensive loss	(19,169)	(8,632)
Total stockholders equity	1,365,594	1,184,241
Total liabilities and stockholders equity	$ 3,320,814	$ 3,051,440

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

Table of Contents

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
Three Years Ended December 31, 2006

	Preferred Stock	Common Stock	Paid-In Capital	Retained Earnings (Deficit)	Unearned Compensation	Treasury Stock at Cost	Accumulated Other Comprehensive Loss	Total
	(In thousands, except share and per share data)							
BALANCE AT January 1, 2004	$ 29	$ 536	$ 988,476	$ (255,936)	$	$ (5,047)	$ (40,023)	$ 688,035
Comprehensive income:								
Net income				113,706				113,706
Minimum pension liability adjustment							1,221	1,221
Unrealized gains on available-for-sale securities							2,081	2,081
Net amount reclassified to income							8,524	8,524
Total comprehensive income								125,532
Dividends:								
Common ($0.1488 per share)				(16,856)				(16,856)
Preferred ($2.50 per share)				(7,187)				(7,187)
Issuance of 14,375,000 shares of common stock pursuant to public offering		72	230,455					230,527
Issuance of 1,000,000 shares of common stock as contribution to pension plan		5	15,435					15,440
Issuance of 298,380 shares of common stock under the stock incentive plan restricted stock units		1	4,246		(4,247)			
Employee stock-based					2,417			2,417

compensation expense								
Issuance of 3,316,358 shares of common stock under the stock incentive plan stock options, including income tax benefits		17	41,901					41,918
BALANCE AT DECEMBER 31, 2004	29	631	1,280,513	(166,273)	(1,830)	(5,047)	(28,197)	1,079,826
Comprehensive income:								
Net income				38,123				38,123
Minimum pension liability adjustment							(2,751)	(2,751)
Unrealized gains on available-for-sale securities							8,498	8,498
Unrealized gains on derivatives							22,646	22,646
Net amount reclassified to income							(8,828)	(8,828)
Total comprehensive income								57,688
Dividends:								
Common ($0.16 per share)				(20,452)				(20,452)
Preferred ($2.50 per share)				(6,053)				(6,053)
Preferred stock conversion	(27)	66	9,487	(9,526)				
Issuance of 546,000 shares of treasury stock as contribution to pension plan		3	12,872			3,857		16,732
Issuance of 3,037,722 shares of common stock under the stock incentive plan stock options, including income tax benefits		15	43,564					43,579
Employee stock-based			140		12,781			12,921

compensation expense								
Issuance of 680,092 shares of common stock under the stock incentive plans		4	20,894		(20,898)			
BALANCE AT DECEMBER 31, 2005	2	719	1,367,470	(164,181)	(9,947)	(1,190)	(8,632)	1,184,241
Comprehensive income:								
Net income				260,931				260,931
Minimum pension liability adjustment							14,941	14,941
Unrealized losses on available-for-sale securities							(8,834)	(8,834)
Unrealized losses on derivatives							(14,384)	(14,384)
Net amount reclassified to income							9,689	9,689
Total comprehensive income								262,343
Dividends:								
Common ($0.22 per share)				(31,448)				(31,448)
Preferred ($2.50 per share)				(378)				(378)
Contribution of 168,400 shares of treasury stock and 181,600 of common stock to pension plan		3	15,407			1,190		16,600
Issuance of 126,474 shares of common stock under the stock incentive plan restricted stock and restricted stock units								
Issuance of 31,320 shares of common stock upon conversion of preferred stock								

Effect of two for one stock split		716		(716)				
Issuance of 660,892 shares of common stock under the stock incentive plan stock options		4	7,039					7,043
Employee stock-based compensation expense			9,080					9,080
Purchase of 1,562,400 shares of common stock under stock repurchase program						(43,877)		(43,877)
Retirement of treasury stock		(16)	(43,861)			43,877		
Effect of adoption of EITF 04-6				(26,061)				(26,061)
Effect of adoption of Statement No. 158							(11,949)	(11,949)
Effect of adoption of Statement No. 123R			(9,947)		9,947			
BALANCE AT DECEMBER 31, 2006	$ 2	$ 1,426	$ 1,345,188	$ 38,147	$	$	$ (19,169)	$ 1,365,594

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

Table of Contents

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	2006	2005	2004
		(In thousands)	
OPERATING ACTIVITIES			
Net income	$ 260,931	$ 38,123	$ 113,706
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	208,354	212,301	166,322
Prepaid royalties expensed	9,045	14,252	13,889
Gain on sale of units of Natural Resource Partners, LP			(91,268)
Net (gain) loss on dispositions of property, plant and equipment	649	(82,168)	(6,668)
Gain on investment in Knight Hawk Holdings, LLC	(10,309)		
Employee stock-based compensation	9,080	12,937	
Net distributions from equity investments			17,678
Other non-operating expense	7,447	11,264	7,966
Changes in operating assets and liabilities (see Note 24)	(166,935)	28,377	(54,725)
Other	(10,160)	19,521	(18,172)
Cash provided by operating activities	308,102	254,607	148,728
INVESTING ACTIVITIES			
Capital expenditures	(623,187)	(357,142)	(292,605)
Payments for acquisitions, net of cash acquired			(387,751)
Proceeds from dispositions of property, plant and equipment	777	117,048	7,428
Proceeds from sale of units of Natural Resource Partners, LP			111,447
Additions to prepaid royalties	(20,062)	(28,164)	(33,813)
Advances to affiliates/purchases of investments	(45,533)	(23,285)	(2,000)
Cash used in investing activities	(688,005)	(291,543)	(597,294)
FINANCING ACTIVITIES			
Net borrowings (payments) on revolver and lines of credit	192,300	(25,000)	25,000
Net borrowings (payments) on long-term debt	442	(2,376)	(302)
Proceeds from issuance of senior notes			261,875
Debt financing costs	(2,171)	(2,662)	(12,806)
Dividends paid	(31,815)	(27,639)	(24,043)
Purchases of treasury stock	(43,876)		
Issuance of common stock under incentive plans and proceeds from sale of common stock	7,045	31,947	267,468
Cash provided by (used in) financing activities	121,925	(25,730)	517,192
Increase (decrease) in cash and cash equivalents	(257,978)	(62,666)	68,626
Cash and cash equivalents, beginning of year	260,501	323,167	254,541
Cash and cash equivalents, end of year	$ 2,523	$ 260,501	$ 323,167

SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year for interest	$ 59,116	$ 69,839	$ 53,558
Cash paid (received) during the year for income taxes	$ (8,921)	$ (5,518)	$ 13,350

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

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Accounting Policies

Basis of Presentation

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

On May 15, 2006, the Company completed a two-for-one stock split of the Company s common stock in the form of a 100% stock dividend. All share and per share amounts for the years ended December 31, 2005 and 2004 have been retroactively restated for the split.

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

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

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

Accounting Pronouncements Adopted

On December 31 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans* (Statement No. 158). Statement No. 158 requires that an employer recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) and other postemployment benefits determined on an actuarial basis as an asset or liability in its balance sheet and to recognize changes in the funded status though comprehensive income when they occur. Statement No. 158 also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet. See Notes 13 and 14 for additional disclosures relating to these obligations.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reflects the incremental effect of applying Statement No. 158 on individual line items in the accompanying Consolidated Balance Sheet at December 31, 2006:

	December 31, 2006 Balances Prior to Adoption of Statement No. 158	Adjustments	December 31, 2006 Balances After Adoption of Statement No. 158
		(In thousands)	
Other assets noncurrent	$ 15,427	$(15,427)	$
Deferred income taxes noncurrent	257,296	6,463	263,759
Total assets	3,329,778	(8,964)	3,320,814
Accrued benefit liability current	5,483	(973)	4,510
Accrued postretirement benefits other than pension noncurrent	42,567	7,250	49,817
Accrued benefit liability noncurrent	36,415	(20,742)	15,673
Total liabilities	1,952,235	2,985	1,955,220
Accumulated other comprehensive loss	(7,220)	(11,949)	(19,169)
Total stockholders equity	1,377,543	(11,949)	1,365,594

On January 1, 2006, the Company adopted the Emerging Issues Task Force Issue No. 04-6, *Accounting for Stripping Costs in the Mining Industry* (EITF 04-6). EITF 04-6 applies to stripping costs incurred in the production phase of a mine for the removal of overburden or waste materials for the purpose of obtaining access to coal that will be extracted. Under EITF 04-6, stripping costs incurred during the production phase of the mine are variable production costs that are included in the cost of inventory extracted during the period the stripping costs are incurred. Historically, the Company had classified stripping costs associated with the tons of coal uncovered and not yet extracted (pit inventory) at its surface mining operations as coal inventory. The effect of adopting EITF 04-6 was a reduction of $40.7 million and $2.0 million of inventory and deferred development costs, respectively, with a corresponding decrease to retained earnings, net of tax, of $26.1 million. This accounting change creates volatility in the Company s results of operations, as cost increases or decreases related to fluctuations in pit inventory can only be attributed to tons extracted from the pit. During the year ended December 31, 2006, decreases in pit inventory resulted in net income that was $10.6 million higher than it would have been under the Company s previous methodology of accounting for pit inventory, an impact of $0.07 per diluted share.

As of January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* (Statement No. 123R), which requires all public companies to measure compensation cost in the statement of income for all share-based payments (including employee stock options) at fair value. Prior to the adoption of Statement No. 123R, the Company accounted for its stock options under the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and related interpretations, as permitted by Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation*, as amended by Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* (Statement No. 123). The Company adopted Statement No. 123R using the modified-prospective method. Under this method, compensation cost for share-based payments to employees is based on their grant-date fair value from the beginning of the fiscal period in which the recognition provisions are first applied. Measurement and recognition of compensation cost for awards that were

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

granted prior to, but not vested as of, the date Statement No. 123R was adopted are based on the same estimate of the grant-date fair value and the same recognition method used previously under Statement No. 123. The Company uses the Black-Scholes option pricing model for its options and a lattice model for share-based payments with performance and market conditions to determine the fair value. Statement No. 123R also requires the benefits of tax deductions in excess of recognized compensation cost to be reported as a financing cash flow, rather than as an operating cash flow. The effects of adoption on retained earnings, net income and the statement of cash flows for the year ended December 31, 2006 were insignificant. See further discussion in Note 17, Stock Based Compensation and Other Incentive Plans.

Prior to the adoption of Statement No. 123R, the Company accounted for its stock options under the intrinsic value method prescribed by APB 25 and related interpretations as permitted by Statement No. 123. The following table reflects the pro forma disclosure of net income available to common stockholders and earnings per common share as required by Statement No. 123. Had compensation expense for stock option grants been determined based on the fair value at the grant dates for years ended December 31, 2005 and 2004, the Company s net income available to common stockholders and earnings per common share would have been as follows:

	Year Ended December 31	
	2005	**2004**
	(In thousands, except per share data)	
Net income available to common stockholders, as reported	$ 22,544	$ 106,519
Add:		
Stock-based employee compensation included in reported net income, net of related tax effects	12,768	1,837
Deduct:		
Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(16,894)	(7,302)
Pro forma net income available to common stockholders	$ 18,418	$ 101,054
Earnings per common share:		
Basic earnings per common share as reported	$ 0.18	$ 0.95
Basic earnings per common share pro forma	0.14	0.90
Diluted earnings per common share as reported	0.17	0.89
Diluted earnings per common share pro forma	0.14	0.85

Accounting Estimates

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

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash and Cash Equivalents

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

Allowance for Uncollectible Receivables

The Company maintains allowances to reflect the amounts of its trade accounts receivable and other receivables which are not expected to be collected, based on past collection history, the economic environment and specified risks identified in the receivables portfolio. Receivables are considered past due if the full payment is not received by the contractual due date. Allowances recorded at December 31, 2006 and 2005 were $3.2 million and $1.8 million, respectively.

Inventories

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs and operating overhead.

Investments

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

Prepaid Royalties

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

Coal Supply Agreements

Acquisition costs allocated to coal supply agreements (sales contracts) are capitalized and amortized on the basis of coal to be shipped over the term of the contract. Value is allocated to coal supply agreements based on discounted cash flows attributable to the difference between the above or below-market contract price and the then-prevailing market price. The net book value of the Company s above-market coal supply agreements was $3.8 million and $4.8 million at December 31, 2006 and 2005, respectively. These amounts are recorded in other assets in the accompanying Consolidated Balance Sheets. The net book value of all below-market coal supply agreements was $3.2 million and $15.0 million at December 31, 2006 and 2005, respectively. This amount is recorded in other noncurrent liabilities in the accompanying Consolidated Balance Sheets. Amortization expense on all above-market coal supply agreements was $1.0 million, $8.0 million and $3.8 million in 2006, 2005 and 2004, respectively.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amortization income on all below-market coal supply agreements was $11.8 million, $16.0 million and $4.1 million in 2006, 2005 and 2004, respectively.

Exploration Costs

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

Property, Plant and Equipment

Plant and Equipment

Plant and equipment are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. During the years ended December 31, 2006, 2005 and 2004, interest costs of $14.8 million, $4.2 million and $0.2 million were capitalized. Expenditures which extend the useful lives of existing plant and equipment or increase the productivity of the asset are capitalized. The cost of maintenance and repairs that do not extend the useful life or increase the productivity of the asset are expensed as incurred. Plant and equipment are depreciated principally on the straight-line method over the estimated useful lives of the assets, which generally range from three to 30 years, except for preparation plants and loadouts. Preparation plants and loadouts are depreciated using the units-of-production method over the estimated recoverable reserves, subject to a minimum level of depreciation.

Deferred Mine Development

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

Coal Lands and Mineral Rights

A significant portion of the Company s coal reserves are controlled through leasing arrangements. Amounts paid to acquire such reserves are capitalized and depleted over the life of those reserves that are proven and probable. Coal lease rights are depleted using the units-of-production method, and the rights are assumed to have no residual value. The leases are generally long-term in nature (original terms range from 10 to 50 years), and substantially all of the leases contain provisions that allow for automatic extension of the lease term as long as mining continues. The net book value of the Company s leased coal interests was $954.2 million and $908.7 million at December 31, 2006 and 2005, respectively.

The Company has entered into various non-cancelable royalty lease agreements and federal lease bonus payments under which future minimum payments are due. On September 22, 2004, the Company was the successful bidder in a federal auction of certain mining rights in the 5,084-acre Little Thunder tract in the Powder River Basin of Wyoming. The Company s lease bonus bid amounted to $611.0 million for the tract payable in five equal installments. The Company paid the first installment of $122.2 million in 2004 and the second in 2006, with the remaining three annual payments to be paid in fiscal years 2007 through 2009. These payments are capitalized as the cost of the underlying mineral reserves.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Impairment

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

Goodwill

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

Deferred Financing Costs

The Company capitalizes costs incurred in connection with borrowings or establishment of credit facilities and issuance of debt securities. These costs are amortized as an adjustment to interest expense over the life of the borrowing or term of the credit facility using the interest method. Deferred financing costs were $24.8 million and $27.4 million at December 31, 2006 and 2005, respectively. Amounts classified as current were $4.6 million and $5.1 million at December 31, 2006 and 2005, respectively.

Revenue Recognition

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

Other Operating (Income)/ Expense, net

Other operating (income) expense, net in the accompanying Consolidated Statements of Income reflects income and expense from sources other than coal sales, including royalties earned from properties leased to third parties and income from equity investments; gains and losses from dispositions of long-term assets; and unrealized gains and losses on derivatives that do not qualify for hedge accounting.

Asset Retirement Obligations

The Company s legal obligations associated with the retirement of long-lived assets are recognized at fair value at the time the obligations are incurred. Obligations are incurred at the time development of a mine commences for underground and surface mines or construction begins for support facilities, refuse areas and slurry ponds. The obligation s fair value is determined using discounted cash flow techniques and is accreted over time to its expected settlement value. Upon initial recognition of a liability, a

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

corresponding amount is capitalized as part of the carrying amount of the related long-lived asset. Amortization of the related asset is recorded on a units-of-production basis over the mine s estimated recoverable reserves. See additional discussion in Note 12, Asset Retirement Obligations.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage exposures to commodity prices and interest rates. Derivative financial instruments are recognized in the balance sheet at fair value. Changes in fair value are recognized in earnings if they are not eligible for hedge accounting or in other comprehensive income if they qualify for cash flow hedge accounting. Amounts in other comprehensive income are reclassified to earnings when the hedged transaction affects earnings. Any ineffective portion of a cash flow hedge s change in fair value is recognized immediately in earnings. The amount of ineffectiveness recognized in other (income) expense, net in the accompanying Consolidated Statements of Income for the years ended December 31, 2005 and 2004 was $1.0 million and $0.2 million, respectively. Ineffectiveness was insignificant for the year ended December 31, 2006.

The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives for undertaking various hedge transactions. The Company evaluates the effectiveness of its hedging relationships both at the hedge inception and on an ongoing basis.

Income Taxes

Deferred income taxes are provided for temporary differences arising from differences between the financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates expected to be in effect when the related taxes are expected to be paid or recovered.

Accounting Standards Issued and Not Yet Adopted

In February 2006, the FASB issued Statement of Financial Accounting Standards No. 155, *Accounting for Certain Hybrid Financial Instruments* (Statement No. 155). Statement No. 155 simplifies the accounting for certain hybrid financial instruments by permitting fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation. Statement No. 155 also clarifies and amends certain other provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* and Statement of Financial Accounting Standards No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities.* Statement No. 155 is effective for all financial instruments acquired, issued, or subject to a remeasurement event occurring after January 1, 2007. The Company does not expect the adoption of this statement to have a material impact on its financial statements.

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 prescribes a recognition threshold and measurement attributes for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006. While the Company expects there will be some impact of recognizing tax positions previously unrecognized under Statement of Financial

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounting Standards No. 5, *Accounting for Contingencies*, the Company is still analyzing FIN 48 to determine what the impact of adoption will be.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements* (Statement No. 157). Statement No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements and applies under other accounting pronouncements that require or permit fair value measurements. Statement No. 157 is effective prospectively for fiscal years beginning after November 15, 2007, and interim periods within that fiscal year. The Company is still analyzing Statement No. 157 to determine what the impact of adoption will be.

Reclassifications

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

2. Business Combinations

Canyon Fuel 35% Acquisition

On July 31, 2004, the Company purchased the 35% interest in Canyon Fuel that it did not own from ITOCHU Corporation. The purchase price, including related costs and fees, of $112.2 million was funded with cash of $90.2 million and a five-year, $22.0 million non-interest bearing note. Net of cash acquired, the fair value of the transaction totaled $97.4 million. As a result of the acquisition, the Company owns all of the ownership interests of Canyon Fuel and consolidates Canyon Fuel in its financial statements. The results of operations of the Canyon Fuel mines are included in the Company s Western Bituminous segment.

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Triton Acquisition

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

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

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

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

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

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pro Forma Financial Information

The following unaudited pro forma financial information for the year ended December 31, 2004 presents the combined results of operations of the Company, the remaining Canyon Fuel interest acquired from ITOCHU Corporation and the North Rochelle operations acquired from Triton on a pro forma basis, as though the purchases had occurred as of the beginning of the year. The pro forma financial information does not necessarily reflect the results of operations that would have occurred had the Company and the operations acquired from Canyon Fuel and Triton constituted a single entity during those periods (in thousands, except per share data):

Revenues:	
As reported	$ 1,907,168
Pro forma	2,156,958
Net income:	
As reported	113,706
Pro forma	103,933
Net income available to common stockholders:	
As reported	106,519
Pro forma	96,746
Basic earnings per common share:	
As reported	0.95
Pro forma	0.87
Diluted earnings per common share:	
As reported	0.89
Pro forma	0.82

3. Dispositions

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

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The net book value of the subsidiaries sold was a net liability of $123.1 million, consisting of the following (in thousands):

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

The Company recognized a $7.5 million net gain in the fourth quarter of 2005 in conjunction with this transaction. The gain recorded by the Company included accrued losses of $65.4 million on firm commitments to purchase coal in 2006 to supply below-market sales contracts, which could no longer be sourced from the Company s operations as a result of the transaction. As the Company shipped coal to satisfy the below-market contracts, the liability was relieved against cost of coal sales. In addition, the Company recognized expenses of $8.7 million during 2006 related to the finalization of working capital adjustments to the purchase price, adjustments to estimated volumes associated with sales contracts acquired by Magnum and expense related to settlement accounting for pension plan withdrawals. See further discussion of the settlement in Note 14, Employee Benefit Plans.

In accordance with the terms of the transaction, the Company paid $50.2 million to Magnum in 2006 to purchase coal and to offset certain ongoing operating expenses of Magnum. In addition, the Company was required under the agreement to manage working capital for the operations sold to Magnum for a period of time after the transaction. As of December 31, 2006, the Company had a current receivable due from Magnum of $8.5 million, included in other receivables on the accompanying Consolidated Balance Sheets.

In accordance with the Purchase Agreement, the Company agreed to various guarantees which are described in Note 22, Guarantees.

On December 30, 2005, the Company completed a reserve swap with Peabody Energy Corp. (Peabody) and sold to Peabody a rail spur, rail loadout and an idle office complex located in the Powder River Basin for a purchase price of $84.6 million. In the reserve swap, the Company exchanged 60.0 million tons of coal reserves for a similar block of 60.0 million tons of coal reserves with Peabody in order to facilitate more efficient mine plans for both companies. Due to the similarity of the exchanged reserves, the reserves received were recorded at the net book value of the reserves transferred. In conjunction with the transactions, the Company will continue to lease the rail spur and loadout and office facilities through

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2008 while it mines adjacent reserves. The Company recognized a gain of $46.5 million on the transaction, after the deferral of $7.0 million of the gain, equal to the present value of the lease payments. The deferred gain will be recognized over the term of the lease. See further discussion in Note 20, Leases.

During the years ended December 31, 2006, 2005 and 2004, gains (losses) on other dispositions of property, plant and equipment were $(0.6) million, $28.2 million and $6.7 million, respectively. Included in the gain for 2005 was a gain of $9.0 million on the sale of surface land rights at the Company s Central Appalachian operations in West Virginia, a gain of $6.3 million on the assignment of the Company s rights and obligations on several parcels of land and a gain of $7.3 million on the sale of a dragline. Included in the gain for 2004 was the sale of the Company s rights and obligations on a parcel of land to a third party resulting in a gain of $5.8 million.

4. Accumulated Other Comprehensive Income

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

	Financial Derivatives	Minimum Pension Liability Adjustments	Pension, Postretirement and Other Post-Employment Benefits	Available-for-Sale Securities	Accumulated Other Comprehensive Loss
			(In thousands)		
Balance January 1, 2004	$ (24,159)	$ (15,864)	$	$	$ (40,023)
2004 activity, before tax	13,974	2,002		3,411	19,387
2004 activity, tax effect	(5,450)	(781)		(1,330)	(7,561)
Balance December 31, 2004	(15,635)	(14,643)		2,081	(28,197)
2005 activity, before tax	22,652	(4,510)		13,931	32,073
2005 activity, tax effect	(8,834)	1,759		(5,433)	(12,508)
Balance December 31, 2005	(1,817)	(17,394)		10,579	(8,632)
2006 activity, before tax	(10,437)	24,914		(14,615)	(138)
2006 activity, tax effect	5,742	(9,973)		5,781	1,550
Statement No. 158 adoption		4,090	(22,502)		(18,412)
Statement No. 158 adoption, tax effect		(1,637)	8,100		6,463
Balance December 31, 2006	$ (6,512)	$	$ (14,402)	$ 1,745	$ (19,169)

As discussed in Note 1, Accounting Policies unrealized gains (losses) on derivatives that qualify for hedge accounting as cash flow hedges are recorded in other comprehensive income. The unrealized gains and losses on recording the Company s available-for-sale securities at fair value are recorded through other comprehensive income.

5. Investments

On July 31, 2006, the Company acquired a 33^{1}/3% equity interest in Knight Hawk Holdings, LLC (Knight Hawk), a coal producer in the Illinois Basin, in exchange for $15.0 million in cash and

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

approximately 30.0 million tons of coal reserves. The Company recognized a $10.3 million gain on the transaction, representing the difference between the fair market value of the reserves surrendered and their carrying value, less the amount of gain attributable to the ownership interest retained through the investment. This gain is reflected in other operating income, net on the accompanying Consolidated Statements of Income for the year ended December 31, 2006. The Company s income from its investment in Knight Hawk was $2.1 million for the year ended December 31, 2006. At December 31, 2006, the Company had an investment in Knight Hawk of $41.9 million.

On August 23, 2006, the Company acquired a 25% equity interest in DKRW Advanced Fuels LLC (DKRW), a company engaged in developing coal-to-liquids facilities. In exchange, the Company agreed to extend DKRW s existing coal reserve purchase option, to cooperate with DKRW to secure coal reserves at fair value for two additional coal-to-liquids projects outside of the Carbon Basin, and to invest $25.0 million in DKRW. The Company s portion of DKRW s loss was $0.1 million for the year ended December 31, 2006. At December 31, 2006 the Company had an investment in DKRW of $24.9 million.

The Company holds a 17.5% general partnership interest in Dominion Terminal Associates (DTA), which is accounted for on the equity method. DTA operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia used by the partners to transload coal. Financing for the facility was provided through $132.8 million of tax-exempt bonds issued by Peninsula Ports Authority of Virginia (PPAV). DTA leases the facility from PPAV for amounts sufficient to meet debt-service requirements. The Company retired its 17.5% share, or $23.2 million, of the bonds in the fourth quarter of 2005. Under the terms of a throughput and handling agreement with DTA, each partner is charged its share of cash operating and debt-service costs in exchange for the right to use the facility s loading capacity and is required to make periodic cash advances to DTA to fund such costs. The Company s portion of DTA s costs was $2.0 million, $3.4 million and $2.7 million for the years ended December 31, 2006, 2005 and 2004, respectively. At December 31, 2006 and 2005, the Company had an investment in DTA of $13.4 million and $8.5 million, respectively.

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

During the year ended December 31, 2004, the Company sold its remaining limited partnership units of Natural Resource Partners L.P. (NRP), representing approximately 12.5% of NRP s outstanding partnership interests, in three separate transactions occurring in March, June and October. These sales resulted in proceeds of approximately $111.4 million and gains of $91.3 million. The Company s income from the equity investment in NRP was $2.4 million for the year ended December 31, 2004.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 22, 2003, the Company sold 4.8 million subordinated units and its general partner interest in NRP for a purchase price of $115.0 million. This sale resulted in a gain of $70.6 million, of which $42.7 million was recognized in 2003 and the remainder was deferred. As of December 31, 2006 and 2005, the Company had deferred gains from its sales of NRP units totaling $5.5 million and $8.2 million, respectively. The deferred gains are included as other current liabilities and other noncurrent liabilities in the accompanying Consolidated Balance Sheets. Certain leases with NRP were related to the Company s operations sold as part of the Magnum transaction. The company recognized a gain of $5.8 million associated with these leases, which is included in the gain on the transaction with Magnum. The remaining deferred gains will be recognized over the remaining term of the Company s leases with NRP, as follows: $2.2 million in 2007, $1.1 million in 2008 and a total of $2.2 million from 2009 through 2012.

The fair value of investments in stock and other equity interests not accounted for under the equity method of accounting totaled $6.6 million and $23.8 million at December 31, 2006 and 2005, respectively.

6. Inventories

Inventories consist of the following:

	December 31	
	2006	2005
	(In thousands)	
Coal	$ 49,608	$ 73,284
Repair parts and supplies	80,218	57,436
	$ 129,826	$ 130,720

The repair parts and supplies are stated net of an allowance for slow-moving and obsolete inventories of $15.4 million and $16.1 million at December 31, 2006 and 2005, respectively.

The decrease in coal inventories is primarily the result of the implementation of EITF 04-6 discussed in Note 1, Accounting Policies as of January 1, 2006, partially offset by an increase in coal inventories primarily at the Western Bituminous segment s operations. The increase in repair parts and supplies is primarily the result of an increase in tire inventories and higher costs associated with materials and supplies.

7. Derivative Financial Instruments

Diesel fuel price risk management

The Company uses forward physical purchase contracts and heating oil swaps and purchased call options to reduce volatility in the price of diesel fuel for its operations. The changes in the price of heating oil highly correlate to changes in the price of diesel fuel. Accordingly, the derivatives qualify for hedge accounting and the changes in the fair value of the derivatives are recorded through other comprehensive income. At December 31, 2006, the Company held heating oil swaps and purchased call options protecting approximately 68% of its purchases for fiscal year 2007.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is a summary of our heating oil swaps and purchased call options:

	December 31, 2006		December 31, 2005	
	Quantity (Gallons)	Fair Value	Quantity (Gallons)	Fair Value
		(In thousands)		
Swaps current asset (liability)	17,100	$ (5,523)	22,800	$ 8,096
Purchased call options current asset	9,900	376	9,300	746

Sulfur dioxide emission allowance price risk management

The Company is exposed to price risk related to the value of sulfur dioxide emission allowances that are a component of the quality adjustment provisions in many of its coal supply agreements. The Company has historically purchased put options and entered into swap contracts to protect the Company from any downturn in the price of sulfur dioxide emission allowances. The Company may also purchase call options to mitigate the risk of changes in the fair value of a contract that contains a fixed price for sulfur dioxide emission allowances.

The following is a summary of sulfur dioxide emission allowance derivatives:

	December 31, 2006		December 31, 2005	
	Quantity	Fair Value	Quantity	Fair Value
		(In thousands)		
Swaps current liability		$	12,000	$ (11,949)
Purchased put options current asset	48,000	206	48,000	239
Purchased call options current asset	12,000	116		

For all of the outstanding put options at December 31, 2006, the Company elected hedge accounting treatment and the change in fair value was recorded through other comprehensive income. All other changes in fair value were recorded in other operating income, net in the accompanying Consolidated Statements of Income.

Interest rate risk management

In the fourth quarter of 2005, the Company terminated certain interest rate swap agreements that at one time had been designated as a hedge of interest rate volatility on floating rate debt. The amounts that had been deferred in accumulated other comprehensive income were amortized as additional expense over the contractual terms of the swap agreements prior to their termination. For the years ended December 31, 2005 and 2004, the Company recognized $(2.3) million and $0.9 million, respectively, of unrealized gains (losses) related to these swaps. In the fourth quarter of 2005, the Company terminated these swaps. For the years ended December 31, 2006, 2005 and 2004, the Company recognized $4.8 million, $7.7 million and $8.3 million of expense, respectively, related to the amortization of the balance in other comprehensive income. The remaining balance of $1.9 million will be amortized from accumulated other comprehensive income into net income in 2007.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Accrued Expenses

Accrued expenses included in current liabilities consist of the following:

	December 31	
	2006	2005
	(In thousands)	
Payroll and employee benefits	$ 50,741	$ 42,697
Taxes other than income taxes	73,235	59,828
Workers compensation	7,844	9,900
Interest	33,151	32,749
Asset retirement obligations	11,111	10,680
Losses on purchase commitments (see Note 3)		65,383
Due to Magnum (see Note 3)		16,000
Other accrued expenses	14,664	8,419
	$ 190,746	$ 245,656

9. Income Taxes

Significant components of the provision for (benefit from) income taxes are as follows:

	December 31		
	2006	2005	2004
	(In thousands)		
Current:			
Federal	$ 1,213	$ (13,703)	$ 7,583
State			
Total current	1,213	(13,703)	7,583
Deferred:			
Federal	22,700	(22,843)	(5,412)
State	(16,263)	1,896	(2,301)
Total deferred	6,437	(20,947)	(7,713)
	$ 7,650	$ (34,650)	$ (130)

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

December 31

	2006	2005	2004
		(In thousands)	
Income tax expense at statutory rate	$ 94,003	$ 1,216	$ 39,760
Percentage depletion allowance	(38,754)	(34,752)	(22,807)
State taxes, net of effect of federal taxes	1,576	(3,805)	1,729
Change in valuation allowance, affecting provision	(49,129)	(6,138)	(265)
Termination of interest rate swaps		5,049	180
Favorable tax settlement			(16,861)
Other, net	(46)	3,780	(1,866)
	$ 7,650	$ (34,650)	$ (130)

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2006, the tax effect of the adoption of EITF 04-6 was a $16.7 million benefit was recorded to retained earnings. Also, compensatory stock options and other equity based compensation awards were exercised resulting in a tax benefit of $7.7 million that will be allocated to paid-in capital at such point in time when a cash tax benefit is recognized.

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31	
	2006	2005
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 179,705	$ 187,122
Plant and equipment	103,906	88,213
Alternative minimum tax credit carryforwards	86,148	99,782
Losses on purchase commitments		60,499
Reclamation and mine closure	38,314	32,563
Workers compensation	20,245	21,704
Advance royalties	16,816	16,961
Postretirement benefits other than pension	15,689	12,942
Other comprehensive income	9,703	1,688
Tax-based intangibles	9,514	11,574
Other	55,120	43,289
Gross deferred tax assets	535,160	576,337
Valuation allowance	(114,034)	(163,163)
Total deferred tax assets	421,126	413,174
Deferred tax liabilities:		
Investment in tax partnerships	57,917	54,808
Deferred development	28,055	16,197
Coal inventory	1,138	15,842
Other	18,455	14,010
Total deferred tax liabilities	105,565	100,857
Net deferred tax asset	315,561	312,317
Less current asset	51,802	88,461
Long-term deferred tax asset	$ 263,759	$ 223,856

The Company has net operating loss carryforwards for regular income tax purposes that will expire from 2007 to 2023. The Company has an alternative minimum tax credit carryforward of $86.1 million, which has no expiration date and can be used to offset future regular tax in excess of the alternative minimum tax.

The Company has recorded a valuation allowance for a portion of its deferred tax assets that management believes, more likely than not, will not be realized. The valuation allowance decreased $49.1 million during 2006 and $6.1 million during 2005, due to a change in management s assessment of the ability of the Company to realize its deferred tax assets. Of the total valuation allowance at December 31, 2006, $6.5 million pertains to deferred tax benefits associated with the exercise of compensatory stock options and will be allocated to paid in capital when recognized.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Debt and Financing Arrangements

Debt consists of the following:

	December 31	
	2006	2005
	(In thousands)	
Indebtedness to banks under credit facilities, expiring in 2011	$ 192,300	$
6.75% senior notes ($950.0 million face value) due July 1, 2013	958,881	960,246
Promissory note due 2009	11,624	14,676
Other	10,975	7,482
	1,173,780	982,404
Less current portion	51,185	10,649
Long-term debt	$ 1,122,595	$ 971,755

On June 23, 2006, the Company entered into an amendment to its revolving credit facility to change the pricing grid upon which the interest rate under the credit facility is determined and to extend the maturity date from December 22, 2009 to June 23, 2011. As amended, borrowings under the credit facility bear interest at a floating rate based on LIBOR determined by reference to the Company s leverage ratio, as calculated in accordance with the credit agreement. In addition, the amendment to the credit facility increased the maximum amount of borrowings available to the Company from $700.0 million to $800.0 million and also revised certain restrictive negative covenants and other provisions. The Company s credit facility is secured by substantially all of its assets as well as its ownership interests in substantially all of its subsidiaries, except its ownership interests in Arch Western Resources, LLC and its subsidiaries. The rate in effect as of December 31, 2006 was 6.35%. As of December 31, 2006, borrowings of $103.1 million were outstanding under the credit facility. At December 31, 2006, the Company had $695.5 million of unused borrowings under the revolver. Financial covenant requirements may restrict the amount of unused capacity available to the Company for borrowings and letters of credit. As of December 31, 2006, the Company was not restricted by financial covenants.

On February 10, 2006, the Company established an accounts receivable securitization program, which was increased from $100.0 million to $150.0 million on June 23, 2006, and expires on February 3, 2011. Under the program, the Company s eligible trade receivables are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit. The entity through which these receivables are sold is consolidated into the Company s financial statements. The Company may borrow and draw letters of credit against the facility, and pays facility fees, program fees and letter of credit fees (based on amounts of outstanding letters of credit) at rates that are lower than its borrowings under the revolving credit facility. The fee structure was amended June 23, 2006 such that fees will be determined based on the Company s leverage ratio, as defined in the amendment. The rate in effect as of December 31, 2006 was 5.36%. As of December 31, 2006, borrowings of $89.2 million were outstanding under the program. At December 31, 2006, the Company had no available borrowing capacity under the program.

On October 22, 2004, Arch Western Finance LLC (Arch Western Finance), a subsidiary of the Company, issued $250.0 million of 6.75% Senior Notes due 2013 at a price of 104.75% of par. Interest on the notes is payable on January 1 and July 1 of each year. The senior notes were issued under an indenture

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

dated June 25, 2003, under which Arch Western Finance had previously issued $700.0 million of 6.75% Senior Notes due 2013. The senior notes are guaranteed by Arch Western Resources, LLC (Arch Western Resources), a subsidiary of Arch Western Finance, and certain of its subsidiaries and are secured by a security interest in loans made to Arch Coal by Arch Western Resources. The terms of the senior notes contain restrictive covenants that limit Arch Western Resources ability to, among other things, incur additional debt, sell or transfer assets, and make certain investments.

On July 31, 2004, the Company entered into a five-year, $22.0 million non-interest bearing note with ITOCHU Corporation to help fund the acquisition of the remainder of Canyon Fuel s membership interest. At its issuance, the note was discounted to its present value using a rate of 7.0%. The face amount of the promissory note of $13.0 million at December 31, 2006 is payable in quarterly installments of $1.0 million through July 2008 and $1.5 million from October 2008 through July 2009.

The Company also periodically establishes uncommitted lines of credit with banks. These agreements generally provide for short-term borrowings at market rates. At December 31, 2006, there were no such agreements in effect. At December 31, 2005, there were $20.0 million of such agreements in effect, under which no loans were outstanding.

Aggregate contractual maturities of debt are $51.2 million in 2007, $4.0 million in 2008, $4.3 million in 2009, $0 in 2010, $155.4 million in 2011 and $958.9 million thereafter.

Terms of the Company s credit facilities and leases contain financial and other covenants that limit the ability of the Company to, among other things, acquire or dispose of assets and borrow additional funds and that require the Company to, among other things, maintain various financial ratios and comply with various other financial covenants. In addition, the covenants require the pledging of assets to collateralize the Company s revolving credit facility. The assets pledged include equity interests in wholly-owned subsidiaries, certain real property interests, accounts receivable and inventory of the Company. Failure by the Company to comply with such covenants could result in an event of default, which, if not cured or waived, could have a material adverse effect on the Company. The Company complied with all financial covenants at December 31, 2006.

11. Fair Values of Financial Instruments

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

Cash and cash equivalents: At December 31, 2006 and 2005, the carrying amounts of cash and cash equivalents approximate fair value.

Debt: At December 31, 2006 and 2005, the fair value of the Company s senior notes and other long-term debt, including amounts classified as current, was $1,165.4 million and $1,001.6 million, respectively.

Derivatives. See Note 7, Derivative Financial Instruments for the fair value of the Company s derivative instruments.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Asset Retirement Obligations

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

The Company accounts for its reclamation obligations in accordance with Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.* The Company reviews its asset retirement obligation at least annually and makes necessary adjustments for permit changes as granted by state authorities and for revisions of estimates of the amount and timing of costs. For ongoing operations, adjustments to the liability result in an adjustment to the corresponding asset. For idle operations, adjustments to the liability are recognized as income or expense in the period the adjustment is recorded.

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

	2006	2005
	(In thousands)	
Balance at January 1 (including current portion)	$ 177,408	$ 199,597
Accretion expense	15,426	14,950
Reductions resulting from property disposals		(33,339)
Adjustments to the liability from changes in estimates	27,834	4,191
Liabilities settled	(4,027)	(7,991)
Balance at December 31	216,641	177,408
Current portion included in accrued expenses	(11,111)	(10,680)
Noncurrent liability	$ 205,530	$ 166,728

The adjustments from changes in estimates during the year ended December 31, 2006 resulted from changes in estimates of the timing of asset retirement costs and an increase in the cost estimates, primarily consumables such as tires.

As of December 31, 2006, the Company had $155.7 million in surety bonds outstanding and $265.2 million in self-bonding to secure reclamation obligations.

13. Accrued Workers Compensation

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

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Workers compensation expense consists of the following components:

	Year Ended December 31		
	2006	2005	2004
		(In thousands)	
Self-insured occupational disease benefits:			
Service cost	$ 1,014	$ 1,159	$ 1,447
Interest cost	959	1,852	2,660
Net amortization	(1,952)	(3,793)	(1,080)
Total occupational disease	21	(782)	3,027
Traumatic injury claims and assessments	8,552	20,196	18,725
Total provision	$ 8,573	$ 19,414	$ 21,752
Discount rate	5.90%	5.80%	6.00%
Cost escalation rate	3.00%	3.00%	4.00%

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

The reconciliation of changes in the benefit obligation of the occupational disease liability is as follows:

	December 31	
	2006	2005
	(In thousands)	
Beginning of year obligation	$ 16,907	$ 47,641
Service cost	1,014	1,159
Interest cost	959	1,852
Actuarial gain	560	(16,247)
Divestitures		(14,136)
Benefit and administrative payments	(405)	(3,362)
Net obligation at end of year	19,035	16,907
Unrecognized gain		9,763
Accrued cost	$ 19,035	$ 26,670

Summarized below is information about the amounts recognized in the accompanying Consolidated Balance Sheets for workers compensation benefits:

December 31

	2006	2005
	(In thousands)	
Occupational disease costs	$ 19,035	$ 26,670
Traumatic and other workers compensation claims	32,464	37,033
Total obligations	51,499	63,703
Less amount included in accrued expenses	7,844	9,900
Noncurrent obligations	$ 43,655	$ 53,803

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2006, the Company had $59.8 million in surety bonds and letters of credit outstanding to secure workers compensation obligations.

14. Employee Benefit Plans

Defined Benefit Pension and Other Postretirement Benefit Plans

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

A plan settlement occurred in the second quarter of 2006 because of plan withdrawals from the defined benefit pension plan primarily associated with the disposition of certain of the Company s subsidiaries to Magnum discussed in Note 3 Dispositions. The settlement resulted in an expense of $3.2 million, $1.9 million of which is reflected in other operating (income) expense and the remainder in cost of coal sales in the accompanying Consolidated Statements of Income. The settlement also triggered a remeasurement of the plan obligations as of June 30, 2006.

The Company also currently provides certain postretirement medical/life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement medical/life plans are contributory, with retiree contributions adjusted periodically, and contain other cost-sharing features such as deductibles and coinsurance. The Company s current funding policy is to fund the cost of all postretirement medical/life insurance benefits as they are paid.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
	(In thousands)			
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligations at January 1	$ 234,635	$ 218,063	$ 65,034	$ 535,870
Service cost	9,676	11,072	4,673	5,592
Interest cost	12,806	12,655	3,609	31,866
Plan amendments		242		20,010
Divestitures				(455,294)
Settlements	(28,887)			
Benefits paid	(4,471)	(16,228)	(1,432)	(32,963)
Other-primarily actuarial (gain) loss	7,475	8,831	(18,642)	(40,047)
Benefit obligations at December 31	$ 231,234	$ 234,635	$ 53,242	$ 65,034
CHANGE IN PLAN ASSETS				
Value of plan assets at January 1	$ 209,974	$ 191,109	$	$
Actual return on plan assets	20,124	15,060		
Settlements	(28,887)			
Employer contributions	19,321	20,034	1,432	32,963
Benefits paid	(4,471)	(16,228)	(1,432)	(32,963)
Value of plan assets at December 31	$ 216,061	$ 209,975	$	$
NET AMOUNT RECOGNIZED				
Funded status of the plans	$ (15,173)	$ (24,660)	$ (53,242)	$ (65,034)
Unrecognized actuarial loss		37,567		4,149
Unrecognized prior service cost (gain)		(330)		16,497
Prepaid (accrued) benefit cost	$ (15,173)	$ 12,577	$ (53,242)	$ (44,388)
ITEMS NOT YET RECOGNIZED AS A COMPONENT OF NET PERIODIC BENEFIT COST				
Prior service credit (cost)	$ 36	$	$ (14,950)	$
Accumulated gain (loss)	(29,959)		15,121	
	$ (29,923)	$	$ 171	$
BALANCE SHEET AMOUNTS				
Accrued benefit liabilities	$ (15,173)	$ (17,193)	$ (53,242)	$ (44,388)
Intangible asset (other assets)		766		
Minimum pension liability adjustment (accumulated other comprehensive income)		29,004		

Net asset (liability) recognized	$ (15,173)	$ 12,577	$ (53,242)	$ (44,388)
Current	$ (673)	$	$ (3,425)	$ (3,062)
Long-term	$ (14,500)	$ 12,577	$ (49,817)	$ (41,326)

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pension Benefits

The accumulated benefit obligation for all pension plans was $220.3 million and $227.0 million at December 31, 2006 and 2005, respectively.

The prior service credit and net loss that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2007 are $(0.3) million and $6.6 million, respectively.

Other Postretirement Benefits

The prior service cost and net gain that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2007 are $1.7 million and $(3.0) million, respectively.

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

The actuarial gain in 2005 resulted from changes in certain actuarial assumptions, including changes in the cost claims curve.

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

Year Ended December 31,	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
	(In thousands)					
Service cost	$ 9,676	$ 11,072	$ 8,861	$ 4,673	$ 5,592	$ 4,145
Interest cost	12,806	12,655	11,781	3,609	31,866	29,695
Expected return on plan assets*	(16,256)	(15,944)	(14,539)			
Other amortization and deferral	7,011	7,393	4,802	2,173	25,882	16,685
Settlements	3,150				59,195	
Net benefit cost	$ 16,387	$ 15,176	$ 10,905	$ 10,455	$ 122,535	$ 50,525

* The Company does not fund its other postretirement liabilities.

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

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
Weighted average assumptions:				
Discount rate	5.90%	5.80%	5.90%	5.80%
Rate of compensation increase	3.39%	3.50%	N/A	N/A

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
Weighted average assumptions:						
Discount rate	5.80%/6.40%	6.00%	6.50%	5.80%	6.00%	6.50%
Rate of compensation increase	3.50%	3.50%	3.75%	N/A	N/A	N/A
Expected return on plan assets	8.25%	8.50%	8.50%	N/A	N/A	N/A

Due to the plan settlement noted above, the Company remeasured the plan obligations as of June 30, 2006 and changed the discount rate to 6.40% for the second half of 2006. The Company establishes the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The Company utilizes modern portfolio theory modeling techniques in the development of its return assumptions. This technique projects rates of returns that can be generated through various asset allocations that lie within the risk tolerance set forth by members of the Company s pension committee (the Pension Committee). The risk assessment provides a link between a pension s risk capacity, management s willingness to accept investment risk and the asset allocation process, which ultimately leads to the return generated by the invested assets. For the determination of net periodic benefit cost in 2007, the Company will utilize an expected rate of return of 8.5%.

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

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

	December 31	
	2006	2005
Equity securities	72%	71%
Debt securities	23%	23%
Cash and equivalents	5%	6%
Total	100%	100%

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

Cash Flows. The Company expects to make contributions of $1.7 million to its pension plans in 2007.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2007	$ 14,112	$ 3,425
2008	15,344	3,609
2009	16,612	3,815
2010	17,791	4,067
2011	18,627	4,386
Years 2012-2016	105,432	25,146
	$187,918	$44,448

Multi-employer Pension and Benefit Plans

The Coal Industry Retiree Health Benefit Act of 1992 (Benefit Act) provides for the funding of medical and death benefits for certain retired members of the UMWA through premiums to be paid by assigned operators (former employers), transfers in 1993 and 1994 from an overfunded pension trust established for the benefit of retired UMWA members, and transfers from the Abandoned Mine Lands Fund (funded by a federal tax on coal production) commencing in 1995. The Company treats its obligation under the Benefit Act as a participation in a multi-employer plan and records expense as premiums are paid. The Company recorded expense of $1.1 million, $3.4 million and $6.0 million in the years ended December 31, 2006, 2005 and 2004, respectively, for premiums pursuant to the Benefit Act.

Other Plans

The Company sponsors savings plans which were established to assist eligible employees in providing for their future retirement needs. The Company s expense representing its contributions to the plans was $13.4 million, $12.4 million and $8.8 million for the years ended December 31, 2006, 2005 and 2004, respectively.

15. Capital Stock

On March 14, 2006, the Company filed a registration statement on Form S-3 with the SEC. The registration statement allows the Company to offer, from time to time, an unlimited amount of debt securities, preferred stock, depositary shares, purchase contracts, purchase units, common stock and related rights and warrants.

Common Stock

On May 15, 2006, the Company completed a two-for-one stock split of the Company s common stock in the form of a 100% stock dividend. All share and per share amounts for the years ended December 31, 2005 and 2004, have been retroactively restated for the split.

On October 28, 2004, the Company completed a public offering of 14,375,000 common shares at $16.93 per share. The proceeds from the offering, net of the underwriters discount and related expenses,

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

were $230.5 million. Net proceeds from the offering were used primarily to repay borrowings under the Company s revolving credit facility incurred to finance the acquisition of Triton and the first annual payment under the Little Thunder lease, and the remaining net proceeds were used for general corporate purposes, including the development of the Mountain Laurel mine complex in the Central Appalachia region.

Preferred Stock

Dividends on the Company s 5% Perpetual Cumulative Convertible Preferred Stock (Preferred Stock) are cumulative and payable quarterly at the annual rate of 5% of the liquidation preference. Each share of the Preferred Stock is convertible, under certain conditions, into 4.797 shares of the Company s common stock. The Preferred Stock is redeemable, at the Company s option, on or after January 31, 2008 if certain conditions are met. The holders of the Preferred Stock are not entitled to voting rights on matters submitted to the Company s common stockholders. However, if the Company fails to pay the equivalent of six quarterly dividends, the holders of the Preferred Stock will be entitled to elect two directors to the Company s Board of Directors. During 2006, 6,737 shares of preferred stock were converted to common stock.

On December 1, 2005, the Company issued a tender offer to induce conversion of its Preferred Stock (the Conversion Offer). The Conversion Offer expired on December 30, 2005. The Company accepted for conversion 2,724,418 shares of Preferred Stock to be converted to 13,308,238 shares of common stock, including a conversion premium of 0.0220 shares, on December 31, 2005. The Company recognized a dividend on the Preferred Stock in the amount of $9.5 million, representing the difference in the fair market value of the shares issued in conversion and those convertible pursuant to the original conversion terms.

Stock Repurchase Plan

In September 2006, the Company s Board of Directors authorized a share repurchase program, replacing a program that had been adopted in 2001, for the purchase of up to 14,000,000 shares of the Company s common stock. At December 31, 2006, 12,437,600 million shares of common stock were available for repurchase under the plan. During 2006, the Company purchased 1,562,400 shares of common stock for $43.9 million at an average cost of $28.08 per share. The repurchased shares were retired on December 18, 2006. Future repurchases under the plan will be made at management s discretion and will depend on market conditions and other factors. During 2006 and 2005, 168,400 and 546,000 treasury shares, respectively that were purchased under the former plan were contributed to the pension plans.

16. Stockholder Rights Plan

Under a stockholder rights plan, preferred share purchase rights (Preferred Purchase Rights) entitle their holders to purchase two hundredths of a share of a series of junior participating preferred stock at an exercise price of $42. The Preferred Purchase Rights are exercisable only when a person or group (an Acquiring Person) acquires 20% or more of the Company s common stock or if a tender or exchange offer is announced which would result in ownership by a person or group of 20% or more of the Company s common stock. In certain circumstances, the Preferred Purchase Rights allow the holder (except for the Acquiring Person) to purchase the Company s common stock or voting stock of the

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Acquiring Person at a discount. The Board of Directors has the option to allow some or all holders (except for the Acquiring Person) to exchange their rights for Company common stock. The rights will expire on March 20, 2010, subject to earlier redemption or exchange by the Company as described in the plan.

17. Stock Based Compensation and Other Incentive Plans

The Company s Stock Incentive Plan (the Incentive Plan) reserved 18,000,000 shares of the Company s common stock for awards to officers and other selected key management employees of the Company. The Incentive Plan provides the Board of Directors with the flexibility to grant stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance stock or units, merit awards, phantom stock awards and rights to acquire stock through purchase under a stock purchase program (Awards). Awards the Board of Directors elects to pay out in cash do not count against the 18,000,000 shares authorized in the Incentive Plan. The Incentive Plan calls for the adjustment of shares awarded under the plan in the event of a split.

As of December 31, 2006, the Company had stock options, restricted stock, restricted stock units and price contingent stock awards outstanding under the Incentive Plan.

Stock Options

Stock options are generally subject to vesting provisions of at least one year from the date of grant and are granted at a price equal to 100% of the closing market price of the Company s common stock on the date of grant. Information regarding stock option activity under the Incentive Plan follows for the year ended December 31, 2006:

	Common Shares (In thousands)	Weighted Average Exercise Price	Aggregate Intrinsic Value (In thousands)	Average Contract Life
Options outstanding at January 1	2,916	$ 10.40		
Granted	27	33.75		
Exercised	(661)	10.64		
Canceled	(9)	18.07		
Options outstanding at December 31	2,273	10.58	$ 44,152	4.67
Options exercisable at December 31	2,203	10.18	43,732	4.56

The aggregate intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004, was $21.2 million, $46.1 million, and $18.3 million, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Information regarding changes in stock options outstanding and not yet vested and the related grant-date fair value under the Incentive Plan follows for the year ended December 31, 2006:

	Common Shares	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested options at January 1	974	$ 4.47
Granted	27	13.53
Vested	(922)	4.28
Canceled	(9)	8.14
Unvested options at December 31	70	9.94

Compensation cost of stock option grants is recognized straight-line over the options vesting periods. Compensation expense related to stock options for the year ended December 31, 2006 was $1.5 million. As of December 31, 2006, there was $0.7 million of unrecognized compensation cost related to the unvested stock options. The total fair value of options vested during the years ended December 31, 2006, 2005 and 2004, was $4.0 million, $5.9 million and $20.2 million, respectively. The options fair value was determined using the Black-Scholes option pricing model. Expected volatilities are based on historical stock price movement, and other factors. Substantially all stock options granted vest ratably over three years. The majority of the cost relating to the stock-based compensation plans is included in selling, general and administrative expenses in the accompanying Consolidated Statements of Income.

	2006	2005	2004
Weighted average fair value per share of options granted	$ 13.53	$ 8.45	$ 7.69
Assumptions (weighted average):			
Risk-free interest rate	4.75%	3.70%	3.65%
Expected dividend yield	0.7%	0.9%	1.0%
Expected volatility	40.7%	51.1%	52.7%
Expected life (in years)	5.0	5.0	5.0

Restricted Stock and Restricted Stock Unit Awards

The Company may issue restricted stock and restricted stock units, which require no payment from the employee. Restricted stock cliff-vests at various dates and restricted stock units typically vest ratably over three years. Compensation expense is based on the fair value on the grant date and is recorded ratably over the vesting period. During the vesting period, the employee receives cash compensation equal to the amount of dividends that would have been paid on the underlying shares.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Information regarding restricted stock and restricted stock unit activity and weighted average grant-date fair value follows for the year ended December 31, 2006:

	Restricted Stock		Restricted Stock Units	
	Common Shares	Weighted Average Grant-Date Fair Value	Common Shares	Weighted Average Grant-Date Fair Value
	(In thousands)		(In thousands)	
Outstanding at January 1	82	$23.20	327	$14.49
Granted	18	36.73	32	37.77
Vested	(14)	21.75	(109)	15.47
Canceled				
Outstanding at December 31	86	26.20	250	16.98

The weighted average fair value of restricted stock granted during 2005 was $23.01. The weighted average fair value of restricted stock units granted during 2005 and 2004 was $22.27 and $14.23, respectively. The total fair value of restricted stock that vested during 2006 was $0.3 million. The total fair value of restricted stock units that vested during 2006 and 2005 was $1.7 million and $1.4 million, respectively. Unearned compensation of $2.7 million will be recognized over the remaining vesting period of the outstanding restricted stock and restricted stock units. The Company recognized expense of approximately $2.0 million, $2.2 million and $2.4 million related to restricted stock and restricted stock units for the years ended December 31, 2006, 2005 and 2004, respectively.

Performance-Contingent Phantom Stock Awards

The Company awarded performance-contingent phantom stock to 11 of its executives in the third quarter of 2005. The awards allow participants to earn up to an aggregate of 505,200 units, to be paid out in both cash and stock upon attainment of certain levels of stock price and EBITDA, as defined by the Company. Under Statement No. 123R, the cash portion of the plan is accounted for as a liability, based on the estimated payout under the awards. The stock portion is recorded utilizing the grant-date fair value of the award, based on a lattice model valuation. The Company met the EBITDA target in the third quarter of 2006 and estimates meeting the stock price target in 2007 and issuing the maximum 505,200 units under the plan. The Company recognized $7.9 million and $4.5 million of expense related to this award in the years ended December 31, 2006 and 2005, respectively. The expense is included in selling, general and administrative expenses in the accompanying Consolidated Statements of Income.

On January 14, 2004, the Company granted an award of 441,532 shares of performance-contingent phantom stock that vested in the event the Company s stock price reached an average pre-established price over a period of 20 consecutive trading days within five years following the date of grant. On March 3, 2005, the price contingency discussed above was met, and the award was paid in a combination of Company stock ($7.3 million) and cash ($2.6 million). As such, the Company recognized a $9.9 million charge as a component of selling, general and administrative expense ($9.1 million) and cost of coal sales ($0.8 million) in the accompanying Consolidated Statements of Income.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. Risk Concentrations

Credit Risk and Major Customers

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

The Company markets its coal principally to electric utilities in the United States. Sales to customers in foreign countries were $162.5 million, $166.0 million and $134.0 million for the years ended December 31, 2006, 2005 and 2004, respectively. As of December 31, 2006 and 2005, accounts receivable from electric utilities located in the United States totaled $159.7 million and $146.6 million, respectively, or 76% and 82% of total trade receivables for 2006 and 2005, respectively. Generally, credit is extended based on an evaluation of the customer s financial condition, and collateral is not generally required. Credit losses are provided for in the financial statements and historically have been minimal.

The Company is committed under long-term contracts to supply coal that meets certain quality requirements at specified prices. These prices are generally adjusted based on indices. Quantities sold under some of these contracts may vary from year to year within certain limits at the option of the customer. The Company and its operating subsidiaries sold approximately 135.0 million tons of coal in 2006. Approximately 78% of this tonnage (representing 77% of the Company s revenue) was sold under long-term contracts (contracts having a term of greater than one year). Prices for coal sold under long-term contracts ranged from $6.70 to $101.09 per ton. Long-term contracts ranged in remaining life from one to 11 years. Some of these contracts include pricing which is above current market prices. Sales (including spot sales) to major customers were as follows:

	2006	2005	2004
		(In thousands)	
TVA	$ 317,837	$ 306,896	$ 147,338
Progress Energy	69,143	199,514	228,203

Transportation

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

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. Earnings per Common Share

The following table sets forth the computation of basic and diluted earnings per common share. All share and per share amounts for the years ended December 31, 2005 and 2004 have been retroactively restated for the two-for-one split discussed in Note 1, Accounting Policies.

	2006		
	Numerator (Income)	Denominator (Shares)	Per Share Amount
	(In thousands, except per share data)		
Basic EPS:			
Net income	$ 260,931	142,770	$ 1.83
Preferred stock dividends	(378)		
Basic income available to common stockholders	$ 260,553		$ 1.83
Effect of dilutive securities:			
Effect of common stock equivalents under Incentive Plan		1,342	
Effect of common stock equivalents arising from Preferred Stock	378	700	
Diluted EPS:			
Diluted income available to common stockholders	$ 260,931	144,812	$ 1.80

	2005		
	Numerator (Income)	Denominator (Shares)	Per Share Amount
	(In thousands, except per share data)		
Basic EPS:			
Net income	$ 38,123	127,304	$ 0.30
Preferred stock dividends	(15,579)		(0.12)
Basic income available to common stockholders	$ 22,544		$ 0.18
Effect of dilutive securities:			
Effect of common stock equivalents under Incentive Plan		1,914	
Effect of common stock equivalents arising from Preferred Stock	18	722	
Diluted EPS:			
Diluted income available to common stockholders	$ 22,562	129,940	$ 0.17

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2004		
	Numerator (Income)	Denominator (Shares)	Per Share Amount
	(In thousands, except per share data)		
Basic EPS:			
Net income	$ 113,706	111,802	$ 1.02
Preferred stock dividends	(7,187)		(0.07)
Basic income available to common stockholders	$ 106,519		$ 0.95
Effect of dilutive securities:			
Effect of common stock equivalents under Incentive Plan		1,874	
Effect of common stock equivalents arising from Preferred Stock	7,187	13,792	
Diluted EPS:			
Diluted income available to common stockholders	$ 113,706	127,468	$ 0.89

For the year ended December 31, 2005, 13,070,000 shares, representing the common stock conversion equivalent of the Preferred Stock converted on December 31, 2005, and $15.6 million, representing the related dividends and conversion inducement, were excluded from the diluted earnings per common share calculation because their effect was anti-dilutive.

20. Leases

The Company leases equipment, land and various other properties under non-cancelable long-term leases, expiring at various dates. Certain leases contain options that would allow the Company to extend the lease or purchase the leased asset at the end of the base lease term. Rental expense related to these operating leases amounted to $28.8 million in 2006, $31.8 million in 2005 and $22.7 million in 2004. In addition, the Company enters into various non-cancelable royalty lease agreements under which future minimum payments are due.

Minimum payments due in future years under these agreements in effect at December 31, 2006 are as follows:

	Operating Leases	Royalties
	(In thousands)	
2007	$ 28,042	$ 26,878
2008	27,173	25,191
2009	22,842	23,038
2010	19,435	22,442
2011	22,385	20,619
Thereafter	19,947	21,861
	$ 139,824	$ 140,029

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

present value of the minimum lease payments, to be amortized over the term of the lease. At December 31, 2006 and 2005, the Company had deferred gains totaling $4.5 million and $7.0 million, respectively, related to the sale.

As of December 31, 2006, certain of the Company s lease obligations were secured by outstanding surety bonds totaling $33.0 million.

21. Related Party Transactions

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

From October 2002 through October 2004, the Company held an ownership interest in NRP. The Company leases certain coal reserves from NRP and pays royalties to NRP for the right to mine those reserves. Terms of the leases require the Company to prepay royalties with those payments recoupable against production. Amounts recognized as cost of coal sales for royalties paid to NRP during the year ended December 31, 2004 was $15.4 million.

22. Guarantees

In accordance with the Purchase Agreement, the Company agreed to continue to provide surety bonds and letters of credit for reclamation, workers compensation and retiree healthcare obligations of Magnum related to the properties sold on December 31, 2005 in order to facilitate an orderly transition. The Purchase Agreement requires Magnum to reimburse the Company for costs related to the surety bonds and letters of credit and to use commercially reasonable efforts after closing to replace the obligations. If the surety bonds and letters of credit related to the reclamation obligations are not replaced by Magnum within two years of closing the transaction, Magnum must post a letter of credit in favor of the Company in the amounts of the obligations. Letters of credit related to workers compensation obligations were replaced by Magnum during the fourth quarter of 2006. At December 31, 2006, the Company has $92.0 million of surety bonds related to properties sold to Magnum.

In addition, the Company has agreed to guarantee the performance of Magnum with respect to certain coal sales contracts sold to Magnum, the longest of which extends to the year 2017, and certain operating leases, the longest of which ends in 2011. Under the coal sales contracts, the customers must approve the assignment of the contracts to Magnum. Until the contracts are assigned, the Company is purchasing the coal from Magnum to sell to these customers at the same price it is charging the customers for the sale. One customer agreed to the assignment in the second quarter of 2006, under the agreement that the Company would continue to guarantee Magnum s performance until the end of 2006. If Magnum is unable to supply the coal for these coal sales contracts then the Company would be required to purchase coal on the open market or supply the contract from its existing operations. If the Company were required to

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

purchase coal to supply the contracts over their duration at market prices effective at December 31, 2006, the cost of the purchased coal would exceed the sales price under the contracts by $97.1 million. If the Company were required to perform under its guarantee of the operating lease agreements, it would be required to make $15.3 million of lease payments. The Company believes that it is remote that the Company would be required to perform under these guarantees. However, if the Company would have to perform under these guarantees, it could potentially have a material adverse effect on the business, results of operations and financial condition of the Company.

In connection with the Company s acquisition of the coal operations of Atlantic Richfield Company (ARCO) and the simultaneous combination of the acquired ARCO operations and the Company s Wyoming operations into the Arch Western joint venture, the Company agreed to indemnify the other member of Arch Western against certain tax liabilities in the event that such liabilities arise prior to June 1, 2013 as a result of certain actions taken, including the sale or other disposition of certain properties of Arch Western, the repurchase of certain equity interests in Arch Western by Arch Western or the reduction under certain circumstances of indebtedness incurred by Arch Western in connection with the acquisition. If the Company were to become liable, the maximum amount of potential future tax payments was $173.7 million at December 31, 2006, of which none is recorded as a liability on the Company s financial statements. Since the indemnification is dependent upon the initiation of activities within the Company s control and the Company does not intend to initiate such activities, it is remote that the Company will become liable for any obligation related to this indemnification. However, if such indemnification obligation were to arise, it could potentially have a material adverse effect on the business, results of operations and financial condition of the Company.

In addition, tax reporting applied to this transaction by the other member of Arch Western was being audited by the Internal Revenue Service (IRS). The Company does not believe that it is bound by the outcome of this audit. Nevertheless, the Company anticipates that it will soon begin negotiations with the IRS as to adjustments, if any, of Arch Western s tax reporting. The outcome of these negotiations when settled could result in adjustments to the basis of the partnership assets, and it is possible the Company may be required to adjust its deferred income taxes associated with its investment in Arch Western. Given the uncertainty of how an adverse outcome would affect the Company s deferred income tax position coupled with potential offsetting tax positions that the Company may be able to take, the Company is not able to reasonably determine the resulting outcome of this issue. However, any change that impacts the Company related to an IRS negotiation may result in a non-cash decrease in deferred income tax assets associated with the Company s investment in Arch Western and could fall within a range of zero to $41.0 million.

23. Contingencies

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

24. Cash Flow

The changes in operating assets and liabilities as shown in the accompanying Consolidated Statements of Cash Flows are comprised of the following:

	Year Ended December 31		
	2006	2005	2004
	(In thousands)		
Increase in operating assets:			
Receivables	$ (49,265)	$ (48,432)	$ (31,570)
Inventories	(39,783)	(38,368)	(12,422)
Increase (decrease) in operating liabilities:			
Accounts payable and accrued expenses	(115,123)	108,536	(6,780)
Income taxes	20,505	(33,513)	(4,215)
Accrued postretirement benefits other than pension	8,662	28,660	18,019
Asset retirement obligations	10,967	6,498	5,126
Accrued workers compensation	(2,898)	(9,705)	(1,257)
Other		14,701	(21,626)
Changes in operating assets and liabilities	$ (166,935)	$ 28,377	$ (54,725)

25. Segment Information

The Company produces steam and metallurgical coal from surface and underground mines for sale to utility, industrial and export markets. The Company operates only in the United States, with mines in the major low-sulfur coal basins. The Company has three reportable business segments, which are based on the coal basins in which the Company operates. Geology, coal transportation routes to customers, regulatory environments and coal quality are generally consistent within a basin. Accordingly, market and contract pricing have developed by coal basin. The Company manages its coal sales by coal basin, not by individual mine complex. Mine operations are evaluated based on their per-ton operating costs (defined as including all mining costs but excluding pass-through transportation expenses), as well as on other non-financial measures, such as safety and environmental performance. The Company s reportable segments are Powder River Basin (PRB), with operations in Wyoming; Central Appalachia (CAPP), with operations in southern West Virginia, eastern Kentucky and Virginia; and Western Bituminous (WBIT), with operations in Utah and Colorado and Southern Wyoming.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Operating segment results for the years ended December 31, 2006, 2005 and 2004 are presented below. Results for the operating segments include all direct costs of mining. Corporate, Other and Eliminations includes corporate overhead, land management, other support functions, and the elimination of intercompany transactions.

	PRB	CAPP	WBIT	Corporate, Other and Eliminations	Consolidated
			(In thousands)		
December 31, 2006					
Coal sales	$ 1,043,373	$ 998,112	$ 458,946	$	$ 2,500,431
Income (loss) from operations	215,696	58,835	126,387	(64,251)	336,667
Total assets	1,584,483	857,934	1,841,104	(962,707)	3,320,814
Depreciation, depletion and amortization	111,350	48,789	46,530	1,685	208,354
Capital expenditures	121,736	231,311	138,631	131,509	623,187

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

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

A reconciliation of segment income from operations to consolidated income before income taxes follows:

	2006	2005	2004
		(In thousands)	
Income from operations	$ 336,667	$ 77,857	$ 178,046
Interest expense	(64,364)	(72,409)	(62,634)
Interest income	3,725	9,289	6,130
Other non-operating expense	(7,447)	(11,264)	(7,966)
Income before income taxes	$ 268,581	$ 3,473	$ 113,576

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

26. Quarterly Financial Information (Unaudited)

Quarterly financial data for the years ended December 31, 2006 and 2005 is summarized below:

	March 31 (a)(b)(c)	June 30 (a)(b)(c)	September 30 (a)(b)(c)(d)	December 31 (a)(b)(c)
		(In thousands)		
2006:				
Coal sales	$ 634,553	$ 637,476	$ 610,045	$ 618,357
Gross profit	105,782	113,867	81,946	80,660
Income from operations	94,137	99,848	82,201	60,481
Net income available to common stockholders	60,624	69,593	50,825	79,511
Basic earnings per common share(g)	0.43	0.49	0.35	0.56
Diluted earnings per common share(g)	0.42	0.48	0.35	0.55

	March 31 (e)(f)	June 30	September 30 (e)	December 31 (a)(b)(e)(f)
		(In thousands)		
2005:				
Coal sales	$ 600,464	$ 633,797	$ 654,716	$ 619,796
Gross profit	29,921	39,582	50,149	2,813
Income (loss) from operations	25,952	21,493	34,177	(3,765)
Net income (loss) available to common stockholders	4,778	1,677	17,129	(1,040)
Basic earnings (loss) per common share(g)	0.04	0.01	0.13	(0.01)
Diluted earnings (loss) per common share(g)	0.04	0.01	0.13	(0.01)

(a) A combustion-related event in October 2005 caused the idling of the Company s West Elk mine in Colorado into the first quarter of 2006, which cost the Company an estimated $30.0 million in lost profits during the first quarter of 2006, in addition to the effect of the idling and fire-fighting costs incurred during the fourth quarter of 2005 of $33.3 million. The Company recorded insurance recoveries related to the event in the first, second, third and fourth quarters of 2006 of $10.0 million, $10.0 million, $10.0 million and $11.9 million, respectively. Of these recoveries, $19.5 million was for business interruption. The insurance recoveries are reflected as a reduction of cost of coal sales in the accompanying Consolidated Statements of Income and the balance receivable at December 31, 2006 of $11.9 million related to these recoveries is reflected in other current receivables on the accompanying Consolidated Balance Sheets.

(b) On December 31, 2005, the Company sold the stock of three subsidiaries and their four associated mining operations and coal reserves in Central Appalachia to Magnum. During the first, second, third and fourth quarters of 2006, the Company recorded a charge to earnings of $6.7 million, $1.7 million, $0.1 million and $0.2 million, respectively, related primarily to the finalization of working capital adjustments to the purchase price, pursuant to the Purchase Agreement, adjustments to estimated volumes associated with sales contracts acquired by Magnum and the settlement of pension obligations. During the fourth quarter of 2005 the Company recognized a gain on the sale of its Central Appalachian operations to Magnum of $7.5 million.

(c) On January 1, 2006, the Company adopted EITF 04-6. Under EITF 04-6, stripping costs incurred during the production phase of the mine are variable production costs that are included in the cost of inventory extracted during the period the stripping costs are incurred. Historically, the Company had classified stripping costs at its surface mining operations associated with the tons of coal uncovered and not yet extracted (pit inventory) as coal inventory. During the first, second, third and fourth quarters of 2006, the Company s net income was $5.1 million, $2.7 million, $3.8 million and $(1.0) million higher

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(lower) than it would have been under the Company s previous method of accounting for pit inventory, an impact of $0.04, $0.02, $0.03 and $(0.01) per share respectively.

(d) During the third quarter of 2006, the Company acquired a 33 1/3% equity interest in Knight Hawk in exchange for $15.0 million in cash and approximately 30.0 million tons of coal reserves. The Company recognized a $10.3 million gain reflected in other operating income, net on the transaction, representing the difference between the fair market value of the reserves surrendered and their carrying value, less the amount of gain attributable to the ownership interest retained through the investment.

(e) The Company recognized a gain of $6.3 million on the assignment of its rights and obligations on several parcels of land in West Virginia and a gain of $7.3 million on a dragline sale in the first quarter of 2005, and a gain of $9.0 million on the sale of surface land rights at its Central Appalachian operations in West Virginia in the third quarter of 2005. In the fourth quarter of 2005, the Company recognized a gain of $46.5 million on the sale of a rail spur, rail loadout and an idle office complex.

(f) In the first and fourth quarters of 2005, the Company recognized charges under its performance-contingent phantom stock awards of $9.9 million and $4.5 million, respectively, as a component of selling, general and administrative expense ($9.1 million and $4.5 million, respectively) and cost of coal sales ($0.8 million and $0), respectively.

(g) On May 15, 2006, the Company completed a two-for-one stock split of the Company s common stock in the form of a 100% stock dividend. All share and per share amounts have been retroactively restated for the split. The sum of the quarterly earnings (loss) per common share amounts may not equal earnings (loss) per common share for the full year because per share amounts are computed independently for each quarter and for the year based on the weighted average number of common shares outstanding during each period.

Table of Contents

Schedule II

Arch Coal, Inc. and Subsidiaries
Valuation and Qualifying Accounts

	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Charged to Other Accounts	Deductions(1)	Balance at End of Year
			(In thousands)		
Year ended December 31, 2006					
Reserves deducted from asset accounts:					
Other assets other notes and accounts Receivable	$ 1,777	$ 1,379	$	$	$ 3,156
Current assets supplies and inventory	15,335	614		527	15,422
Deferred income taxes	163,163	(49,129)			114,034
Year ended December 31, 2005					
Reserves deducted from asset accounts:					
Other assets other notes and accounts receivable	3,001	1,345	(944)(2)	1,625	1,777
Current assets supplies and inventory	22,976	(630)	(5,780)(2)	1,231	15,335
Deferred income taxes	163,005	(6,138)	6,296 (4)		163,163
Year ended December 31, 2004					
Reserves deducted from asset accounts:					
Other assets other notes and accounts receivable	1,469	570	962 (3)		3,001
Current assets supplies and inventory	18,763	1,746	3,010 (3)	543	22,976
Deferred income taxes	161,113	(265)	2,157 (4)		163,005

(1) Reserves utilized, unless otherwise indicated.

(2) Balance upon disposition of Central Appalachian operations.

(3) Balance at acquisition date of subsidiaries.

(4)

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

Table of Contents

Signatures

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Arch Coal, Inc.

Steven F. Leer
Chairman and Chief Executive Officer
March 1, 2007

Signatures	Capacity	Date
Steven F. Leer	Chairman and Chief Executive Officer (Principal Executive Officer)	March 1, 2007
Robert J. Messey	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2007
John W. Lorson	Controller (Principal Accounting Officer)	March 1, 2007
* James R. Boyd	Director	March 1, 2007
* Frank M. Burke	Director	March 1, 2007
John W. Eaves	President, Chief Operating Officer and Director	March 1, 2007
* Patricia F. Godley	Director	March 1, 2007

*	Director	March 1, 2007
Douglas H. Hunt		
*	Director	March 1, 2007
Brian J. Jennings		

Table of Contents

Signatures	Capacity	Date
*	Director	March 1, 2007
Thomas A. Lockhart		
*	Director	March 1, 2007
A. Michael Perry		
*	Director	March 1, 2007
Robert G. Potter		
*	Director	March 1, 2007
Theodore D. Sands		
*	Director	March 1, 2007
Wesley M. Taylor		

*By:

Robert G. Jones,
Attorney-in-fact

Table of Contents

Exhibit Index

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 (incorporated by reference to Exhibit 2.1 of the registrant s Annual Report on Form 10-K for the year ended December 31, 2005).
2.3	Amendment No. 2 to the Purchase and Sale Agreement, dated as of April 27, 2006, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.1 of the registrant s Quarterly Report on Form 10-Q for the period ended June 30, 2006).
3.1	Restated Certificate of Incorporation of Arch Coal, Inc. (incorporated by reference to Exhibit 3.1 of the registrant s Current Report on Form 8-K filed on May 5, 2006).
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).
10.1	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).
10.2	First Amendment to Credit Agreement, dated as of June 23, 2006, by and among Arch Coal, Inc., the banks party thereto, Citicorp USA, Inc., JPMorgan Chase Bank, N.A. and Wachovia Bank, National Association, each in its capacity as syndication agent, Bank of America, N.A. (as successor-by-merger to Fleet National Bank), as documentation agent, and PNC Bank, National Association, as administrative agent for the banks (incorporated by reference to Exhibit 10.1 of the registrant s Current Report on Form 8-K filed on June 27, 2006).
10.3	Second Amendment to Credit Agreement, dated as of October 3, 2006, by and among Arch Coal, Inc., the banks party thereto, Citicorp USA, Inc., JPMorgan Chase Bank, N.A. and Wachovia Bank, National Association, each in its capacity as syndication agent, Bank of America, N.A. (as successor-by-merger to Fleet National Bank), as documentation agent, and

	PNC Bank, National Association, as administrative agent for the banks (incorporated by reference to Exhibit 10.1 to the registrant s Current Report on Form 8-K filed on October 6, 2006).
10.4*	Employment Agreement, dated November 10, 2006, between Arch Coal, Inc. and Steven F. Leer (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by the registrant on November 16, 2006).
10.5*	Form of Employment Agreement for Executive Officers of Arch Coal, Inc. (other than Steven F. Leer) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by the registrant on November 16, 2006).
10.6	Coal Lease Agreement dated as of March 31, 1992, among Allegheny Land Company, 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).

Table of Contents

Exhibit	Description
10.7	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).
10.8	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).
10.9	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).
10.10	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).
10.11	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).
10.12	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).
10.13	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).
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	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).
10.19	Coal Lease (WYW127221) 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).
10.20	State Coal Lease executed October 1, 2004 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Ark Land Company and Arch Coal, Inc. as lessees, covering a tract of land located in Seiever County, Utah.
10.21	State Coal Lease executed September 1, 2000 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Canyon Fuel Company, LLC, as lessee, for lands located in Carbon County, Utah.
10.22	Federal Coal Lease executed September 1, 1996 by and between the Bureau of Land Management, as lessor, and Canyon Fuel Company, LLC, as lessee, covering a tract of land known as The North Lease in Carbon County, Utah.

Exhibit	Description
10.23	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).
10.24*	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).
10.25*	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).
10.26*	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).
10.27*	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).
10.28*	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).
10.29*	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).
10.30	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).
10.31	First Amendment to Receivables Purchase Agreement, dated as of April 24, 2006, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, 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 10.2 of the registrant s Quarterly Report on Form 10-Q for the period ended March 31, 2006).
10.32	Second Amendment to Receivables Purchase Agreement, dated as of June 23, 2006, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, the various financial institutions party thereto and PNC Bank, National Association, as administrator and as LC Bank (incorporated by reference to Exhibit 10.2 of the registrant s Current Report on Form 8-K filed on June 27, 2006).
10.33*	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).
10.34*	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).
10.35*	Form of Non-Qualified Stock Option Agreement.
12.1	Computation of ratio of earnings to combined fixed charges and preference dividends.
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.